COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. TO AMEND ITS DEMAND SIDE MANAGEMENT PROGRAMS	)))	CASE No. 2022-00251

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF DUKE ENERGY KENTUCKY, INC.

The Attorney General of the Commonwealth of Kentucky, through his Office of Rate Intervention ("AG"), submits the following responses to data requests of Duke Energy Kentucky, Inc. ("DEK," or "the Company") in the above-styled matter.

Respectfully submitted,

DANIEL CAMERON
ATTORNEY GENERAL

____
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<u>Certificate of Service</u>

Pursuant to the Commission's Orders in Case No. 2020-00085, and in accord with all other applicable law, Counsel certifies that an electronic copy of the forgoing was served and filed by e-mail to the parties of record. Counsel further certifies that the responses set forth herein are true and accurate to the best of his knowledge, information, and belief formed after a reasonable inquiry.

This 5th day of December, 2022

____
Assistant Attorney General

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. TO AMEND ITS DEMAND SIDE MANAGEMENT PROGRAMS	)))	CASE No. 2022-00251

AFFIDAVIT OF PAUL J. ALVAREZ

State of Colorado)

Paul J. Alvarez, being first duly sworn, states the following: The attached Data Request Responses are those of the Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Data Request Responses if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, information and belief his statements made are true and correct. Further affiant saith naught.

Paul J. Alvarez

SUBSCRIBED AND SWORN to before me this 1st day of December , 2022

Brad Cook
NOTARY PUBLIC

My Commission Expires: 06/06/2024

BRAD COOK
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20124033594
MY COMMISSION EXPIRES JUN 6, 2024

GENERAL OBJECTION: Unless otherwise noted in the following responses, Mt. Alvarez and the AG rely on the common English language definitions for all words set forth herein.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objections

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:

Objection, to the extent this question seeks information which is privileged under the work-product and/or attorney-client privilege(s). Without waiving these objections, the AG states: none.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 2
Page 1 of 1

For each person identified in (prior) response to Data Request 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 J. ALVAREZ

QUESTION No. 3
Page 1 of 1

For each person identified in response to Data Request No. 1 above, please identify all proceedings in all jurisdictions in which the witnesses/persons have 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 J. ALVAREZ / Counsel as to Objections

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 protected by the work product and/or attorney-client privileges. Without waiving these objections, the AG states he will provide counsel with a list of in-record exhibits he will or may introduce as hearing exhibits, at a reasonable time prior to the hearing, once they are identified.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. 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 (DSM); 2) costs of participating in PJM, including capacity and energy market evaluations; 3) peak-time rebate programs; and 4) time-of-use rates.

RESPONSE:

Mr. Alvarez has made no presentations on these topics within the last 3 years.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. 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, besides the Peak Time Rebate (PTR) Program Pilot.

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

RESPONSE:

Confirmed.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objections

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 protected by the work-product and/or attorney-client privilege. Without waiving these objections, the AG states that Mr. Alvarez's testimony speaks for itself.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

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:

A current list of jurisdictions in which Mr. Alvarez has appeared, including docket numbers and dates of submissions, was provided in Appendix A to Mr. Alvarez's testimony. Final commission decisions and orders are publicly available for all proceedings listed except for the two most recent (California PUC A.21-06-021 and Georgia PSC 44280). In the event the Company has any problems locating testimony or Orders, the AG asks the Company to provide a list and he will endeavor to obtain copies of the specified orders.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 9
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 provided one set of his workpapers, and Excel spreadsheet entitled "PTR Projected TRC AG.xlsx "simultaneously with the filing of his testimony. Another Excel document entitled "Day-Ahead and RT Energy Prices by Event Day Hour.xlsx" is being filed simultaneously with the instant responses.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objection

QUESTION No. 10
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. The question is unduly burdensome and is clearly designed to harass the witness. It is impossible for Mr. Alvarez to provide copies of all "documents. . . including but not limited to, analysis, summaries, cases, reports, evaluations, etc." he relied upon throughout the course of his training and expertise. Without waiving this objection, Mr. Alvarez states that his testimony identifies certain documents he relied upon. All such documents are publicly available, but some such documents may be subject to copyright restrictions, and thus cannot be reproduced and filed into the instant docket.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 11
Page 1 of 1

Please clarify if it is Mr. Alvarez's position that "universal PTR" (see pg. 35 of Mr. Alvarez's testimony) is the same things as "full PTR" (see pg. 36 of Mr. Alvarez's testimony). If the answer is in the negative, please provide Mr. Alvarez's definitions of both terms.

RESPONSE:

Mr. Alvarez clarifies that "Full PTR" and "Universal PTR" are not equivalent. "Full PTR" is any peak-time rebate program for which participation is made available to all residential and small commercial customers in the Company's service area (meaning, not limited to a pilot). "Universal PTR" is a specific type of Full PTR program in which customers need not complete any type of registration (automatic enrollment) to earn PTR program bill credits.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 12
Page 1 of 1

Please clarify if it is Mr. Alvarez's position that a PTR program should be part of the default rate/services for all Duke Energy Kentucky's residential and small commercial customers?

(a) Has Mr. Alverez performed any analysis of how a default PTR rate design for residential and small commercial customers would impact any of the Company's other customer classes?

(b) If Mr. Alverez's opinion is that the PTR should be an element of the default rate for all residential and small commercial customers, 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:

Mr. Alvarez considers a PTR program to be a tariffed rate credit that is available to all customers, to be offered in addition to the default rate for all Duke Energy Kentucky's residential and small commercial customers. Mr. Alvarez clarifies that a tariffed PTR rate credit available to all customers can be offered in two ways: 1) to all customers who register for them ("Full PTR"), or 2) to all customers without registration requirements (automatic enrollment).

(a) To a significant extent, yes, though Mr. Alvarez does not characterize his analysis as a class cost-of-service study. Please refer to Mr. Alvarez's testimony, page 28, and the Table "AG Projection of the Likely Benefits and Costs of a Full PTR Program in the DEK Service Area", as well as to the associated details provided in Appendix B. Mr. Alvarez assumes that projected Full PTR program benefits in excess of projected program costs inure to all customers. Thus, Mr. Alvarez's analysis indicates that all of the Company's other customer classes would benefit from a Full PTR program.

(b) Please refer to the response to DEK-AG-01-012(a).

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 13
Page 1 of 1

Is Mr. Alvarez aware of any jurisdictions that have approved a default, mandatory, universal, full, 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 notes that all PTR programs are voluntary, as customers can choose whether to reduce usage in response to a critical peak event notice or not. Of these, Mr. Alvarez distinguishes two types 1) PTR programs in which customers must register to receive rebates; and 2) PTR programs in which customers are automatically enrolled/eligible to receive rebates without registration. The chart below provides examples of each of which Mr. Alvarez is aware. Copies of the identified Orders from the states of Maryland and California are being filed in .pdf format simultaneously with the instant responses, as they are difficult to obtain. The orders from Illinois and Michigan can be obtained at the website for the Commissions in those states:

https://www.icc.illinois.gov/docket

https://mi-psc.force.com/s/

Jurisdiction	Utility	Enrollment	Docket/Case No.
Maryland PSC	BG&E	Automatic	9406
	Pepco	Automatic	9418
	Delmarva	Automatic	9424
California PUC	PG&E	Automatic*	R.20-11-03
	SoCal Edison	Automatic*	
	San Diego G&E	Automatic*	
Illinois CC	ComEd	Must Register	12-0484
	Ameren Illinois	Must Register	12-0244
Michigan PSC	Consumers Energy	Must Register	U-20134

* Automatic enrollment for these programs appears to be limited to certain customer populations, with a definition which varies from utility to utility.

ML 204346

ORDER NO. 87884

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR ADJUSTMENTS TO ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	* * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9418

Before: W. Kevin Hughes, Chairman
Harold D. Williams, Commissioner
Jeannette M. Mills, Commissioner
Michael T. Richard, Commissioner
Anthony J. O'Donnell, Commissioner

Issued: November 15, 2016

APPEARANCES

Peter E. Meier, Douglas E. Micheel, and Matthew K. Segers for Potomac Electric Power Company

Paula M. Carmody, Theresa V. Czarski, William F. Fields, Molly G. Knoll, Jacob M. Ouslander, and Joyce R. Lombardi for the Maryland Office of People's Counsel

Lloyd Spivak, Michael Dean, Peter A. Woolson and Annette B. Garofalo for the Public Service Commission Staff

Frann G. Francis and Nicola Whiteman for the Apartment and Office Building Association of Metropolitan Washington

Mark F. Sundback, Kenneth L. Wiseman, William M. Rappolt and Kevin Siqveland for Healthcare Council of the National Capital Area

Lisa Brennan for Montgomery County, Maryland

Mercia E. Arnold for POWERUPMONTCO

Jodi S. Schulz, Cynthia Walters and Debra Yerg Daniel for City of Rockville, Maryland

Whitney Cleaver Smith and James McGee for Prince George's County, Maryland

Heather Cameron for U.S. General Services Administration

N. Lynn Board for City of Gaithersburg

TABLE OF CONTENTS **Page**

I. INTRODUCTION AND EXECUTIVE SUMMARY

On April 19, 2016, Potomac Electric Power Company ("Pepco") filed with the Maryland Public Service Commission ("Commission") a request to increase its rates for electricity in the amount of $126,784,000.[1] Pepco has not increased its rates since July 2014, prior to its parent, Pepco Holdings, Inc.'s merger with Exelon Corporation. The Company's application for an increase was predominantly driven by the Company's request for recovery of its Advanced Metering Infrastructure ("AMI") investments, continued reliability infrastructure investments and the results of the Company's most recent depreciation filing[2]. Much of this increase, $60.9 million[3], is due to Pepco seeking to begin recovery for $97.2 million of capital investments made over the past six years in implementing new technology, its Advanced Metering Infrastructure system. The request also included $197.8 million[4] in base rates for cost recovery for the Company's ongoing reliability investments and an increase in the Company's authorized rate of return from 9.62% to 10.60%. The Company also requested a new extension of its Grid Resiliency Program, with a surcharge to concurrently recover costs in the amount of $31.6 million[5] for 2 years, or add approximately $15.8 million a year.

As in any rate case, we are required to balance the Company's recovery of its expenses and capital investments made to render safe and reliable service with the requirement that the rates it charges customers are "just and reasonable" and no more.

[1] During the course of the case Pepco reduced its request to $102,751,000.
[2] Pepco witness McGowan's direct testimony at 2.
[3] Pepco witness McGowan direct testimony at 7.
[4] Application filing April 19, 2016 at 2.
[5] Pepco witness McGowan direct testimony at 5.

We have thoroughly reviewed Pepco's Application and the evidence presented by all of the parties to the case, as well as the public's comments. After careful consideration, we authorize Pepco to increase its electric rates by $52,535,000.

In 2010, the Commission, and State and Federal policy makers, agreed that the various energy savings and operational efficiency benefits of the Advanced Metering Infrastructure (AMI) technology were in the public interest, and the Commission authorized Pepco to begin implementation of its AMI system. It deferred, however, cost recovery from ratepayers until Pepco could prove that it had delivered a cost beneficial system. The evidence presented by all of the parties indicated the Pepco's AMI system passed the cost beneficial requirement. Based on the cost beneficial determination, Pepco is entitled to begin recovering over the next ten years the amount it has expended to computerize its metering and billing systems. In doing so, we have carefully reviewed the prudency of Pepco's expenditures in deploying AMI, and have reduced its revenue requirement request for AMI by $5,338,000.

We have also carefully considered Pepco's request to collect $31.6 million in contemporaneous cost recovery from ratepayers for improvements to feeders and new reclosers on its distribution system in its proposed Grid Resiliency Plan. We have reserved concurrent cost recovery in the form of a surcharge to exceptional circumstances when we find that immediate improvement to reliability is needed. That is currently no longer the case for Pepco. Its own witness testified that these improvements were not necessary to meet Pepco's reliability targets for 2019. For this reason we have not required ratepayers to incur this additional cost.

Finally, the Company asserted in its Application that its return on equity during the test year (2015) was only 2.26%, far below its authorized rate of return of 9.62%. Consequently, the Company requested an increase in its return on equity to 10.60%. We carefully considered this request together with the evidence presented by the other parties. Based on the record in this case, we find that a reduced return on equity of 9.55% provides for a fair and appropriate return, and will allow Pepco to obtain any necessary capital investment at reasonable interest rates.

Our decision here to authorize Pepco an increase of $52,535,000 will result in an increase to the average monthly residential bill of $6.96, a 4.76% increase[6]. We do not grant any increase lightly, and we recognize that all Pepco customers, residential, commercial and industrial, will not welcome this increase. We are cognizant that particularly low-income customers and senior citizens on fixed incomes will be significantly impacted. As in prior cases, we have strived to limit rate impacts while allowing the Company to invest in safety and reliability and continue to modernize its distribution system for the benefit of its customers.

II. BACKGROUND

On April 19, 2016, Potomac Electric Power Company ("Pepco" or the "Company"), now a subsidiary of Pepco Holdings LLC ("PHI"),[7] filed an Application for Adjustments to its Retail Rates for the Distribution of Electric Energy ("Application")

[6] This is based on an average residential use of 925 kwh/month based on Commission Exhibit 8.

[7] In March 2016, Pepco Holdings, Inc. (i.e., PHI) completed a merger with Exelon Corporation, which is headquartered in Chicago, Illinois and does business in 48 states, the District of Columbia, and Canada. Prior to the merger, PHI was a multi-state energy delivery company operating in the Mid-Atlantic region and serving approximately 2 million customers in Maryland, the District of Columbia, New Jersey, and Delaware. PHI subsidiaries include Pepco, Delmarva Power (a regulated electric and natural gas utility operating in Delaware and the Delmarva Peninsula), and Atlantic City Electric (a regulated electric utility delivering electricity in southern New Jersey), all of which remain separate companies following the merger. PHI, now Pepco Holdings LLC, is an Exelon company.

pursuant to §§ 4-203 and 4-204 of the Public Utilities Article of the *Annotated*, *Code of Maryland* ("PUA"), for authority to increase its rates and charges for electric distribution service in Maryland. The Commission partially approved Pepco's last application for an electric rate increase two and a half years ago in July 2014.[8] In this Application, Pepco initially asked the Commission for authority to increase its Maryland distribution rates and charges by approximately $126,784,000. The Company used a 12-month test year ending December 31, 2015, which at the time of filing included nine (9) months of actual data and three (3) months of forecasted data. Pepco also requested that the Commission approve an increased return on equity ("ROE") of 10.60%, asserting that the Company is currently earning an adjusted ROE of 2.26%, which is arguably well below its previously authorized level of 9.62%.[9] According to Pepco, if the rates in the Application were granted in full, the monthly impact of the rate increase on the average residential Standard Offer Service ("SOS") customer using 1,000 kilowatt-hours ("kWh") of electricity per month would be $15.80 per month. The Application contained a proposed rate effective date of May 19, 2016.[10]

On April 20, 2016, the Commission docketed the Application as Case No. 9418 and issued an order setting in a prehearing conference for purposes of establishing a procedural schedule, considering motions to intervene and any other preliminary motions. In the same order, the Commission suspended Pepco's proposed tariff revisions for a period of 150 days pursuant to PUA § 4-204. The Commission also required Pepco to publish an advertisement in a newspaper(s) in general circulation throughout its service

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[8] *In re Potomac Electric Power Company*, Case No. 9336, Commission Order No. 86441 (July 2, 2014).
[9] April 19, 2016 Application at 4.
[10] April 19, 2016 Application at 4-5.

area at least twice prior to May 18, 2016, notifying interested persons of the prehearing conference.[11]

On May 23, 2016, the Commission held the prehearing conference. By Order No. 87569 issued that day, the Commission established a procedural and discovery schedule and extended the initial 150-day suspension period for the Company's tariff revisions for an additional 30 days, or until November 15, 2016. The Commission also granted petitions to intervene filed by: U.S. General Services Administration ("GSA"); City of Gaithersburg, Maryland ("Gaithersburg"); Montgomery County, Maryland ("Montgomery"); Prince George's County, Maryland ("Prince George's"); Mayor and Council of Rockville, Maryland ("Rockville"); Healthcare Council of the National Capital Area ("HCNCA"); POWERUPMONTCO of Montgomery County ("POWERUPMONTCO"); and Apartment and Office Building Association of Metropolitan Washington ("AOBA") (collectively, along with Pepco, Office of People's Counsel and Commission Technical Staff, the "Parties").

Pepco provided updates to its filing throughout the course of these proceedings. The Company provided a final update on September 8, 2016, to include a full year of actual data ending December 31, 2015.[12] The Company subsequently revised its requested revenue requirement to reflect not only actual results through August 2016 but also Pepco's willingness to accept five adjustments proposed of certain parties. In total, the Company reduced its initial position by approximately $24 million, inclusive of the accepted adjustments plus other true-ups and updates, to reach a final requested revenue

[11] *See* Order No. 87503.
[12] ML 198902.

requirement of $102,751,000. Pepco did not change its requested overall rate of return contained in its original application.

Numerous witnesses submitted written testimony on behalf of several parties in this proceeding. Along with its Application, Pepco sponsored the testimonies of: Kevin M. McGowan, Vice President of Regulatory Policy & Strategy for PHI, who testified on the general basis for the rate increase;[13] Karen R. Lefkowitz, Vice President of Smart Grid and Technology for PHI, who testified about the Company's AMI business case, its benefits and cost-effectiveness;[14] Mario A. Giovannini, Director of Energy Acquisition for PHI, who testified about the benefits of Pepco's AMI-enabled demand response initiatives and interval AMI data;[15] W. Michael VonSteuben, Special Projects Manager in the Regulatory Affairs Department of PHI, who testified about Pepco's revenue requirements, accounting issues, and ratemaking adjustments;[16] Christopher A. Nagle, Supervisor, Cost Allocation for Pepco, who testified about Pepco's jurisdictional and customer class cost of service studies ("COSS");[17] Joseph F. Janocha, Manager of Rate Economics for PHI, who testified regarding rate design and Pepco's proposed tariffs,

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[13] Pepco Ex. 3, Direct Testimony of Kevin M. McGowan ("McGowan Direct"); Pepco Ex. 4, Rebuttal Testimony of Kevin M. McGowan (McGowan Rebuttal").

[14] Pepco Ex. 7, Direct Testimony of Karen R. Lefkowitz ("Lefkowitz Direct"); Pepco Ex. 8, Rebuttal Testimony of Karen R. Lefkowitz ("Lefkowitz Rebuttal"); Pepco Ex. 9, Surrebuttal Testimony of Karen R. Lefkowitz ("Lefkowitz Surrebuttal").

[15] Pepco Ex. 10, Direct Testimony of Mario Giovannini ("Giovannini Direct"); Pepco Ex. 11, Rebuttal Testimony of Mario Giovannini ("Giovannini Rebuttal"); Pepco Ex. 12, Surrebuttal Testimony of Mario Giovannini ("Giovannini Surrebuttal").

[16] Pepco Ex. 18, Direct Testimony of W. Michael VonSteuben ("VonSteuben Direct"); Pepco Ex. 19, Supplemental Direct Testimony of W. Michael VonSteuben ("VonSteuben Supplemental Direct"); Pepco Ex. 20, Rebuttal Testimony of W. Michael VonSteuben ("VonSteuben Rebuttal"); Pepco Ex. 21, Surrebuttal Testimony of W. Michael VonSteuben ("VonSteuben Surrebuttal").

[17] Pepco Ex. 29, Direct Testimony of Christopher A. Nagle ("Nagle Direct"); Pepco Ex. 30, Supplemental Direct Testimony of Christopher A. Nagle ("Nagle Supplemental Direct"); Pepco Ex. 31, Rebuttal Testimony of Christopher A. Nagle ("Nagle Rebuttal").

including the Grid Resiliency Charge ("GRC");[18] and William M. Gausman, Senior Vice President Strategic Initiatives for PHI, who testified about the Company's investments in reliability, its distribution construction program, and its proposal for a continuation of the Grid Resiliency Plan ("GRP").[19] Two additional witnesses testified on behalf of Pepco: Ahmad Faruqui, a Principal with The Brattle Group, who testified about the Company's use of energy management and conservation tools as a benefit of AMI;[20] and Robert B. Hevert, Managing Partner of Sussex Economic Advisors LLC, who testified regarding the Company's cost of equity.[21]

The Public Service Commission Technical Staff ("Staff") presented the testimonies of: Phillip E. VanderHeyden, Director of the Electricity Division, who testified regarding the return on equity and overall rate of return for determining Pepco's electric distribution rates and offered critique of Pepco's cost of capital testimony;[22] Loubens Blaise, a Regulatory Economist in the Electricity Division, who testified regarding the electric rate design and Pepco's GRC rider;[23] Dr. C. Shelley Norman, an Assistant Director in the Electricity Division, who testified regarding the cost of service

[18] Pepco Ex. 32, Direct Testimony of Joseph F. Janocha ("Janocha Direct"); Pepco Ex. 33, Supplemental Direct Testimony of Joseph F. Janocha ("Janocha Supplemental Direct"); Pepco Ex. 34, Rebuttal Testimony of Joseph F. Janocha ("Janocha Rebuttal").

[19] Pepco Ex. 16, Direct Testimony of William M. Gausman ("Gausman Direct"); Pepco Ex. 17, Rebuttal Testimony of William M. Gausman ("Gausman Rebuttal"). Pepco initially included with its Application the prepared direct testimony of Charles R. Dickerson, whose testimony covered the same topics as Mr. Gausman. On May 17, 2016, Pepco filed Mr. Gausman's Direct Testimony which adopted Mr. Dickerson's testimony, filed previously on April 19, 2016. Pepco advised the Commission that Mr. Dickerson was no longer an employee of PHI and was unavailable to present testimony in the proceedings.

[20] Pepco Ex. 13, Direct Testimony of Ahmad Faruqui ("Faruqui Direct"); Pepco Ex. 14, Rebuttal Testimony of Ahmad Faruqui ("Faruqui Rebuttal"); Pepco Ex. 15, Surrebuttal Testimony of Ahmad Faruqui ("Faruqui Surrebuttal").

[21] Pepco Ex. 5, Direct Testimony of Robert B. Hevert ("Hevert Direct"); Pepco Ex. 6, Rebuttal Testimony of Robert B. Hevert ("Hevert Rebuttal").

[22] Staff Ex. 19, Direct Testimony and Exhibits of Phillip E. VanderHeyden ("VanderHeyden Direct"); Staff Ex. 20, Surrebuttal Testimony of Phillip E. VanderHeyden ("VanderHeyden Surrebuttal").

[23] Staff Ex. 16, Direct Testimony and Exhibits of Loubens Blaise ("Blaise Direct"); Staff Ex. 17, Surrebuttal Testimony of Loubens Blaise ("Blaise Surrebuttal").

for Pepco's electric operations as well as AMI meter cost allocation;[24] Felicia L. Shelton, a Staff Engineer, who testified regarding Pepco's reliability, infrastructure replacement, automation, and other capital projects as well as associated rate base adjustments;[25] J. Andrew Dodge, Sr., Chief Engineer, who testified regarding Pepco's storm mobilization and mutual assistance costs associated with Winter Storms PAX and Jonas;[26] Daniel J. Hurley, Director of the Commission's Energy Analysis and Planning Division, who testified regarding the costs, benefits and cost-effectiveness of Pepco's AMI deployment;[27] and Mikhail Ratushny, a Staff Engineer, who testified regarding the benefits of Pepco's AMI program.[28] Additionally, Staff submitted both confidential and public testimony from Bion C. Ostrander, an independent regulatory consultant, who testified on behalf of Staff regarding Pepco's revenue requirements.[29]

The Office of People's Counsel ("OPC") presented the testimonies of: David J. Effron, an independent consultant specializing in utility regulation, who testified regarding Pepco's revenue requirements including rate base and operating income adjustments;[30] Dr. J. Randall Woolridge, Professor of Finance at Pennsylvania State University, who testified regarding the cost of capital for Pepco's regulated electric

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[24] Staff Ex. 18, Direct Testimony and Exhibits of C. Shelley Norman, Ph.D. ("Norman Direct").

[25] Staff Ex. 14, Direct Testimony and Exhibits of Felicia L. Shelton ("Shelton Direct"); Staff Ex. 15, Surrebuttal Testimony of Felicia L. Shelton ("Shelton Surrebuttal").

[26] Staff Ex. 21, Direct Testimony and Exhibits of J. Andrew Dodge, Sr. ("Dodge Direct"); Staff Ex. 22, Surrebuttal Testimony and Exhibits of J. Andrew Dodge, Sr. ("Dodge Surrebuttal").

[27] Staff Ex. 24, Direct Testimony and Exhibits of Daniel J. Hurley ("Hurley Direct"); Staff Ex. 25, Surrebuttal Testimony of Daniel J. Hurley ("Hurley Surrebuttal").

[28] Staff Ex. 11, Direct Testimony of Mikhail Ratushny ("Ratushny Direct"); Staff Ex., 12, Surrebuttal Testimony of Mikhail Ratushny ("Ratushny Surrebuttal").

[29] Staff Ex. 26, Public Version Direct Testimony and Exhibits of Bion C. Ostrander and Staff Ex. 26C, Confidential Version Direct Testimony and Exhibits of Bion C. Ostrander (collectively, "Ostrander Direct"); Staff Ex. 27, Rebuttal Testimony of Bion C. Ostrander ("Ostrander Rebuttal"); Staff Ex. 28, Surrebuttal Testimony and Exhibits of Bion C. Ostrander ("Ostrander Surrebuttal").

[30] OPC Ex. 8, Direct Testimony of David J. Effron ("Effron Direct"); OPC Ex. 9, (Errata) Surrebuttal Testimony of David J. Effron ("Effron Surrebuttal").

distribution service and addressed its rate of return testimony;[31] Karl R. Pavlovic, a Senior Consultant and Managing Director of PCMG and Associates LLC, who testified regarding Pepco's electric class distribution costs of service, revenue requirement distribution, and rate design;[32] Peter J. Lanzalotta, a Principal with Lanzalotta & Associates, LLC, who testified regarding Pepco's distribution system planning and reliability matters;[33] Nancy Brockway, a former Commissioner of the New Hampshire Public Utilities Commission, who testified regarding ratemaking in connection with legacy meters, metrics-gathering in connection with Pepco's Smart Meter deployment, and Pepco's future AMI benefits;[34] Maximilian Chang, a Principal Associate with Synapse Energy Economics, who testified regarding the benefit-to-cost analysis for Pepco's AMI deployment;[35] and Paul L. Chernick, President of Resource Insight, Inc., who testified regarding some of the benefits Pepco asserts with its AMI investment.[36]

AOBA presented the testimonies of: Bruce R. Oliver, President of Revilo Hill Associates, Inc., who testified regarding Pepco's cost of capital, new billing system, cost of service, and cost-benefit analysis for AMI;[37] and Timothy B. Oliver, a Project Manager and Senior Rate Analyst for Revilo Hill Associates, Inc., who testified

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[31] OPC Ex. 21, Direct Testimony of Dr. J. Randall Woolridge ("Woolridge Direct"); OPC Ex. 22, Rebuttal Testimony of Dr. J. Randall Woolridge ("Woolridge Rebuttal"); OPC Ex. 23, Surrebuttal Testimony of Dr. J. Randall Woolridge ("Woolridge Surrebuttal").

[32] OPC Ex. 18, Direct Testimony of Karl R. Pavlovic ("Pavlovic Direct"); OPC Ex. 19, Rebuttal Testimony of Karl R. Pavlovic ("Pavlovic Rebuttal"); OPC Ex. 20, Surrebuttal Testimony of Karl R. Pavlovic ("Pavlovic Surrebuttal").

[33] OPC Ex. 10, Direct Testimony of Peter J. Lanzalotta ("Lanzalotta Direct"); OPC Ex. 11, Surrebuttal Testimony of Peter J. Lanzalotta ("Lanzalotta Surrebuttal").

[34] OPC Ex. 12, Direct Testimony of Nancy Brockway ("Brockway Direct"); OPC Ex. 13, Surrebuttal Testimony of Nancy Brockway ("Brockway Surrebuttal").

[35] OPC Ex. 17, Direct Testimony of Maximilian Chang ("Chang Direct").

[36] OPC Ex. 14, Direct Testimony of Paul Chernick ("Chernick Direct"); OPC Ex. 15, Rebuttal Testimony of Paul Chernick ("Chernick Rebuttal"); OPC Ex. 16, Surrebuttal Testimony of Paul Chernick ("Chernick Surrebuttal").

[37] AOBA Ex. 29, Direct Testimony of AOBA Witness Bruce R. Oliver ("B. Oliver Direct"); AOBA Ex. 30, Surrebuttal Testimony of AOBA Witness Bruce R. Oliver ("B. Oliver Surrebuttal").

regarding Pepco's revenue increase distribution and non-residential rate design proposals.[38] Lastly, HCNCA presented the testimony of Richard A. Baudino, a regulatory consultant with Kennedy and Associates, who testified regarding Pepco's cost of equity, revenue requirements, cost and revenue allocation, and rate design.[39]

The Commission held evidentiary hearings in its offices on September 13, 14, 15, 16, 19, 20, 21, and 22, 2016. Additionally, evening public comment hearings were held on September 6 and 8, 2016, in Rockville, Maryland and Largo, Maryland, respectively, for the purpose of listening to public comments on the Application. Parties filed Initial Briefs on October 13, 2016, and Reply Briefs on October 26, 2016.

On September 9, 2016, prior to the start of the evidentiary hearings, Staff filed a Summary of Positions on Revenue Requirements (hereinafter, the "Chart") on behalf of the Parties. Staff filed a revised version of the Chart on September 30, 2016. The Chart reflects the Parties' final positions on Pepco's total revenue requirement. Pepco's final position requests a revenue requirement of $102,751,000 for its electric distribution operations. Staff recommends a revenue requirement of no more than $57,759,000, while OPC recommends a revenue requirement of no more than $53,075,000. AOBA recommends a revenue requirement of no more than $51,462,000, and HCNCA similarly recommends that Pepco receive no more than $55,930,000.

All of the evidence presented in this case, including the public's comments, has been thoroughly reviewed and carefully considered by the Commission in reaching the decisions in this Order.

[38] AOBA Ex. 28, Direct Testimony of AOBA Witness Timothy B. Oliver ("T. Oliver Direct").

[39] HCNCA Ex. 30, Direct Testimony of Richard A. Baudino ("Baudino Direct"); HCNCA Ex. 31, Rebuttal Testimony of Richard A. Baudino ("Baudino Rebuttal"); HCNCA Ex. 32, Surrebuttal Testimony of Richard A. Baudino ("Baudino Surrebuttal").

III. DISCUSSION AND FINDINGS

A. Advanced Metering Infrastructure (AMI)

1) Background

Case No. 9111

The Commission initiated Case No. 9111 in January 2007 to evaluate BGE's proposal to implement demand-side management and Advanced Metering Infrastructure. In March of 2007, Pepco filed a similar proposal in Case 9111 – its "Application for Authorization to Establish a Demand-Side Management ["DSM"] Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group".[40]

Pepco's Application described its "Blueprint for the Future", but lacked a timetable for deployment or a business case in support thereof. In June 2007, the Commission established a "collaborative process" to consider a series of issues related to an advanced metering initiative and demand side management programs for all utilities that had filed applications.[41] In Order No. 81637, the Commission finalized these issues and "direct[ed] all electric companies to develop and file comprehensive energy efficiency, conservation and demand reduction plans proposing programs designed to achieve usage reductions goals in total electric consumption for each electric company by calendar year 2015."[42]

Case No. 9207

Following this directive, Pepco and Delmarva Power & Light Company submitted a joint proposal to deploy AMI in Maryland and establish a regulatory asset to defer

[40] Case No. 9111, Item No. 13.
[41] Order No. 81148.
[42] Order No. 81637 at 1.

recognition of AMI-related incremental costs.[43] In approving the proposed system, "we recognize[ed] the potential of AMI to deliver substantial benefits to the Companies' customers".[44] These benefits included operational and maintenance benefits (O&M), such as eliminating manual meter readers, enabling remote service connections, improving billing activities, among others.

The Commission determined, as it had previously with BGE, that

> The majority of AMI-enabled cost savings projected by the Companies arise from PHI's predictions about the degree to which the dynamic pricing options they propose will motivate customers to reduce electricity usage during Company-declared critical peak demand periods, and the impact of that reduction on wholesale market prices.[45]

Although we authorized the deployment of Pepco's AMI system, we ordered Pepco to submit for Commission approval:

> (1) a comprehensive education plan with associated costs (to be implemented sufficiently in advance to maximize customer awareness);
> (2) a comprehensive set of metrics for all aspects of its AMI implementation, including installation and performance the system, incremental costs and benefits incurred, the effectiveness of its customer education plan and customer privacy and cybersecurity.[46]

We ordered Pepco to report their performance against these metrics and "appear for periodic hearings" to allow the Commission to evaluate its progress.[47]

Pepco had projected a benefits-costs-ratio of 2.696 after receiving funding from the United States Department of Energy.[48] After acknowledging that uncertainties are inherent in the PHI Companies' business cases, we nevertheless approved Pepco's

[43] The PHI Companies also sought to develop and submit certain dynamic pricing tariffs. However, the Commission did not approve this aspect of the proposal.
[44] Order No. 83571 at 1.
[45] *Id*. at 2. We noted that the PHI Companies had based their projections on a BGE pilot program but had done no pilots of their own.
[46] Order No. 83571 at 54.
[47] *Id.*
[48] *Id.* at 41.

request to establish a regulatory asset for incremental costs associated with AMI deployment to be offset "by known and quantifiable AMI-related cost savings.[49] We further observed that establishing a regulatory asset better synchronizes the timing of customer costs and benefits, "thereby providing an opportunity for ongoing review of the Proposal's cost-effectiveness in future rate cases."[50] We concluded that our determination regarding recovery of prudently-incurred AMI-related costs "will be informed by whether the Companies have, in fact, delivered a cost-effective AMI system, the individual and collective benefits of which are worth the ratepayers' investment."[51]

2) Pepco's Current Cost-Benefit Analysis

a. <u>Pepco's Position</u>

Pepco has installed 568,000 meters in Maryland. Only 1,100 customers chose to opt-out of receiving a smart meter, and this percentage is small enough to have no effect on their business case.[52]

Pepco provided several witnesses and thousands of pages of testimony and exhibits to substantiate its contention that its AMI system exceeds the cost-beneficial threshold we established in Case No. 9207. Specifically, Pepco contends that its customers receive $3.54 in benefits for every $1.00 invested in the system and for which it seeks recovery.[53] Those investments include $93.3 million in capital costs as of the end of the test year.[54] As we directed in Order No. 83571, Pepco has deferred its costs (net of operational cost reductions) in a regulatory asset. Pepco includes this asset in its cost-

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[49] *Id.* at 52.
[50] *Id.*
[51] *Id.* at 53.
[52] Lefkowitz Direct at 3.
[53] Application at 3; Lefkowitz Direct at 10-12, including Graph 1.
[54] Lefkowitz Direct at 16, Table B.

benefit analysis, the balance of which is $61 million as of October 31, 2016.[55] These deferred costs reflect "AMI-related incremental depreciation expense, AMI and Dynamic-Pricing-related deferred O&M savings as well as AMI and Dynamic-Pricing related deferred returns."[56]

Pepco also includes $35.975 million in incremental operational and maintenance costs for both deployment and post-deployment periods (2013 through 2023) in its business case.[57] For present value calculations, forecasted annual costs (revenue requirements) and benefits are discounted at Pepco's weighted average utility cost of capital, and benefits achieved prior to 2016 are elevated at the same rate.[58]

Pepco witness Ms. Karen Lefkowitz is Pepco's Vice President of Smart Grid and Technology for PHI, and she provides a comprehensive overview of Pepco's contention that its AMI system provides ratepayers a benefit-cost ratio of 3.54-1, higher than initially estimated when the Commission approved Pepco's initiative.[59]

Pepco's divides its AMI-related costs between:

> 1) Costs associated with the AMI system in the amount of $93.3 million, with $65.2 million attributed to the cost of the meters, $4.3 million associated with the communication network and $23.8 million associated with information technology;[60]
>
> 2) Recovery of deferred costs – those costs placed in a regulatory asset per our prior order and which total $61 million;[61] and
>
> 3) Ongoing O&M and capital costs, which are estimated to be $35,975,000 and $21,254,000 respectively between 2016 and 2023.[62]

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55 *Id.* at 17.
56 McGowan Direct at 7-8.
57 *Id.* at 7.
58 Lefkowitz Direct at 14.
59 *Id.* at 13 (Table A)
60 *Id.* at 13, 16.
61 *Id.* at 13, 16-17.
62 *Id.* at 18. Tables D and E. Pepco's AMI deployment began in 2014. We ordered a ten-year depreciation period in Case No. 9207, a period which ends in 2023.

Pepco divides the benefits its AMI system provides into two categories: Operational Benefits and Demand-Side Related Savings. The chart below summarizes both sides of the ledger:

	Cumulative Cost Benefits	Present Value[63]
Costs[64]		
1. AMI System[65]	$ 93.3	$ 73.8
2. Recovery of Deferred Costs[66]	$ 61.0	$ 66.7
3. Ongoing O&M Costs[67]	$ 36.0	$ 27.1
4. Ongoing Capital Costs[68]	$ 21.3	$ 7.9
Total Costs	**$ 211.6**	**$ 175.5**
Benefits		
1. Operational		
a. O&M Benefits (as described in Table F)	$ 133.6	$ 122.9
b. Asset Optimization	$ 31.7	$ 23.6
c. PJM Mkt Revenues	$ 36.2	$ 35.2
d. Avoided T&D capital Expenditures		
i. CVR Initiatives[69]	$ 13.9	$ 10.3
ii. Dynamic Pricing Initiatives	$ 110.8	$ 94.9
iii. EMT Initiatives	$ 23.4	$ 20.0
	$ 148.1	$ 125.2
Total Operational Benefits	**$ 349.6**	**$ 306.9**
2. Demand Side Related Savings		
a. Conservation Voltage Reduction (CVR)		
i. Capacity & Energy Mitigation	$ 8.1	$ 5.3
ii. Avoided Capacity Energy	$ 68.9	$ 51.4
iii. Reduction in Air Emissions	$ 2.0	$ 1.5
	$ 79.1	$ 8.2
b. Dynamic Pricing (DP)		
i. Capacity & Energy Mitigation	$ 147.0	$ 150.6
ii. Avoided Capacity Energy	$ 43.5	$ 28.0
iii. Reduction in Air Emissions	$ 0.0	$ 0.0
	$ 190.5	$ 178.6
c. Energy Management Tools (EMT)		
i. Capacity & Energy Mitigation	$ 12.0	$ 9.7
ii. Avoided Capacity Energy	$ 79.4	$ 65.7
iii. Reduction in Air Emissions	$ 2.2	$ 1.8
	$ 93.7	$ 77.2
Total Demand Side Benefits	**$ 363.2**	**$ 314.1**
Total Benefits	**$ 712.9**	**$ 621.0**
Benefit Cost Ratio		**3.54**

Pepco further breaks down its operational benefits into 25 categories, generally described as O&M Benefits, Asset Optimization Benefits, PJM Market Revenues, and Avoided Transmission and Distribution Capital Expenditures. Ms. Leftowitz describes how each of these 25 categories benefits ratepayers, and we need not repeat them here.[70]

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[63] Costs shown on a revenue requirement basis present value as of 11/1/2016
[64] Net of $705million ARRA grant.
[65] Capital costs as shown on Table B Present value figure as adjusted for depreciation and taxes.
[66] Deferred costs as of 10/31/16 ; 561 million as noted in table C.
[67] Refer to Table D.
[68] Refer to Table E.
[69] CVR costs of 52 million are netted from benefits.
[70] For these descriptions, see *generally* Lefkowitz at 26-47.

Pepco claims the avoided T&D capital expenditures of $125,237,000 as operational benefits derived from its demand side savings because reduced demand for electricity allows Pepco to defer construction of additional transmission and distribution assets.[71]

Witness Faruqui, using a "robust analytical method," calculated the degree to which AMI meters and AMI-enabled programs reduced electricity consumption within Pepco's service territory.[72] Specifically, Mr. Faruqui concluded that these tools reduced residential electricity consumption by 1.73%.[73]

Pepco Witness Giovannini calculated that AMI-enabled programs – specifically Conservation Voltage Reduction ("CVR"), Dynamic Pricing ("DP") and Energy Management Tools ("EMTs") – have produced or will produce $314,000,000 in demand-side savings for Pepco's customers between 2013 and 2023.[74]

These savings anticipate a significant reduction in overall energy use as well as during peak demands. By participating in the PJM capacity auctions, Pepco can sell demand reductions into the wholesale capacity markets and earn PJM capacity market revenue. Mr. Giovannini testified that this revenue totaled $12.8 million through year-end 2015.[75] Additionally, PJM has accepted Pepco's bid of DP-sourced dynamic pricing valued at $32.5 million through 2019.[76]

Pepco's Dynamic Pricing model includes the ability for customers to earn distribution credits on "Peak Savings Days" of $1.25 for each kWh by which they reduce

[71] Lefkowitz Direct at 45.
[72] Faruqui Direct at 2.
[73] *Id.*
[74] Giovannini Direct at 4.
[75] *Id.*at 7.
[76] *Id.*

electricity consumption, with capacity market revenue in excess of these credits flowing through the EmPower Maryland surcharge.[77] Mr. Giovannini conceded that these revenues will not be available after 2020 due to a change in PJM rules, but described a number options being investigated to replace this revenue stream after 2020.[78]

Pepco included "Avoided Capacity Costs" in its cost-benefit analysis because PJM's Base Residual Auction treats its dynamic pricing programs as a generation asset, thereby reducing the total cost of capacity for a specific PJM utility zone.[79] "Avoided energy costs" simply refers to the reduced amount of energy that customers purchase when consumption declines.[80]

"Capacity Price Mitigation" and "Energy Price Mitigation" work along similar lines. When DP programs reduce demand, this lowers the clearing price during PJM's Base Residual Auction or the real-time electricity price because demand decreases while the supply remain constant.[81]

Pepco claims that it analyzed these costs and benefits from the customer's perspective, using the annual revenue requirement to measure both the costs and the "quantified" benefits from 2016 through 2023.[82] Pepco seeks to recover these costs amortized over a ten-year period, which Pepco claims all parties agreed to in Pepco's

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[77] *Id.*
[78] *Id.* at 9-10.
[79] *Id.* at 11-12.
[80] *Id.*at 13.
[81] *Id.*at 13-17.
[82] Pepco Initial Brief at 8.

latest depreciation case.[83] Pepco seeks to amortize its regulatory asset over five years.[84]

Pepco points out that, while there may be differences among the parties as to which costs or benefits should be included in the analysis, no party presents a business case that establishes that the system is not cost-effective.

b. Staff Response

Staff did not include in its evaluation of Pepco's business case several categories of benefits that were not "Core Benefits' as defined by Staff analysts. Staff Witness Hurley defined "Core Benefits" as "a benefit in the Business Case in Case No. 9207 and for which a reporting metric was developed in the Work Base Group Phase I or Phase IIA consensus metrics reporting guidelines."[85]

Based upon this definition, Mr. Hurley analyzed less than half of the benefits (and associated costs) claimed by Pepco.[86] Mr. Hurley concluded that Pepco's "Core Benefits" totaled $279 million with associated costs of $176 million, resulting in a benefit-cost ratio of 1.6-1.[87] Mr. Hurley and Staff Witness Ratushny therefore concluded that Pepco's AMI system was cost-beneficial exclusive of non-core benefits. Based upon these results, Staff concluded that "there is no evidence in the record that would support a finding that Pepco's AMI system is not cost-effective."[88]

c. OPC Response

OPC disagrees with many of Pepco's claimed benefits and costs, which it views as speculative or simply inaccurate. But even after adjusting for the many benefits and

83 McGowan Direct at 6.
84 McGowan Direct at 6.
85 Hurley Direct at 20.
86 Hurley Direct at 23. Compare the chart at Hurley Direct at 19 and Hurley Direct at 23.
87 Hurley Direct at 25.
88 Staff Initial Brief at 30.

costs that OPC finds dubious, its Witness Chang still concludes that a reasonable estimate of the benefits-costs is 0.99-1.00.[89] Mr. Chang conceded that this ratio is essentially "break-even" for ratepayers.[90] In fact, he also conceded that if he removed peak demand payments from his analysis (as we clearly ordered should be done in Case No. 9406), his ratio would increase 1.4 to 1, not very different from Staff's conclusion.[91] Therefore, OPC concluded that"[E]ven though the Company has greatly over-estimated the benefit-cost ratio for its AMI program, because the benefit-cost ratio found by OPC's analysis is so close to 1.0, OPC's revenue requirements witness, Mr. Effron, did not propose a disallowance to hold customers harmless from the amount of costs in excess of the benefits."[92]

d. <u>Montgomery County Response</u>

Montgomery County also contends that the Commission should approve the AMI system, concluding that "[t]here appears to be no dispute that Pepco has delivered a cost-effective Advanced Metering ("AMI") system."[93]

e. <u>Healthcare Council of the National Capital Area Response</u>

HCNCA did not submit a business case to support the conclusion that Pepco's AMI System was not cost effective. However, HCNCA argued that Pepco had the burden to establish cost-effectiveness for each class of customers separately and failed to do so (or even try) for commercial customers.[94] As a result, certain classes of

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[89] OPC Witness Chang at 23.
[90] Tr. 1205 (Chang).
[91] Tr. 1210; Hurley Surrebuttal at 4.
[92] OPC Initial Brief at 41-42.
[93] Montgomery County Initial Brief at 7.
[94] HCNCA Initial Brief at 28.

commercial customers would likely shoulder a greater burden of the costs of AMI while being unable to receive many of the benefits.[95]

f. <u>AOBA Response</u>

In its Initial Brief, AOBA contended for the first time that Pepco's benefit-cost ratio should be reduced to 0.66-1.0. AOBA did not produce an affirmative business case that would support this reduced ratio, but did criticize several of Pepco's costs and benefits, including Mr. Faruqui's methodology, the exclusion of dynamic peak pricing rebates from the cost-benefit analysis and the likelihood that financing the second round of smart meters will be much higher due to inflation and the absence of federal funding.

3. Commission Decision

In light of the record evidence before us, we approve Pepco's requested recovery of its AMI costs. All parties that submitted a business case agree that Pepco has provided a cost-beneficial AMI system, and disagree only on the extent to which it is cost-beneficial.[96] We have not required utilities to establish a particular cost-benefit ratio, only that they demonstrate that their system is cost-beneficial – a pass/fail proposition. We therefore need not address specifically whether Pepco, Staff or OPC provided a cost-benefit ratio closer to our own liking because doing so would be a moot analysis. Our order authorizing the deployment of AMI and the creation of a regulatory asset for related incremental costs demanded that Pepco meet the cost-beneficial threshold, and the record contains evidence that they have done so.

While the Commission agrees that Pepco has "passed" the cost-benefit test, we make note that due to this investment in AMI, both residential and commercial customers

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[95] As an example, businesses lack the flexibility to shift electricity usage during peak times or otherwise alter electricity consumption to the degree available to residential customers.

will experience additional costs on their monthly distribution bills. We note that Pepco has asserted, and Staff largely agrees, that AMI will result in significant operating and maintenance (O&M) and energy savings. It is imperative that these savings are noticeable and demonstrable to customers over the life of AMI. Just as the Commission expressed skepticism in some elements of the cost benefit analysis in reviewing BGE's AMI system[97], customers will want to see concrete savings to find value in their new meters. Therefore, Pepco should continue to demonstrate and communicate to its customers that its AMI program will result in direct monetary benefits and continue to develop ways to increase the types and amounts of direct monetary benefits that customers can receive in the future. We look forward to reviewing the Company's progress on this important customer issue.

Furthermore, as we stated in approving cost recovery of BGE's AMI investment[98], this Commission will remain vigilant with regard to Pepco fully utilizing smart grid technology to optimize the investment in AMI, and we expect Pepco to ensure that ratepayers realize a demonstrable return on their investment in smart grid technology. Regarding the company's avoided transmission and distribution capital expenditures (T&D), we require – as we did with BGE – that Pepco file a Distribution Investment Plan within twelve (12) months of the date of this Order that sets forth how the Company will accomplish these T&D goals. The required Plan shall analyze in detail the Company's strategy over the next five years for investing in its distribution system and shall include, among other things, specifics about how the Company's investment in smart meters will be utilized to improve the efficiency and effectiveness of the

[97] Hurley Direct at 10
[98] Order No. 87591 at 58.

distribution network. In addition, this Commission continues to believe AMI has great potential to give customers access to information, control, and cutting-edge services – some or many of which could be supplied by innovative third-parties.[99] For the customers' large investment in AMI to continue to be a success, Pepco and all distribution services companies must continue to unlock AMI's full value.

HCNCA claims that Pepco failed to establish cost-beneficial for each class of customers and failed to do so for commercial customers. However, the Commission language cited by HCNCA (from Case No. 9207, in which we initially approved Pepco's AMI deployment) states the opposite. The Commission wrote:

> And as the Companies own expert witness testified, Pepco's and Delmarva's small commercial customers are not expected to respond to dynamic pricing under the current Proposal, raising questions about whether the Proposal will be cost-effective for all classes of PHI even if it proves cost-effective on the whole.[100]

The Commission went on to identify several operational benefits that would accrue to commercial customers, but the Commission has never required that a utility demonstrate cost-effectiveness for every class of customers before it may recover its AMI costs. However, HCNCA raises legitimate concerns that commercial customers will pay a greater share of the costs of AMI than justified by the benefits they receive. As we discuss below, we have adopted a benefits-based allocation of AMI costs among rate classes, which should address many of the concerns HCNCA raises.

Waiting until its initial brief, AOBA contends that its criticisms of Pepco's purported benefits and costs results in a ratio of .66-1.0.[101] AOBA never submitted a written business plan to this effect, and this is not a minor omission. The other parties to

[99] The Commission looks forward to exploring this topic in Public Conference 44.
[100] Order No. 83571 at 43.
[101] AOBA Initial Brief at 39.

this case presented their view on this issue in accordance with the scheduling deadline. Had AOBA presented these parties with its own purported cost-benefit ratio and identified witnesses who would testify in support of that ratio, other parties would have had an opportunity to conduct discovery and cross-examine supporting witnesses as to their assumptions, including how the ratio would change if the Commission rejected some or all those assumptions.

We will nonetheless address most of AOBA's contentions. First, AOBA challenges Witness Faruqui's analytical model for estimates of load reduction due to Pepco's CVR and DP programs.[102] AOBA provides no witness or exhibit to support this contention. Rather, counsel for AOBA argues that his cross-examination was sufficient to demonstrate that Dr. Faruqui's conclusions are not tenable.[103] However, Dr. Faruqui provided a detailed explanation as to how he calculated load reduction while under oath.[104]

AOBA then contends that Pepco's legacy meters are not sunk costs, and the Commission should include the costs associated with the unamortized balance of legacy meters when analyzing AMI's cost-beneficial.[105] Although the treatment of Pepco's legacy meters is a legitimate issue in this case outside of our AMI analysis, we have already ruled in identical circumstances that these costs should not be included when we evaluated the cost-effectiveness of BGE's AMI system.[106] AOBA is aware of this, but seeks a *de novo* review of our prior ruling. However, OPC witnesses Chernick and Brockway made the same arguments that AOBA is making here, and we have already

[102] *Id.* at 28-30.
[103] *Id.* at 27-30.
[104] Tr. 565-569 (Faruqui).
[105] AOBA Initial Brief at 30-35.
[106] Order No. 87591 at 64.

addressed those arguments and concluded that the unamortized balance of BGE's legacy meters "constitutes a sunk cost that is not appropriately included in the cost-benefit analysis for this new initiative."[107] We agree with the testimony of Dr. Faruqui that "Costs related to prior decisions are not relevant to the cost-effectiveness of a new decision about new investments."[108]

AOBA also contends that Pepco's increased metering and billing costs should be included in the cost-benefit analysis, but several Pepco witnesses testified that these increased costs were unrelated to Pepco's AMI system, but rather related to the deployment of Pepco's new billing system.[109] Witness Lefkowitz was explicitly asked whether these increased expenses were related to AMI, and she testified that "those expenses that are cited by [AOBA witness] Oliver are not related to AMI."[110]

Finally, OPC seeks to re-raise the issue of whether limiting post-year costs for the AMI regulatory asset is appropriate.[111] OPC concedes that we have already addressed this issue in our order on rehearing in Case No 9406. In that order, we concluded that BGE could "defer post-test year smart grid costs in new smart grid regulatory asset so that it may properly seek recovery in a future base rate proceeding."[112] Although that decision is on appeal, we see no reason to re-visit our ruling at this time.

Cost Overruns

Mr. Hurley identifies several instances in which Pepco seeks recovery for AMI-related costs that are notably higher than originally estimated in Pepco's Application in

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107 *Id.*
108 Faruqui Rebuttal at 9.
109 Lefkowitz Rebuttal at 10; VonSteuben Rebuttal at 39-40.
110 Tr. 327 (Lefkowitz).
111 Effron Direct at 5. (Testifying that the AMI regulatory asset should only include the deferred costs as of the end of the test year).
112 Order No. 87951 at 10; OPC Initial Brief at 11.

Case No. 9207, and the metrics that Pepco has been providing to Staff on a quarterly basis.[113] Overall, Mr. Hurley testified that Pepco "exceeded its expected forecast for capital cost for meters, communications infrastructure and IT by close to 20% ($161 million in actual spending vs. a forecast of $135 million)".[114] These costs overruns included:

> 1) increased labor costs: Pepco attributes these cost overruns to "increased time required to install transformer-rated meters as well as to perform remediation work for non-communicating meters";[115]
>
> 2) Communication network costs: These costs exceeded forecast primarily because the Communications network required 15,748 more communication devices (an increase of 300%) than projected. Pepco claims that PHI determined that these additional devices were needed for the security of the system.[116]
>
> 3) IT costs: Pepco exceeded its forecast IT costs by 38%. These overruns were attributed to cybersecurity. Specifically, Pepco installed Utility IQ Critical Operations Protector ("COP") which are hardware security modules that provide fail safe mechanisms for critical commands. The $3.9 million overrun breaks down as: $3.0 million for UIQ software and hardware and $.9 million for COP software and hardware.[117]

Pepco contends that cost overruns are not per se imprudent,[118] and the record contains no evidence that these particular overruns were imprudent.[119]

While it is true that cost overruns are not *per se* imprudent, and we will not disapprove these overruns (with one exception, discussed below), the Commission depends upon the accuracy of project estimates, or we lack any foundation upon which to

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[113] Hurley Direct at 12; See also Ex. DJH-2, Hurley Direct at 50-51.
[114] Hurley Direct at 12.
[115] Lefkowitz Rebuttal at 6.
[116] Tr. 403 (Lefkowitz)
[117] Ex. DJH-2, Hurley Direct at 50-51.
[118] Pepco Initial Brief at 10-11; Lefkowitz Rebuttal at 5-6 ("[B]udget or forecasted target is an estimate based on facts known at the time, and spending more than budget is not per se imprudent.")
[119] Tr. 1600 (Hurley) ("You would agree with me, would you not, Mr. Hurley, that Staff has not proposed any adjustments to the specific AMI project for imprudence or cost overruns or the like; isn't that correct? Hurley: No, we have not.")

determine whether or not a proposed project should be approved to go forward. We understand that utilities cannot always estimate future costs with perfect accuracy, and we don't intend to subject good-faith estimates to unreasonable second-guessing, but when we rely upon estimates in approving a project, we do expect the estimates to be within a reasonable margin of error. The overruns that Mr. Hurley identifies are significantly higher than projected and, in future cases, we will more closely analyze similarly higher-than-forecast costs very closely

We disallow the cost over-run identified in Confidential Commission Exhibit 4. Pepco provided no basis upon which to recover these cost overruns. This is particularly so because the company recovered some portion of these cost overrun funds from the vendor but made a management decision to allocate only a small portion of the funds returned from the vendor to Pepco Maryland customers. We can see no basis upon which to require Pepco's Maryland ratepayers to absorb these cost overruns that were not returned to Pepco Maryland customers. Due to the confidential nature of the exhibit, we will only state that we disallow those expenses that were above the company's estimate, excepting that portion allocated to Pepco Maryland electric distribution.

Metrics

In Order No. 83571, we directed Pepco to provide Staff with detailed metrics, including incremental costs and benefits, budgets, performance of the AMI system, cybersecurity and other important aspects of the operation of the AMI system to allow Staff to monitor the performance of Pepco's AMI system.[120] Ms. Lefkowitz testified that

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[120] Order No. 83571 at 54 and Ordering Paragraph 5.

Pepco has complied with these reporting metrics, and no party has claimed otherwise.[121] We ordered BGE to continue to provide these metrics going forward in Case No. 9406.[122]

OPC requests, and we agree, that Pepco continue to submit these reporting metrics to Staff going forward.[123] We therefore order that Pepco do so, and we will closely follow the data therein to ensure that Pepco's AMI system continues to provide value to its Maryland ratepayers.

B. <u>Rate Base and Operating Income</u>

Rate base represents the level of net investment the Company makes in plant and equipment in order to provide safe and reliable electric service to its customers. Operating income is derived based upon the revenues the Company receives for electric service minus the costs it incurs in providing service to customers. The parties have proposed various adjustments to the Company's unadjusted rate base and operating income during the test year. We have reviewed the record and accept the uncontested adjustments proposed by the Company. The undisputed portion of the rate base for the uncontested adjustments, is $7,659,000. The undisputed portion of operating income uncontested adjustments, is $9,380,000. The parties dispute certain proposed rate base and operating income adjustments and we resolve these issues below.[124]

1. <u>RMA 1-4: "Reliability Plant" Additions</u>

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[121] Lefkowitz Direct at 7 – Mail-Log #s: 131260, 133571, 143602, 143602.
[122] Order No. 87591 at 66-67.
[123] Chang Direct at 3.
[124] *See* Appendix I for the Commission's calculation of the appropriate rate base and overall revenue requirement for rate making purposes; and Appendix II for operating income.

Safety and reliability are a foremost concern when we consider rate requests by utilities. In recent rate proceedings, the Commission has recognized that under appropriate circumstances, and when properly supported, adjustments to the historically accepted average test year may be warranted for safety and reliability investments and expenses, provided such investments or expenses do not generate additional utility revenues. Non-revenue producing safety and reliability investments, which we discuss in this section, generally serve existing customers rather than support new customers, which result in incremental utility revenues.

a. Parties' Positions

Pepco proposes four reliability ratemaking adjustments (RMAs). First, Pepco proposes RMA 1, which annualizes the effect of reliability projects that were added to Electric Plant In Service (EPIS) during this test period.[125] Pepco witness Mr. VonSteuben explained that this adjustment "reflects in EPIS the full value of those reliability projects added to plant, reduces [Construction Work In Progress] CWIP to the extent the projects were reflected in unadjusted test-year amounts, and removes actual retirements from both EPIS and accumulated depreciation.[126]

Second, Pepco proposes RMA 2 which adds to rate base those reliability projects that were placed in EPIS from January 2016 through August 2016, and for which actual data was made available prior to the evidentiary hearings.[127] Mr. VonSteuben argued that inclusion of RMAs 1 and 2 is consistent with similar RMAs proposed by Pepco in

[125] VonSteuben Direct at 13.
[126] VonSteuben Direct at 13.
[127] *Id.* at 13.

Commission Case Nos. 9286, 9311 and 9336, and with a similar RMA previously accepted by the Commission in Delmarva Power Case No. 9192.[128]

Third, Pepco proposes RMA 3 which "reflects the impact of known reliability projects in CWIP at the time of the hearings and that are forecasted to be placed into service from September 2016 to October 2016, prior to the rate effective date in (mid-November 2016)."[129] VonSteuben testified that these projects are not revenue generating and will be providing service to customers and placed into service for accounting purposes prior to the rate effective period commencing. VonSteuben also argued that "[i]nclusion of these projects is consistent with the Commission's decision on RMA 2 in Case No. 9336, where the Commission noted that it considered and included in rate base projects that were 'known and measureable.' "[130]

Last, Pepco proposes RMA 4 which "reflects the impact of the cost of additional known reliability projects that are forecasted to be expended prior to the rate effective date, providing service to our customers and will be placed into service for accounting purposes by year end December 2016."[131] VonSteuben argues that these projects will be providing service to Pepco customers the entire rate effective period and to not include them in the cost of service distorts the relationship of customers paying for services they are receiving.[132]

Generally speaking, the other parties addressing the reliability adjustments support Pepco RMA1 and RMA2. However, Staff witness Shelton noted that Staff reviewed the reliability projects included in RMAs 1 and 2 and identified several projects

[128] *Id.* at 13.
[129] *Id.* at 14.
[130] *Id.* at 15.
[131] *Id.* at 15.
[132] *Id.* at 15.

that did not appear to be related to reliability and as a result recommends that these projects be removed from RMA 1 and RMA 2.[133] Witness Shelton testified that Pepco was originally asked about these projects included in RMAs 1 and 2 on June 6, 2016 in a Staff Data Request No. 16-1. Specifically, Staff asked the Company to provide a detailed explanation of how those identified projects are reliability related. The Company response to Staff Data Request No. 16-1 stated "[a]ll of the replacement work is part of the overall reliability efforts. Physical security refers to the security the substation while work is being conducted." Ms. Shelton in her Surrebuttal noted that the Company failed to adequately respond to the inquiry initially and provided an update to the data request on August 10, 2016, which still did not clarify the nexus between these projects and reliability.[134] Ms. Shelton testified that Staff reassessed its review of the identified projects in light of the new information provided by the Company and found that the projects in question were never identified as reliability initiatives listed in Case Nos. 9240, 9361 or 9353.[135] Therefore, Staff continues to recommend these projects be removed from RMA 1 and RMA 2. In her Surrebuttal, Ms. Shelton noted that Pepco had provided updated cost data for RMA 1 and RMA 2. As a result of the updated cost data, Staff recalculated its reduction for RMA 1 and proposed that the reduction should be $471,122 instead of $1,891,091. Similarly, Staff modified its recommendation to reduce RMA 2 by $291,000 instead of $572, 000.[136]

[133] Ms. Shelton identified the following projects for removal from RMA1 and RMA2: "all street light related projects; replacement substation roofs; replacement of manhole roof; physical security of the substation; alarm cable replacement; Beckwith controller replacement; substation ventilation; and removal of poles/transformers/street light heads. Along with these Staff also removed an unidentified blanket project, capital storm restoration, and AMI field deployment due to insufficient information." Shelton Direct at 19.
[134] Shelton Surrebuttal at 2- 5.
[135] Shelton Surrebuttal at 3.
[136] *Id*.

OPC witness Effron did not propose similar adjustments to either RMA 1 or RMA 2. However, he made clear in his Surrebuttal that Pepco witness McGowan mischaracterized his proposed adjustments to the Company's reliability plant additions between 2015 and 2016. He testified that he does not recommend a blanket reduction of post test year reliability spend.[137]

Pepco witness Gausman rebutted Ms. Shelton's assertion that the eight projects identified above were not reliability related. He testified that "each of these activities is necessary to provide for the continued safe and reliable operations of the distribution system. Several of these projects would result in significant damage to substation equipment if this work was not performed and customers would be exposed to extended outages and increased cost."[138] Mr. Gausman's testimony then proceeded to provide a detail explanation of the eight projects and how they relate to reliability. Further, Mr. Gausman argued that "Pepco's actions relative to these projects were prudent and necessary to maintain a safe and reliable distribution system. In fact, it would have been irresponsible to forego performing this work and expose the distribution system to risk of additional damage as well as exposing customers to extended outages and safety hazards."[139]

Ms. Shelton did not dispute Mr. Gausman's assertion that these projects are needed to help maintain a safe and reliable distribution system. Rather, Ms. Shelton on cross examination stated that she was attempting to draw a distinction between reliability spending and just regular maintenance.[140] Specifically, Ms. Shelton stated that "It is my

[137] Effron Surrebuttal at 2.
[138] Gausman Direct at 3-4.
[139] Gausman Direct at 9.
[140] TR 1252:L1-6

opinion that reliability spending should upon completion have a direct impact on reliability, even a measurable impact on reliability."[141] Ms. Shelton on cross examination agreed that the eight projects identified may have an indirect impact on reliability but "should not be afforded the special treatment that's afforded reliability for rate-making adjustment items."[142] Moreover, Ms. Shelton clarified on cross examination that her "testimony does not disallow these items from going into rate base. It simply disallows the special treatment afforded to reliability rate-making adjustments."[143]

Regarding RMA 3 and RMA 4, Staff witness Ostrander stated that both RMA 3 and RMA 4 are considered not known and measurable, and these adjustments should be denied.[144] Mr. Ostrander provided four primary reasons he believed the Commission should reject Pepco's RMA 3 and RMA 4. First, he argued that "[t]he Commission has historically rejected these types of estimated/projected post hearing reliability plant additions adjustments in prior applicable rate cases."[145] Second, for this specific case, consistent with prior Commission decisions, the estimated/projected amounts are not known and measurable.[146] Third, the estimated/projected amounts are not shown to be used and useful.[147] Fourth, Pepco has not provided any new or compelling substantive and meaningful arguments or documentation to justify a departure from consistent prior Commission decisions in the past that have rejected these types of adjustments.[148]

OPC witness Effron testified that the Company's Adjustments 3 and 4 recognize reliability related plant additions after August 2016 and do not meet the Commission's

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[141] TR 1252: L6-9; TR 1267:L4-9.
[142] TR 1267;L4-9 and 17-22
[143] TR 1270 L23 – 1271 L1-4.
[144] Shelton Direct at 19.
[145] Ostrander Direct at 13.
[146] *Id*.
[147] *Id*.
[148] *Id.*

known and measurable standards for inclusion in rate base. Mr. Effron noted that in Pepco Case No. 9336, the Company proposed virtually identical adjustments to its test year base rates to recognize post-test year plant additions. However, in that case the Commission found that the proposed adjustments was "not known and measurable, nor does it represent actual spending, which is a requirement to be included in rate base."[149] Therefore, Mr. Effron argued that RMA 3 and RMA 4 in the present case should be eliminated.[150]

b. <u>Commission Decisions</u>

In Pepco's most recent rate cases, Case Nos. 9311 and 9336, the Commission has accepted similar RMA 1 and RMA 2 adjustments for reliability plant additions for the test period and actual reliability investments for the post test period. We primarily have accepted these adjustments when the Company demonstrated that such investments meet objective standards for safety and reliability, have not generated additional utility revenues, and will provide service to existing rather than new customers.

As noted by Pepco, most of the parties agree with the vast majority of its reliability investments in RMA 1 and RMA 2. However, Staff Witness Shelton recommends a reduction to RMA 1 and RMA 2, arguing that for some projects the Company did not provide adequate information to show that they were reliability related. Further, we note that, while Mr. Gausman provided further explanation about how each of the eight projects related to reliability, the Company could not demonstrate how implementation of these projects had a measurable impact on reliability. Staff witness Shelton rightly points out that these projects as presented in this proceeding appear to

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[149] Effron Direct at 4.
[150] *Id.* at 4.

involve regular maintenance and should not be afforded the special ratemaking treatment afforded reliability projects with measurable impact.

Considering Staff witness Shelton recommendation in relation to Commission practice for approving reliability plant additions, we accept Staff's recommendation of reducing RMA 1 by $471,122.

With respect to post test period reliability investments proposed in RMA 2, we will allow the inclusion of three months (January 2016 to March 2016) of post-test period reliability plant additions associated with RMA 2. Allowance of post-test period reliability expenses is an exception to the rule of allowing recovery only of reliability investments for historical test period. This exception was adopted several years ago as an attempt to incentivize the Company to make accelerated reliability infrastructure investments by allowing recovery of the expenses without waiting for another rate case. The Commission stated previously that it "departed from traditional ratemaking principles"[151] due to Pepco's poor reliability performance over the prior decade[152] and did not intend for this exception to become deemed as guaranteed or automatic. Thus, the Commission adopted in May 2012 comprehensive electric reliability regulations in COMAR 20.50.12.02 (also referred to as RM 43), which provides specific SAIDI and SAIFI standards intended to result in annual reliability improvements.[153]

In the present proceeding, Pepco witness Gausman testified to the tremendous improvements made in reliability such that the Company now meets or exceeds its SAIFI and SAIDI requirement. He noted that in 2015, customers experienced an improvement

[151] Case No. 9311, Order No. 85724 at 2
[152].Case No. 9240 Order No.84564
[153] Case No. 9311, Order No. 85724 at 2.

of 46% in SAIFI and 43% in SAIDI when compared to 2011 performance.[154] He further stated, "[o]ur continued investment in people and strengthening the electrical infrastructure and employing innovative technology has contributed to a historical best performance in both SAIDI and SAIFI for 2015."[155] Given Pepco's improved performance and in light of the significant increase in rates the Company is requesting, we no longer find that Pepco needs this reliability exception in whole. Therefore, our allowance of the three months of post-test period reliability investments for RMA 2 is reduced by the acceptance of Staff's reduction for the projects that do not impact the Company's reliability which generates a revenue requirement of $7,227,000.

Several parties have pointed out that RMA 3 and RMA 4 do not meet the Commission's standard for known and measurable and the reliability plant additions being proposed are not currently used and useful for the benefit of current customers. In keeping with our historical treatment of similarly proposed adjustments, we reject the Company's proposed RMA 3 and RMA 4 which reduces Pepco's revenue requirements by $2.1 million and $4.2 million, respectively.

2. <u>RMA 6: Incremental Costs Associated with Pepco's AMI's Deployment</u>

a. <u>Parties' Positions</u>

In Case No. 9207, the Commission stated that "at the time the Company has delivered a cost-effective AMI System, the Company may seek cost recovery in a base rate proceeding."[156] Pepco is seeking recovery of $97.2 million of capital investments

[154] Gausman Direct at 4.
[155] Gausman Direct at 4.
[156] Order No. 83571. See also McGowan Direct at 7.

that it made in AMI meters, communications equipment and other assets through rate base.[157] Additionally, the Company is seeking recovery of its $60.9 million regulatory asset that was established to defer various costs associated with its AMI system pursuant Order No. 83571.[158] Pepco witness VonSteuben proposed RMA 6 to recover its deferred AMI costs in rate base. "The deferred costs include: AMI-related incremental depreciation expense, AMI and Dynamic Pricing-related deferred Operation and Maintenance (O&M) expenses, AMI O&M Savings, as well as AMI and Dynamic Pricing-related deferred returns."[159] In addition to the AMI deferred costs in the regulatory asset, RMA 6 reflects ongoing AMI O&M and depreciation expenses that should be included in the Company's cost of service in the rate effective period.[160] In his rebuttal testimony, Mr. VonSteuben noted that the Company presented the deferred AMI balances into four timeframes: a) from inception through December 2015 (end of the test year); b) from January 2016 to June 2016; c) from July 2016 to August 2016; and d) from September 2016 to October 2016.[161] Mr. VonSteuben noted that the financial data for timeframes A through C was known and measurable at the time of the hearings.[162]

Mr. VonSteuben testified that Pepco is seeking recovery of $3,818,000 of ongoing O&M, savings and depreciation in RMA 6. He argued that recovery would be appropriate because the test year does not reflect these expenses due to AMI-related costs/savings being deferred under Commission Order No. 83571.[163] The Company, although initially requested AMI deferred regulatory asset recovery on a 5-year

[157] McGowan Direct at 7.
[158] *Id.*
[159] VonSteuben Direct at 16.
[160] *Id.*
[161] VonSteuben Rebuttal at 29-30.
[162] VonSteuben Rebuttal at 30.
[163] *Id.*

amortization basis, agreed with Staff Witness Ostrander and OPC witness Effron to change the proposed amortization period from 5 to 10 years.[164]

Staff Witness Ostrander in his Surrebuttal stated that to be consistent with the Commission's Errata Order No. 87591 in the recent BGE rate case[165], he has disallowed Pepco's post-test year AMI Regulatory Asset costs. However, Mr. Ostrander does acknowledge that "Pepco is allowed to seek recovery of these same costs in a 'future' deferred AMI Regulatory asset cost established after this proceeding."[166] Specifically, Mr. Ostrander points out that the Commission's Rehearing Order in Case No. 9406 modified the original Errata Order by recognizing "that recovery of these costs as future expenses may be more expensive to ratepayers than allowing such costs to be set up in a future regulatory asset and subject to amortization over a period of years. Therefore, the Commission's Rehearing Order allows these costs to be set up in a future regulatory asset so that Pepco may seek recovery of these costs in a future rate case (although recovery is not guaranteed)."[167]

Regarding the treatment of the post-test year costs related to AMI Ongoing Expenses/Savings, Mr. Ostrander stated that in his direct testimony he had proposed removal of all post-test year Ongoing Expenses/Savings because he was unable to determine how the Commission specifically treated those costs in the BGE Case No. 9406.[168] In his surrebuttal, Mr. Ostrander acknowledged that in the Commission's Errata Order in BGE Case No. 9406, the Commission had allowed AMI Ongoing Expense post-

[164] *Id.* at 32. The 10-year amortization period is consistent with the Commission's decision in BGE Case No. 9406. *See* VonSteuben Rebuttal at 33.
[165] Ostrander Surrebuttal at 10. Commission Errata Order No. 87591, BGE CN 9406, issued June 3, 2016, pp. 70-71.
[166] Ostrander Surrebuttal at 15.
[167] *Id.* at 15-16.
[168] Ostrander Surrebuttal at 17.

test period costs in the BGE Case No. 9406.[169] Mr. Ostrander thus agreed to accept Pepco's Ongoing Expense/Savings; however, in his surrebuttal testimony, Mr. Ostrander stated that he would deny approximately $2.5 million of those net expenses because Pepco failed to provide adequate supporting documentation and calculations to support most of its AMI ongoing expenses. He would allow actual test period ongoing expenses of $44,021 and ongoing depreciation expenses of $1,265,913, but he would disallow the remaining $2,508,066 not specifically identified by the company."[170]

b. Commission Decision

Consistent with our decision in BGE Case No. 9406, we reject Pepco's adjustment to include post-test year AMI Regulatory Asset costs in rate base and instead adopt Staff's and OPC's position to remove post-test year AMI costs from rate base and place them in a new regulatory asset for potential recovery in a future base rate proceeding.[171] We adopt for Pepco what we stated in that case about BGE's new regulatory asset, which is that the new regulatory asset is restricted to the post-test year AMI costs identified in the instant proceeding and that we reserve judgment on whether a return on this new regulatory asset is appropriately included, as such a burden is borne by the Company at the time it seeks recovery.[172] Also, we accept the parties' consensus position to adopt a 10-year amortization of the AMI regulatory asset. Regarding AMI Ongoing Expenses, we accept Mr. Ostrander's recommendation to remove certain net ongoing expenses due to inadequate supporting documentation. As with all items included in customer rates, the Company has the burden of proof to justify the level of

[169] Ostrander Surrebuttal at 18-19.
[170] Ostrander Surrebuttal at 20-21.
[171] Order No. 87695 at 10-11.
[172] Order No. 87695 at 10, FN 16.

recovery that it seeks. Here, it did not sufficiently demonstrate the actual amounts of net ongoing expenses for significant portions of the cost recovery requested, and so we deny that portion of the company's request as identified by Mr. Ostrander.

3. RMA 7: Legacy Meters

a. Parties' Positions

The Company's proposed RMA 7 amortizes the net book value of the retired legacy meters over 10 years.[173] Initially, the Company's adjustment included "a return on" the undepreciated value of the legacy meters. In his rebuttal testimony Mr. VonSteuben noted that, in light of the Commission's August 10, 2016 decision (Order No. 87710 in Case No. 9385), the Company withdrew its adjustment requesting a "return on" the unamortized legacy meters but it continued to support the use of a 10 year amortization period unlike the Commission's recent decision amortizing the undepreciated value of the legacy meters over 15 year period.[174] Pepco argues that the Commission approved a 10-year amortization of legacy meters in the BGE rate case, Errata Order No. 87591.[175] Additionally, Pepco notes that "[n]o party has presented any evidence as to why Pepco should be treated any differently" from BGE.[176] The Company also argues that allowing customers to repay the cost of the legacy meters over 15 years as opposed to 10 years with no return on the investment results in a higher financial cost to the Company.

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[173] VonSteuben Direct at 17.
[174] Case No. 9385, Order No. 87710, Petition for Rehearing pending.
[175] Pepco Initial Brief at 35.
[176] *Id*.

Staff, OPC, Montgomery County, and HCNCA support the Commission's decision to adopt a 15-year amortization period to recover the unamortized balance of the legacy meters. HCNCA pointed out that "the public Service Commissions of Delaware and the District of Columbia have authorized 15-year amortization periods for the regulatory assets associated with legacy meters."[177]

b. Commission Decision

We agree with the Company that, in general, we treat our utilities the same unless there are facts that support different treatment. In this instance there are no such facts to support treating Pepco differently than BGE. Accordingly, we adopt the Company's position to amortize the unamortized balance of legacy meters over 10 years.

4. RMA 9 and 10: Tax Compensation Carrying Costs and its Reversal

a. Parties' Positions

Pepco is an affiliate of Pepco Holdings, Inc. ("PHI"), and Pepco's financial results became part of PHI's consolidated tax return. In 2013, Pepco sustained tax losses that other members of PHI used to offset their taxable income. Payment from PHI for the 2013 tax losses was not received by Pepco until September 2014. In Pepco's last base rate case, Case No. 9336, the Commission would normally have reduced Pepco's rate base by the amount of the tax compensation payment it received from PHI. Pepco, however, received the tax compensation after the Commission issued its order in Phase I of Case No. 9336, and the Commission in Phase II required Pepco to accrue carrying costs on the reimbursement.[178] The carrying costs compensate ratepayers for the time

[177] HCNCA Initial Brief at 40.
[178] Case No. 9336, Phase II, *Potomac Electric Power Company*, Order No. 86711, November 13, 2014, at 26.

value of the tax compensation payment that was due but not paid at the time of the last base rate case.[179] The Commission's order explained this matter as follows:

> We conclude that the 2013 tax compensation payment Pepco received in September 2014 should be reflected in Pepco's next rate case, calculated consistent with the calculation of RMA 8 in this proceeding. In this way the payment can and will be reflected on a known and measurable basis. However, we will require Pepco to increase the adjustment by including carrying costs at its currently authorized overall rate of return from the date Pepco received the payment in September 2014 through the expected order date in its next base rate case whenever it is filed. In this way an accurate known and measurable adjustment can be made and customers will receive the full value of the tax compensation payment. Thus, customers will not be disadvantaged by the timing of Pepco's rate proceedings.[180]

Pepco calculated the required carrying costs from September 2014 through October 2016, when it expected the Commission's Order to be issued in the present base rate case. In RMA 9, Pepco has amortized the carrying costs over three years, resulting in an increase to the Company's pre-tax income in this case of $1,761,000. Pepco RMA 10 reversed the effect of RMA 9 and eliminated the carrying costs on the tax compensation payment.

In its Order in Case No. 9336, the Commission acknowledged Pepco's right to present "expert testimony and legal argument" that carrying costs should not be added to the adjustment for the tax loss compensation payment that the Company received from PHI members.[181]

[179] *See Healthcare Council of the National Capital Area*, Initial Brief at 39.
[180] Order No. 86711 (Nov. 13, 2014), p. 26 (footnotes deleted).
[181] *Id.*

In his direct testimony, Pepco witness McGowan challenged the Commission's order to pay carrying charges on the grounds that it constituted disfavored "single issue ratemaking,"[182] which, he claimed, the Commission "only ... considered because it provided a benefit to customers." The tax compensation payment received in 2014 was "singled out for ... a carrying cost," while state and local tax payments, Mr. McGowan stated, were made "over the same time frame" but not given any special treatment.[183] Further, witness McGowan asserted that carrying charges were imposed on Pepco only because of the date the tax compensation payment was paid.[184]

People's Counsel's witness Effron opposed Pepco's attempt to avoid the carrying charges imposed by the Commission in Case No. 9336, Phase II. Witness Effron argued that, as ratepayers have been paying a return on plant additions that gave rise to the net operating losses since Case No. 9336 went into effect, "it is reasonable to give the benefit of the return on those payments from the time they were received until the rates in the present case go into effect."[185] Therefore, witness Effron recommended elimination of Pepco's proposed RMA 10, which would reverse the effect of the carrying costs accrued. He also did not oppose amortizing the carrying costs.[186] OPC witness Effron also recommended that the Company provide to the Commission notice of the compensation it received for its 2015 NOLCs as soon as that number is known.[187]

Staff witness Ostrander also rejected RMA 10, and opposed Pepco's amortization of its carrying charges. He interpreted the Commission's Order in Case No. 9336, Phase

[182] McGowan Dir. at 20-21.
[183] *Id.*
[184] *Id.*
[185] Effron Dir. at 13.
[186] *See* Effron Dir. at 13-14.
[187] Effron Dir. at 13-14.

II as requiring ratepayers to receive the "full value" of the tax compensation payment Pepco received, without reference to the timing of Pepco's rate cases. Mr. Ostrander noted that amortization would cause delay in itself, and "that compounded carrying charges would need to be applied to the delayed carrying charges to again make sure that customers are not disadvantaged."[188] He also responded to Pepco's assertion that amortization of its tax loss reimbursement was appropriate due to tax loss reimbursement being rare, by noting that Pepco has been recording net operating losses (and thus tax losses) since 2012.[189]

Witness Ostrander would therefore increase carrying charge income by $3,169,000 to reflect the total amount of carrying charges through the end of the test period, December 31, 2015.[190] Witness Ostrander stated that should the Commission amortize the carrying charge over a number of years, "it will be necessary to set up a regulatory liability account to offset rate base and reflect the unamortized balance over the amortization period."[191]

In his rebuttal testimony, Pepco witness McGowan reiterated the Company's concern that the Commission's imposition of carrying costs on its tax loss reimbursement was single issue ratemaking. He maintained "that a utility's revenue requirement is based on the utility's aggregate costs, rather than on certain specific costs related to an isolated portion of its business."[192] Isolating Pepco's tax payments could also cause the

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[188] *Id.* at 44-45.
[189] Ostrander Rebuttal at 40.
[190] Ostrander Dir. at 43.
[191] *Id.* at 44.
[192] McGowan Rebuttal at 36-37.

Commission to ignore offsetting and therefore underestimate revenue requirements, Mr. McGowan claimed.[193]

Witness McGowan's rebuttal testimony also opposed Staff witness Ostrander's position that the tax payment should be credited to Pepco in one year. Witness McGowan argued instead that the Commission imposed carrying charges in order to mirror the actual tax compensation payments made to Pepco. As those payments are now known and measurable, according to witness McGowan, it does not matter if the Company records its carrying costs or not.[194]

Pepco witness VonSteuben, in his rebuttal testimony, contested Staff witness Ostrander's proposed one-year amortization of tax compensation carrying costs. "A 1 year amortization of an extremely high dollar amount ... would inappropriately provide the full credit to the customer until distribution rates are reset," according to witness VonSteuben.[195]

Witness McGowan also addressed Staff witness Ostrander's assertion that if the Commission rejected RMA 10 the Commission should also reject Pepco's position that the carrying costs should be amortized over three years. Amortization is appropriate, Pepco witness VonSteuben argued, "given the unusual and infrequent nature" of this ratemaking adjustment, and because of the high dollar amount of the adjustment.[196]

In his surrebuttal testimony, Mr. Effron stated that Mr. VonSteuben's arguments on rebuttal had not persuaded him that Pepco's accrued carrying costs should be eliminated. He reiterated that the Commission required Pepco to accrue carrying costs in

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[193] *Id.* l at 37.
[194] *Id.* at 37-38.
[195] VonSteuben Rebuttal at 35.
[196] *Id.*

Case No. 9336 "so that customers would receive the full value of the tax compensation payment and would not be disadvantaged by the timing of Pepco's rate proceedings."[197]

b. Commission Decision

No intervenor favored Pepco's position on this issue.

The Commission also sees no persuasive argument that it should essentially nullify the relevant section of its Order in Case No. 9336, Phase II and cancel Pepco's carrying cost accruals for tax loss reimbursements. The Commission rejects Pepco's argument that assignment of carrying costs in this context is single issue ratemaking. Tax reimbursement is simply one of many operating income issues the Commission must address in the course of a base rate case, approaches to the various issues necessarily differ, and assignment of carrying charges was a reasonable and necessary response to uncertainty about the amount of PHI's reimbursement to Pepco in 2013. Pepco has not pointed to any "offsetting considerations" that the Commission has missed by imposing carrying costs on Pepco's late tax reimbursements.[198] The Commission likewise sees no reason to amortize the carrying charge amount, as Pepco requests, as Pepco received the full benefit of PHI's payment at one time, and equal treatment of ratepayers is appropriate. The Commission also wishes to avoid the possibility, referred to in Staff witness Ostrander's testimony, that compounded carrying charges could become necessary.

Therefore, the Commission declines to accept Pepco's proposed RMA 10 and makes no change to its ruling on this issue in Case No. 9336 which accepts RMA 9.

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[197] Effron Surrebuttal at 8.
[198] *See* McGowan Rebuttal at 37.

5. RMA12: Pepco Employee Salary and Wage Increases

a. Parties' Positions

The Company proposed RMA 12 that adjusts O&M expense to annualize employee salary and wage increases which occurred in the test period.[199] Mr. VonSteuben explained that "during the test period, there was a 3.00% increase for management employees effective March 1, 2015 and a 2.50% increase for union/bargaining unit employees effective June 1, 2015."[200] Additionally, this adjustment reflects "wage increases of 2.40% for the March 1, 2016 management increase and the contractual 3.00% increase for bargaining unit employees effective June 1, 2016,"[201] which are for the post-test period. The Company argued that this adjustment was in keeping with a long-standing historical precedent for Commission approval of this adjustment beginning with Case No. 8315, and most recently approved an identical uncontested adjustment in Case No. 9336.

Staff witness Ostrander proposes to remove Pepco's two post-test year period pay increases that take place in 2016. Mr. Ostrander removed the amounts related to the 2.4% management pay increase effective March 1, 2016 and the 3% union pay increase effective June 1, 2016.[202] Mr. Ostrander testified that Pepco's pay increase adjustment does not make any offsetting reductions in payroll costs to reflect reductions in headcount and related payroll savings after December 31, 2015 for both merger-related savings and AMI-related savings.[203] Mr. Ostrander noted that Pepco's payroll increase adjustment was clearly not intended to reflect only an annualization of 2015 payroll, because if so

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[199] VonSteuben Direct at 20
[200] *Id*.
[201] VonSteuben Direct at 20.
[202] Ostrander Direct at 52-53.
[203] *Id.* at 53.

Pepco would have only included its two 2015 pay increases in its adjustment,[204] which Mr. Ostrander does not challenge. Here, Pepco also annualizes two payroll increases that take place in 2016.

HCNCA supports Staff's recommendation and argues that the Commission should reject both: 1)the two post test period pay increases because the Company failed to make any offsetting reductions in payroll costs to reflect reductions in headcount; and 2)related payroll savings after December 31, 2015 for both the merger-related savings and AMI-related savings.[205]

b. <u>Commission Decision</u>

Consistent with previous decisions, we accept annualization of wage increases that occurred during the test period ending December 31, 2015 and the post-test period proposed increase since they are known and measurable during the rate effective period. However, we caution the Company in future rate cases that it must provide more detailed documentation demonstrating that offsetting reductions in headcount and other related payroll savings were included in its wage adjustment.[206]

6. <u>RMA 15: Executive and Incentive Compensation</u>

a. <u>Parties' Positions</u>

The Company proposed RMA15 to remove from the test period all allocated executive incentive expenses such as the Executive Incentive Compensation Plan (EICP) and the Long Term Incentive Plan (LTIP) of the top five ("Top 5") Pepco Holding executives as well as the EICP and LTIP expenses related to financial goals of other executives. However, Mr. VonSteuben in his direct testimony stated that the Company

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204 Ostrander Surrebutal at 46.
205 HCNCA Initial Brief at 43.
206 Order No. 87591 at 70, FN 314

disagrees with this adjustment because retention of talented and qualified top level executives is an important component of the Company's total executive compensation and are likely to continue to be so in the future.[207] In his rebuttal testimony, Mr. Von Steuben elaborated that with this adjustment "the Company removes $2.9 million expense of related to the named executives and $1.9 million related to financial goals."[208] Therefore altogether, the Company was removing $4.8 million in RMA 15[209] which Mr. VonSteuben stated would result in $2.5 million remaining in cost of service associated with customer-focused goals.[210] The Company thus noted that it reserves the right to seek recovery of these costs in future rate case filings.[211]

Staff witness Ostrander acknowledged that the Company removed $3 million of incentive expenses related to the financial goals of the Top 5 Pepco Holding executives as well as other executives. However, in addition, to Pepco's adjustment, Mr. Ostrander recommends removing an additional $1,559,531 and contends that Pepco is unable to prove that amount is tied to either financial-related or customer-focused goals.[212] Mr. Ostrander further explained that "the purpose for this adjustment is to remove incentive compensation costs that reward executives for achieving certain financial-related goals that do not provide specific quantifiable measurable benefits to customers."[213] Mr. Ostrander pointed out that Staff DR 20-6 asked the Company "to explain and provide calculations that show executive incentive costs allocated between " 'financial-related' goals and criteria and 'non-financial related/customer-focused' goals and criteria and

[207] VonSteubent Direct at 21.
[208] VonSteuben Rebuttal at 45.
[209] *Id.*
[210] VonSteuben Rebuttal at 45.
[211] VonSteubent Direct at 21.
[212] Ostrander Direct at 59.
[213] *Id*.

reconcile these amounts with Pepco's proposed adjustment of $3,001,000 which is intended to remove incentive costs tied to financial-related goals and criteria." [214] Mr. Ostrander contends that Pepco failed to provide specific documentation that would show whether their recommended adjustment was the appropriate amount of incentive expenses tied to financial-related goals.

Pepco witness Mr. VonSteuben stated that the Company agreed that costs related to financial goals should be removed. Additionally, the Company agrees that costs related to customer-focused goals should be included in the Cost of Service.[215] Mr. VonSteuben further identified the customer-focused goals include: Affirmative Action; Customer Satisfaction; Reliability; Capital Spend; NERC Compliance; and LTIP Time-based Goal.[216] Mr. Ostrander did not refute these categories as being customer-focused.

Nonetheless, Mr. Ostrander points out that even in Mr. VonSteuben's rebuttal testimony he continued to rely on the Company's response provided in Staff DR 20-6 without adding any information.[217] Therefore, Mr. Ostrander stated that he does not propose any revisions to his adjustment to reduce the Company's proposal by $1,560,000.[218]

HCNCA supports Staff's adjustment and proposed that "the Commission should direct Pepco to remove an additional $1,559,531 from incentive expenses that Pepco has failed to demonstrate are tied either to financial related or customer-focused goals."[219]

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[214] *Id*.
[214] *Id*.
[215] VonSteuben Rebuttal at 44.
[216] *Id*.
[217] Ostrander Surrebuttal at 52.
[218] *Id*. at 51.
[219] Healthcare Council of the National Area Initial Brief at 45.

HCNCA further noted that removal of the $1,559,531 would be consistent with the executive costs removed in Case Nos. 9311 and 9336.[220]

b. Commission Decision

The Commission has recognized in Case No. 9311 that both the Company and ratepayers benefit from the qualified executives the Company attracts and retains through its executive incentive compensation packages. However, we believe that the Company should only be allowed to recover non-financial-related goal expenses to the extent that the Company can demonstrate that they provide benefits to Maryland ratepayers. Here the company proposed RMA 15 which reduces its revenue requirement by approximately $3 million which Pepco found to be related to financial goals of the Top 5 executives as well as the financial goals for the remainder executives. Staff argues that an additional $1.6 million should be reduced because the Company did not provide additional support documentation to show these expenses were customer-focused related. We find in Staff DR 20-6 that the Company did provide sufficient documentation delineating financial related expenses of the Top 5 as well as the other Company executives. Additionally, the Company identified the non-financial customer-focused goals and described the percentage of payouts. Therefore, we accept the Company's proposed adjustment RMA 15 that reflects a reduction in the Company's proposed revenue requirement of $3,067,000.

7. RMA 16: Supplemental Executive Retirement Program

a. Parties' Positions

The Company proposed RMA 16 to reflect a 50% reduction of the Pepco's Supplemental Executive Retirement Plan (SERP) expense incurred during the test period.

[220] *Id*.

To support this adjustment, Mr. VonSteuben cited Order No. 86441 from Case No. 9336 where the Commission accepted Staff's recommendation to disallow 50% of SERP and found that "shareholders and ratepayers both benefit from the highly qualified executives the Company says it uses SERP to attract and retain."[221] Mr. VonSteuben noted that the Company continues to disagree with any level of reduction in SERP but nonetheless offered this adjustment to be consistent with Commission precedent.

Staff witness Ostrander recommended that the Commission should remove 100% of the SERP costs and testified that there are now some new circumstances and facts to support his recommendation. First, Mr. Ostrander noted that although the Commission has adopted the 50% disallowance in Pepco's two most recent cases it acknowledged in Case No. 9336 that appropriate funding for SERP costs continues to be an evolving issue to be reviewed in future cases.[222] Second, Mr. Ostrander points out that executive and management incentive payments have increased substantially in the past two years compared to three years ago and are having an increasingly significant impact on revenue requirements.[223] Third, Staff DR 22-6 asked several questions for the Company to explain how either a 50% reduction in SERP costs in the Maryland jurisdiction or 100% removal of SERP in the Pepco's DC and Delaware jurisdictions negatively or adversely impacted the Company's ability to attract or retain executives. The Company's response merely asserts that "[m]ost peer utility companies offer SERP benefit, so it is important that Pepco offers a comparable compensation and benefit package." But the Company does not provide specific documentation to support its assertion. Pepco's response noted that "to date, the Company has not performed any analysis on how employees or new

[221] VonSteuben Direct at 22.
[222] Ostrander Direct at 62.
[223] *Id*.

recruits would react if certain benefits were offered by our competitors and no longer offered by Pepco."[224] Fourth, two neighboring jurisdictions, DC and Delaware have disallowed 100% of SERP costs. Fifth, Mr. Ostrander argues that SERP only benefits a small group of key executives and Pepco has not provided documentation to quantify any measurable benefit to customers from SERP.[225] Last, Mr. Ostrander argued that the Commission should apply the same focus – in the present proceeding - of taking measures to "ease rate shock to the fullest extent possible when it adopted a 10-year amortization of the AMI-related regulatory asset" as it did in BGE Case No. 9406 and disallow 100% of SERP in Pepco's Maryland jurisdiction.

HCNCA agreed with Staff that Pepco had not provided sufficient documentation to demonstrate that SERP-related payments to executives have provided quantifiable benefits to its Maryland customers. Therefore, HCNCA argues that Pepco's failure to provide sufficient documentation, coupled with recent decisions by DC and Delaware Public Service Commissions to disallow 100% of Pepco's SERP recovery, should cause the Commission to take a harder look at SERP.[226]

b. <u>Commission Decision</u>

Although the Company may be correct in noting that the Commission has disallowed 50% of SERP expenses in Pepco's two most recent cases, we find that Staff has astutely pointed out that there are some new circumstances to be considered. Most significantly, we find it telling that, after two neighboring jurisdictions recently disallowed 100% of Pepco's related SERP costs for DC and Delaware, the Company has

[224] Ostrander Direct at 62 citing Staff DR 22-6.
[225] *Id*. at 62.
[226] HCNCA Initial Brief at 45-46.

not performed any analysis to support its continued claim that SERP benefits help the Company to attract and retain qualified executive level talent.

In the present proceeding, Staff DR 22-6 set forth several questions in light of this changed circumstance to elicit more detailed information from Pepco to support recovery of SERP. However, as noted above, the Company failed to offer additional documentation or quantifiable information supporting its position and even responded that it had not performed any analysis on whether if it could retain or attract qualified key executives if Pepco no longer offered SERP as part of its executive compensation package. Therefore, given that the Company has not met its burden of proof and in light of similar action taken in DC and Delaware, we accept Staff's recommendation to disallow 100% SERP expenses.

8. <u>RMA 23: Winter Storm Pax</u>

a. <u>Parties' Positions</u>

The Company proposes RMA 23 which amortizes over five years the expenses for the February 2014 Winter Storm PAX preparation costs.[227] Mr. VonSteuben testified that this is consistent with the treatment of 2013 Winter Storm Preparation Costs in Case No. 9336 where the unamortized balance is included in rate base.[228]

Staff witness Dodge noted that to support Winter Storm PAX, PHI requested 400 Full Time Equivalents ("FTE's") and only received 303 FTEs. Forty FTE's were deployed in the Pepco region.[229] Mr. Dodge recommended that the allocated mutual assistance costs for the Pepco Region be reduced from 67.11 % to 13% which he calculated by dividing the 40 FTEs deployed to the Pepco Maryland Region by the total

[227] VonSteuben Direct at 23-24.
[228] *Id*.
[229] Dodge Direct at 4.

number of mutual assistance resources secured (303 FTEs).[230] He argued that the remaining costs should be allocated to the other PHI affiliates that benefited from the use of the resources. Mr. Dodge also recommended that estimated storm costs of $120,149 for Winter Storm PAX should be excluded from the amount of expenses that the Company is allowed to recover. Last, Mr. Dodge recommended that Pepco should file for review and approval by the Commission, a copy of its process and procedures for tracking, verifying, auditing and processing external mutual assistance crews and associated costs.[231]

The Company argued that the costs represented in Winter Storm Pax "are no different from the costs for the March 2013 Nor'easter that were approved in Order No. 86441. Like Winter Storm Pax, the March 2013 Nor'easter ultimately did not affect the Pepco service territory."[232] Here they point out that "the Company's method for allocating storm preparation costs for storms (like Pax and the March 2013 Nor'easter) that ultimately do not affect the Pepco region is a ratio based on the number of Pepco Maryland customers relative to the total number of customers in the entire Pepco region."[233] The Commission approved the allocation method in Case No. 9336.

b. <u>Commission Decision</u>

We have reviewed the testimony and evidence presented and find that Pepco followed its approved procedures and processes for storm preparation during Winter Storm PAX, which included using weather forecasts from two outside weather services, considering the fact that the Governor had issued a State of Emergency in advance of

[230] *Id*.
[231] *Id*. at 6.
[232] Pepco Initial Brief at 48-49.
[233] *Id*. at 49.

Pax, and participating as a member of multiple mutual assistance organizations to identify its need for assistance.[234] For these reasons, coupled with the fact that Winter Storm Pax was similar to the March 2013 Nor'easter, the Commission accepts Pepco's RMA 23.

9. RMA 24: Winter Storm Jonas

a. Parties' Positions

Consistent with the treatment of 2013 Major Storms Preparation costs in Case No. 9336, the Company recommended RMA 24 which defers and amortizes over five years the expenses incurred for January 2016 storm (a.k.a. "Winter Storm Jonas") costs.[235] Pepco witness Gausman testified that the Company incurred costs in the preparation for Winter Storm Jonas which was forecasted to severely impact Pepco service territory.[236] He noted that prior to the storm Governor Hogan issued an Executive Order declaring a state of emergency on January 21, 2016 and therefore the Company began storm preparedness activities, including obtaining external resources of 1,057 personnel and 345 vehicles and internal resources of 1,035 personnel and 260 vehicles.[237] Mr. Gausman stated that Pepco was seeking to recover the incremental costs of bringing mutual assistance crews to the area, housing and feeding those crews and sending them back to their local companies.[238]

Staff witness Dodge reviewed Pepco winter storm Jonas adjustment and raised several concerns. First, he testified that "Pepco received 315 FTE's but did not deploy any of the resources to the Pepco region, yet assigned 47.6 % (49.6%) of the costs for the

[234] Dickerson Direct at 22-26.
[235] VonSteuben Direct at 24.
[236] Gausman Direct at 22.
[237] *Id*.
[238] Gausman Direct at 23.

external resources to the Pepco region."[239] Second, Mr. Dodge noted that even though Winter Storm Jonas occurred in January 2016, the Company was still processing invoices and using invoice estimates in its revenue requirements. For instance, Pepco had indicated in Staff DR 18-11 that its Rokstad invoice was in the process of being paid and that the Emera-Maine invoice for a $246,400 was still pending.[240] Last, Mr. Dodge expressed concerns about Pepco's ability to provide comprehensive tracking, invoicing and reconciliation processes. Mr. Dodge recommended that Pepco's allocation of mutual assistance costs should be reduced from 47.6% (49.6%) to 0% and if the Company is allowed to recover any storm invoice costs then the Commission should direct it to develop and file for review and approval a methodology for equitably assigning mutual assistance costs in its service testimony.[241] In addition to the arguments made by Mr. Dodge for removing costs associated with Winter Storm Jonas, Mr. Ostrander pointed out that "an argument could be made to remove all of the 2016 post-test period related costs of Jonas storm because they are post test period and do not meet the historical test period concept.[242]

b. <u>Commission Decision</u>

Pepco rightly noted that Winter Storm Jonas was classified as a major storm and it had an impact on the region.[243] The costs incurred and deferred to the regulatory asset are similar to other major storms over the past couple of years such as the June 2012 Derecho and the October 2012 Hurricane Sandy.[244] The Commission approved storm costs in both

[239] Dodge Direct at 8.
[240] *Id*.
[241] *Id*. at 13-14.
[242] Ostrander Direct at 58.
[243] Pepco Initial Brief at 50.
[244] *Id*.

of these situations in Case No. 9311, Order No. 85724.[245] In the present proceeding, Pepco indicated that Governor Hogan had issued a state of emergency signaling to Pepco and other Maryland utility companies to begin preparation for a major storm, including securing mutual assistance from internal and external resources as well as other preparation activities. To minimize the impact of major storms like Winter Storm Jonas on Maryland customers, we find that recovery of Pepco's RMA 24 costs is appropriate and we therefore reject Staff's recommendation.

10. <u>RMA 25: Synergies and Costs to Achieve Merger</u>

a. <u>Parties' Positions</u>

On March 23, 2016, the Public Service Commission of the District of Columbia approved the merger between Pepco Holdings Inc. and Exelon Corporation and the merger closed shortly thereafter. "RMA 25 includes an estimate of Pepco Maryland's share of synergies relating to the Exelon-Pepco Holdings Inc. merger, net of its amortized Costs to Achieve ("CTA")[246] The Company proposed RMA 25 to represent a "reduction to test period O&M expense to reflect conditions expected to be present in the first year following the close of the merger."[247] The Company argues that in order for the customers receive benefits of merger-related savings that the Company plans to achieve during the rate effective period it must propose that the CTA be deferred and placed into a regulatory asset and amortized over five-years with the unauthorized balance in rate base.[248]

[245] *Id*.
[246] VonSteuben Direct at 24.
[247] VonSteuben Direct at 24.
[248] Pepco Initial Brief at 51.

In his rebuttal, Mr. McGowan stated that Pepco is committed to passing 100% of all net merger-related synergy savings onto its customers.[249] He further notes that the model for passing on these savings was established by the Commission in prior rate cases following Exelon's merger with Constellation Energy and Pepco's treatment of merger-related synergies follows that established model.[250] Mr. McGowan testified that the Company's proposal takes the "year one" savings and costs-to-achieve from the established analysis to make an adjustment to the Company's current revenue requirement, leaving future year's savings and costs to achieve to be handled in future rate cases.[251] This results in initial savings being matched with costs to achieve those savings. To minimize rate increase in the initial period, Pepco proposes to amortize the year one costs to achieve over five years to ensure that customers receive a net benefit.[252]

Staff witness Ostrander recommended that $4 million of pre-close merger costs be removed from total merger costs of $22 million, to start with $18 million to be amortized over 5 years. Mr. Ostrander removed the $4 million because Pepco claimed that it did not incur any merger costs or savings prior to close of the merger transaction on March 23, 2016 and that it did not include any merger costs or savings in the revenue requirement of this case.[253] Additionally, Mr. Ostrander amortized total merger costs and savings over 5 years instead of using Pepco's approach to amortize merger costs over 5 years but only use Year 1 savings. Mr. Ostrander argued that his approach "ensures that customers will receive the same levelized amount of net savings regardless of whether

[249] McGowan Rebuttal at 48.
[250] *Id*.
[251] *Id*.
[252] *Id*.
[253] Ostrander Direct at 38.

Pepco does or does not file a rate case for the next 5 years…"[254] Staff claims that the Company's method, unlike its approach, "backend loads savings and frontloads costs, while Staff's approach will ensure that customers receive the same levelized…"[255] In his rebuttal, Pepco witness McGowan testified that Mr. Ostrander's proposal "is not based on any Commission precedent, excludes known and measurable costs and attempts to use all five years of estimated savings and costs to create a 'net regulatory asset.' "[256] Montgomery County agrees with Staff witness Ostrander "that it is reasonable to allow certain reasonable estimated merger costs and savings in the revenue requirement because there is no other good alternative that will provide some immediate and deserved benefit to customers as a result of the merger."[257]

OPC witness Effron also suggests a modification to Pepco's treatment of merger synergies and CTA. Basically, Mr. Effron's approach indicates that due to the timing of the close of the merger, i.e., March 23, 2016, the "Year 1" would end March 24, 2017. Since the rate effective year begins around November 1, 2016, the rate year will contain approximately five months of Year 1 merger-related synergies and seven months of Year 2 merger-related synergies. OPC noted that "[t]his treatment makes ratepayers responsible for all of the costs which pre-date the rate effective period, but does not credit the ratepayers with any of the savings accrued during the same period."[258] OPC criticized this approach as "unfair because the timing of the costs and savings are such that the costs are front-loaded while the majority of the benefits accrue in later years."[259]

[254] *Id*. at 39.
[255] Staff Brief at 14.
[256] McGowan Rebuttal at 49.
[257] Montgomery County Initial Brief at 10.
[258] OPC Initial Brief at 17
[259] *Id*. at 17

OPC pointed out that its proposal mirrors the Commission's treatment of this issue the BGE rate case.[260]

b. Commission Decision

We support Pepco's commitment to pass 100% of all the net merger-related synergy savings to customers as soon as possible. Both Staff witness Ostrander and OPC witness Effron agree that merger synergy costs are front loaded and merger synergy savings are back-ended, and that an adjustment is needed to ensure that current ratepayers are able to realize more of the benefits within the rate effective period. We agree, as stated by Montgomery County, that Mr. Ostrander's proposal will protect ratepayers from the risk of losing the synergies if Pepco does not file a rate case every year the estimated synergies are occurring."[261] We therefore accept Staff's proposal to amortize total merger costs and savings over 5 years which will reduce the revenue requirement by $4,776,000.

11. RMA32: New Billing System Transition Costs

a. Parties' Positions

Pepco witness VonSteuben testified that "on January 5, 2015, PHI replaced the two legacy billing systems with a single, state of the art, customer relationship management and billing system."[262] The new system accommodates the daily business transactions for Pepco's regulated customers in each of its jurisdictions.[263] Mr. VonSteuben testified that the Company added supplemental Customer Service and Billing representatives in order to maintain customer service during the transition to the

[260] *Id*. at 17
[261] Montgomery County Initial Brief at 11.
[262] VonSteuben Rebuttal at 37.
[263] *Id*.

new system.[264] Additionally, Pepco retained some technical resources to support the system deployment.[265] The new billing system is operating and providing the Company with more timely and accurate billing as well as the ability to perform payment processing on a daily basis.[266]

Staff witness Ostrander and OPC witness Effron noted that Pepco testified its 2015 expenses included approximately $7,277,000 million of transition costs related to the new billing system and recorded in Account 903. Both Staff and OPC recommended that because these transition costs are significant and non-recurring they should be removed from test period expenses. However, they recommended two different approaches for how the Company should recover this expense. Staff witness Ostrander recommended that the $7,277,000 million be amortized over a period of five years to include one year of amortization in the test period and the remaining unamortized costs in a regulatory asset subject to future amortization.[267] OPC witness Effron recommended removing the $7,277,000 million transition expense entirely.[268]

b. <u>Commission Decision</u>

The Company identified a $16.7 million expense associated with the new billing system, of which approximately $7.3 million were non-recurring transition costs.[269] As we have done with other large non-recurring expenses such as major storm expenses, we agree with Staff's adjustment to amortize the $7.3 million over 5 years with the unamortized costs placed in a regulatory asset.

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[264] *Id*.
[265] *Id*.
[266] *Id*. at 38.
[267] Ostrander Direct at 48; Ostrander Surrebuttal at 41.
[268] Effron Direct at 18-19; Effron Surrebuttal at13
[269] VonSteuben Rebuttal at 40.

12. RMA 33: Legacy Billing System Transition Costs

a. Parties' Positions

The Company's response in an OPC DR 10-6 indicated that Pepco Maryland's expense associated with the legacy customer information system in 2015 was $1,382,000. Mr. VonSteuben in his rebuttal testimony clarified that this legacy billing expense will decrease to $107,000 in 2016, and an additional $562,000 of the original $1,382,000 will continue to support other Company IT initiatives."[270] Thus, the net reduction to expense is $713,000, which Mr. VonSteuben proposes to establish as a regulatory asset being amortized over five years and the unamortized balance be placed in the Company's rate base.[271]

Staff witness Ostrander proposes that the $713,000 remaining amount of legacy billing be written off because customers should not be required to pay for two billing systems at the same time and the $713,000 is a relatively minor amount.[272] OPC witness Effron agreed with the Staff but offered different rationale. Specifically, Mr. Effron noted that Pepco's response to OPC DR 10-5 identified $8.4 million of legacy Customer Information System ("CIS") expenses are presently being recovered in rates based on a test year consisting of the 12 months ended September 30, 2013 in Case No. 9336. By, 2015, these expenses associated with the legacy billing system had decreased to $1,382,000 and will decrease further to $107,000 as noted above.[273] Mr. Effron points out current rates already include a level of legacy billing system expenses that Pepco is

[270] Effron Surrebutal at 12.
[271] VonSteuben Rebuttal at 43.
[272] Ostrander Surrebuttal at 43.
[273] Effron Surrebuttal at 14.

no longer incurring.[274] He further argues that "the Company is seeking to establish a regulatory asset for transition costs that were not recovered in rates but does not want to credit customers for costs that have been and are being recovered in rates no longer being incurred."[275] For these reasons, OPC finds that there is no justification to create the regulatory asset proposed by the Company and to allow it would result in double recovery for the Company.[276]

b. <u>Commission Decision</u>

We accept the position of Staff and OPC to disallow the Company from establishing a regulatory asset for these continued legacy billing system costs and to allow cost recovery on that asset in the future. Mr. VonSteuben indicated in his testimony that Pepco utilized the legacy billing system in a "read only" mode during the system transition to the new customer billing system and would maintain it for the foreseeable future because it contains key historical information.[277] Since the new billing system now performs all of main transactions to support Pepco customers and the Company is currently collecting in rates for legacy billing system expenses that are no longer being incurred, we agree that allowing the Company to establish a regulatory asset and to recover that asset in the future may result in double recovery.

13. <u>Restated Deferred Storm Costs</u>

a. <u>Parties' Positions</u>

OPC witness Effron testified that the Company's test year rate base included a

[274] *Id*.
[275] *Id*.
[276] *Id*.
[277] VonSteuben Direct at 41.

Regulatory Asset balance of $14,035,000, which consists almost entirely of unamortized deferred storm damage costs incurred between 2010 and 2013.[278] He noted that the deferred storm costs are being amortized over five years with $9.2 million of the amortization reflected in the test year for this proceeding.[279] Mr. Effron pointed out that the amortization of storm damage costs for three past storms will be complete during 2017 (the rate effective period). Specifically, the February 2010 deferred storm coast will be complete in April 2017; the amortization of the January 2011 deferred storm costs will be complete in July 2017 and the amortization of the Hurricane Irene (August 2011) deferred storm costs will be complete in July 2017. Mr. Effron recommended that the Company's amortization expense "will be significantly less than the amortization recorded during the 2015 year" and therefore it should be reduced to the remaining balance as of the date when rates established in this case will go into effect.[280] Mr. Effron warned that, if the actual amortization recorded in the twelve months ended December 31, 2015 is not modified, the Company will over recover the remaining balance of deferred storm damage costs if the rates in this case remain in effect beyond July 2017.[281] Mr. Effron recommended that the balance of these deferred storm costs remaining as of October 31, 2016 be amortized over three years.

In his rebuttal, Mr. VonSteuben argued that OPC's adjustment to restate approved deferred storm amortization costs "undermines every single Commission order" in which the following regulatory assets were granted: February 2010 storm, January 2011 storm

[278] Effron Direct at 14.
[279] *Id*.
[280] Effron Direct at 15.
[281] *Id*.

and Hurricane Irene."[282] The Company contended that the Commission in each of its orders approving the deferred storm damage costs found: 1) that the Company had prudently incurred the expense; and 2) the Company has a right to recover the deferred storm damage costs over a time period that has been deemed reasonable. Mr. VonSteuben pointed out that OPC's adjustment would effectively lengthen recovery of these expenses by three years, which moves away from what the Commission has deemed as a "reasonable" time.

b. <u>Commission Decision</u>

We have, as correctly argued by the Company, fully adjudicated the deferred storm damage costs for each of the three storms being raised by OPC and found that the expenses in each case were prudently incurred and that the Company was entitled to recover the expense over a reasonable period of time which was determined to be five years. However, we accept OPC's adjustment because it will protect ratepayers from over-recovery.

14. <u>NOLC Adjustment</u>

a. <u>Parties' Positions</u>

The Internal Revenue Service ("IRS") rules permit Pepco to accumulate federal tax losses in an accounting balance referred to as a Net Operating Loss ("NOL"). The Company's NOL that can be used in some other tax reporting periods in the future as an offset to taxable income is referred to as the Net Operating Loss Carryforward ("NOLC" or "NOL"). In December 2015, at the end of the test year in this case, Pepco offset federal

[282] VonSteuben Direct at 27-28.

back taxes for the years 2003-2011 with $18,585,000 of its NOLC balance ("the IRS Settlement").

Pepco witness McGowan testified on cross-examination that the IRS Settlement was "hopefully" a once in a generation event, eliminating eight years of Pepco's back taxes.[283] Further, he stated that the reduction in rate base resulting from the IRS Settlement will continue into the rate effective period, will not be reversed, and will be known on "day one" that the new rates go into effect.[284]

Mr. McGowan stated in his rebuttal testimony, however, that the IRS Settlement "caused an immediate reduction in the NOL balance in December 2015." As this "was a one time reduction that will not occur in future years," witness McGowan concluded that "it would be improper to use this reduction to adjust the Company's average test year rate base."[285] Adjustments to average test year rate base should only occur to account for ongoing or forecasted reductions, according to witness McGowan.[286] The Company's initial brief repeated witness McGowan's assertion that "one time" reductions, such as resulted from the IRS Settlement, should not be used to reduce "average" ongoing revenue requirements.[287] OPC witness Effron, however, proposes to reduce Pepco's cumulative NOLC balance by $18.6 million (reducing the average test year to the closing balance) resulting in a corresponding reduction in rate base and a $2 million reduction in the revenue requirement."[288] OPC reasoned that, as it is agreed that the amount of the

[283] Tr. at 94.
[284] *Id.* at 94-95; 98.
[285] McGowan Rebuttal at 38.
[286] *Id.*
[287] Pepco In. Br. at 38.
[288] OPC In. Br. at 14.

IRS Settlement is known, the closing balance in rate base should reflect the entire IRS Settlement.[289]

b. Commission Decision

We agree with People's Counsel that the non-recurring IRS Settlement amount should be fully reflected in Pepco's NOLC account and therefore in the closing balance of Pepco's rate base. The amount of the IRS Settlement is known, and its effects will continue through the rate effective period of the current case. Our treatment of this issue is consistent with our treatment of the payment for Pepco's tax losses made by PHI in 2014. In each case, Pepco was a party to a large transaction that impacted its financial picture. In each instance we find that it is just and reasonable to pass the benefit of those transactions on directly to ratepayers, and therefore we reduce the revenue requirement by $2,000,000.

15. Overtime Adjustment

a. Parties' Positions

Staff witness Ostrander recommended an adjustment to normalize overtime pay expenses due an unexplained overtime pay increase in the Company's revenue requirement. Mr. Ostrander explained that he used the six year period from 2010 to 2015 and applied the same method of averaging overtime costs over a six year period, net of storm costs, that the Commission adopted in Case No. 9286 when Pepco included significant unexplained payroll expenses.[290] Mr. Ostrander also mentioned that he

[289] *Id.*
[290] Ostrander Surrebuttal at 52.

proposed a similar adjustment in Pepco Case No. 9311 to remove significant unexplained overtime payroll increase and the Commission adopted the adjustment.[291]

Pepco witness VonSteuben acknowledges that there had been some changes in the Company that would cause additional overtime expense including increased inspection and maintenance associated with the inspection program in Case No. 9240 as well as RM43 compliance.[292] Mr. VonSteuben agreed that normalization should be use for setting rates when an expense has been volatile over a period of years.[293] With regard to the overtime payroll expenses he stated that he continued to support the test period level of overtime expense proposed by the Company but with the changes in the Pepco's maintenance programs since 2012, a three year normalization of overtime expenses would be more appropriate that a six-year period.[294]

b. <u>Commission Decision</u>

Given that the Company acknowledges that there have been some changes which would contribute to the significant increase in overtime expense and does not strongly oppose Mr. Ostrander's normalization approach, we will accept OPC's adjustment using the 2010 to 2015 six-year normalization approach as previously adopted by this Commission.

16. <u>Outside Legal and Professional Expenses</u>

a. <u>Parties' Positions</u>

Staff witness Ostrander stated that he removed $250,000 of outside legal expenses as a placeholder subject to true-up because Pepco has not provided information that was

[291] Ostrander Surrebuttal at 52.
[292] VonSteuben Rebuttal at 19.
[293] *Id*. at 18.
[294] *Id*. at 19.

requested in Staff DR 17-14 to show that Pepco revenue requirement did not include any merger-related legal expenses.[295] Staff DR 17-14 asked the Company to provide specific information about the amount of outside and in-house legal expense by account used in broad categories. Mr. Ostrander stated that Pepco's response did not provide the requested information. Therefore, Mr. Ostrander argued that the Company has the burden of proof which it did not meet. He also noted that the Commission has in two previous cases adopted reduced outside legal fees that appeared to be excessive. Mr. Ostrander does not argue in this proceeding that the legal fees are excessive but he contends that some of the legal fees could be non-recurring if they are merger-related. Since Pepco did not provide sufficient responses to Staff DR 17-14, Mr. Ostrander proposed a $250,000 reduction in legal expenses.

Staff also proposed removal of $1,000,000 of outside professional expenses as a place holder subject to true-up because again Pepco did not provide sufficient information on a timely basis.[296] Specifically, Mr. Ostrander indicates that he requested information that would allow him to compare outside professional expenses for 2014, 2015 and 2016 to help identify any unusual, excessive or nonrecurring outside professional expenses.[297]

The Company argued that it has provided Staff with a great deal of information on outside professional expenses including a list of all vendors that had test period level expenses of at least $100,000.[298] Mr. Ostrander noted that the Company did in fact identify when responding to Staff DR 39-7 total merger related expenses of $882,206

[295] Ostrander Direct at 65.
[296] *Id.* at 66.
[297] *Id.*
[298] Pepco Initial Brief at 56.

with $222,985 related to Pepco Maryland expenses.[299] The Company indicated that they considered these expenses as underlying support for its proposed reduction of $1,000,000 in outside consulting expenses.

b. Commission Decision

The Company has the burden of proof in recovering outside legal services in base rates. Pepco cited a 2010 Commission decision allowing recovery of some outside legal fees[300], but in that case, the Commission wrote that "recovery of outside legal fees is not assured in the future, unless cost-justified by Pepco in comparison to staffing the work in-house."[301] The Commission has rejected outside legal expenses in recent Pepco cases.[302] We reaffirm today that we do not generally allow recovery of outside legal expenses unless there is good justification, and Pepco did not persuade us that we should do so in this case. Therefore, the Commission will accept Staff's $250,000 reduction for outside legal expenses.

17. RMA 28: Cash Working Capital (CWC)

The Company proposed RMA 28 to adjustment the Company's cash working capital allowance to reflect the use of adjusted cost of service amounts, including proforma interest expense. Cash working capital is generally calculated with a lead lag study. The lead lag study is recognized as an accurate method of determining cash working capital because it is based on a detailed analysis of company specific data. This method estimates the timing difference between 1) when the company renders and receives payment for its services (revenue lag) versus 2) when the Company incurs and

[299] Ostrander Surrebuttal at37.
[300] Pepco Initial Brief at 55-56.
[301] Order No. 83516 at 30.
[302] Case 9311, Order No. 85724 at 64; Case No. 9286, Order No. 85028 at 68.

pays its operating expenses (expense lag). In the present proceeding, we have determined that the recalculated cash working capital reduces the revenue requirement by $558,000.

18. Allowance for Funds Used During Construction (AFUDC)

AFUDC is computed by multiplying the rate of return authorized by the Commission in this case by the average balance of test period Construction Work in Progress ("CWIP") accruing AFUDC. Our adjustment to AFUDC relates to the Commission's allowance for Pepco's RMA 2 in this proceeding. The adjustment reduces the revenue requirement by $3,985,000.

19. Interest Synchronization

Interest synchronization is the procedure that is used to adjust the Company's interest deduction for State and federal income taxes which results from various ratemaking decisions. The interest deduction is calculated by multiplying the rate base by the weighted cost of debt. The resulting interest is then multiplied by the State and federal income tax rates to arrive at the operating income adjustment. Based upon the ratemaking decisions in this Order, the appropriate interest synchronization results in a decrease in the revenue requirement of $769,000.

C. Initiate Another Grid Resiliency Plan

1. Parties' Positions

In addition to the revenue requirement, Pepco is requesting approval for an additional $31.6 million of new incremental investments through the Grid Resiliency Program that is consistent with the current program approved on Case No. 9311 with a slight expansion.[303] The Company wants to continue the program with new incremental investments in feeder improvements and in recloser technology to further improve and

[303] McGowan Direct at 8.

accelerate reliability performance during both normal weather as well as during storm conditions.[304]

The Company initially implemented the Grid Resiliency Program in 2014 and 2015, in which Pepco was authorized to spend $24 million to accelerate the hardening of 24 distribution feeders. The Company reported that the work on these feeders was fully completed and placed in service by the end of 2015.[305] Company witness McGowan testified that as a result of the initial Grid Resiliency Program the Company has experienced SAIFI improvement of 73% and SAIDI improvement of 97% on these feeders including all outage events.[306] In the present case, the Company is proposing to initiate another GRP and perform work on an additional 24 feeders at a capital cost of $24.0 million, and install 1,000 single phase reclosing devices at capital cost of $7.6 million for a total request of $31.6 million. The Company noted that the work for the GRP extension would be performed in 2017 and 2018.[307]

Staff recommended that the Commission not approve the proposed GRP for 2017-2018 and recommends that the GRC surcharge should also be eliminated.[308] Specifically, Staff commented that the GRP does not appear to have been well planned or executed. Staff witness Shelton commented that project managers typically are expected to manage their project costs within plus or minus 10% of the estimated budget. Here, Ms. Shelton noted that since there were large differences between the actual costs and the approved estimated costs, the Company's recovery for 2014 GRP should be limited.[309]

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[304] *Id*.
[305] *Id*.
[306] McGowan Direct at 9.
[307] *Id*.
[308] Shelton Direct at 8.
[309] *Id*.

Specifically, Staff argued that Pepco's recovery for 2014 GRP be reduced by $1,365,353, the amount of expenditures that exceeded 10 % above their estimates.

Montgomery County agrees with Staff witness Shelton's position and determined that while the County advocates for improved reliability and resiliency it does not believe that the GRP extension is the only way to achieve that goal.[310] The HCNCA also agrees with Staff and Montgomery County. HCNCA argued that the GRC was intended to be a temporary, according to the task force that proposed it.[311] "The GRC should not be continued on an indefinite basis; to do so would make a mockery of the representations that were originally offered to justify it."[312]

2. Commission Decision

We initially approved the Grid Resiliency Program and related surcharge as a response to the public outcry over wide spread power outages throughout the state of Maryland caused by the Derecho storm which exposed the vulnerability of the Maryland's electric distribution system. The Governor appointed the Grid Resiliency Task Force (GRTF) specifically to deal with this crisis, and it recommended that such reliability spending surcharges may be appropriate.[313] It was that backdrop that the Commission approved the GRC. Permitting concurrent cost recovery for reliability investments was to encourage our utilities to accelerate upgrades to their infrastructure and address the immediate need to commit resources to improve the electric distribution system's reliability and resiliency. We find it was effective in doing that. Given the improvements in reliability and resiliency testified to by Mr. Gausman and the fact that

[310] Montgomery County Initial Brief at 3-4.
[311] HCNCA Initial Brief at 46.
[312] HCNCA Initial Brief at 46.
[313] Order No. 85724 at 133-164

on cross examination Mr. Gausman testified that none of the projects being proposed are needed to meet reliability standards in COMAR[314], we reject the Company's proposal for another Grid Resiliency Plan . Additionally, we will not disallow the greater than 10% budget overruns that Staff recommended.

D. <u>Cost of Capital</u>

Pepco's cost of capital, or overall rate of return ("ROR"), consists of its return on equity ("ROE") and return on the cost of long-term debt. The ROR is the rate at which the Company has an opportunity to earn a return on its investment in order to attract and retain investors in a competitive market. While the cost of debt can be directly observed, as debt instruments are generally issued subject to fixed, predetermined interest rates, Pepco's return on equity, however, requires more analysis. Pepco is now a subsidiary of Pepco Holdings LLC and does not issue its own stock, so the market-based rate of return on equity is unobservable. Instead, the Company's ROE is calculated using several methodologies, some of which require the use of a group of companies deemed comparable in risk to Pepco—i.e., a proxy. The resulting ROE should comport with requirements of *Bluefield*[315] and *Hope*[316], wherein the Supreme Court ruled that a utility's rate of return on equity must be comparable to returns earned on investments of similar risk, sufficient to ensure confidence in the Company's financial integrity, maintain and support the Company's credit, and attract investment in its securities.

The Commission looks to the analyses of the parties, which vary in methodology and approach. Notably, different analytical approaches can impact ROE in different

[314] Volume III, Tr. p. 648:11-22
[315] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923).

[316] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

ways. While no party opposed Pepco's cost of debt, the parties presented differing estimations regarding an appropriate ROE. A discussion of those analyses and the parties' proposed ROEs and RORs follows.

1. Company Position

Pepco witness Hevert[317] proposed a return on Pepco's common equity ranging from 10.00% to 10.75%, with a final recommendation of 10.60%.[318] Mr. Hevert based his ROE recommendation, in part, on data from 23 proxy companies he selected from those identified as electric utility companies by the investment research firm, Value Line.[319] Furthermore, all of his proxy companies had investment grade senior bond or corporate credit ratings from S&P.[320] The list included both vertically integrated companies and companies that engaged only in electric transmission and distribution.[321]

In calculating Pepco's ROE, Mr. Hevert applied five analytical approaches: two variants of discounted cash flow ("DCF"); two variants of the capital asset pricing model ("CAPM"); and a "bond yield plus risk premium" ("RP") approach. He also considered additional factors, such as capital market conditions and Pepco's flotation costs.[322]

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[317] Mr. Hevert previously testified on behalf of Pepco in the Company's last rate case, Case No. 9336, regarding the Company's cost of capital.

[318] Hevert Direct at 52.

[319] Mr. Hevert excluded from his proxy list: companies that did not consistently pay quarterly cash dividends; companies whose regulated operating electric income over the three most recently reported fiscal years was less than 60% of total regulated operating income; and companies known to be involved in a merger or other significant transaction. He also expressly excluded Exelon Corporation, PHI's new parent company. Hevert Direct at 11-12.

[320] All of Mr. Hevert's proxy companies had been covered by at least two utility industry equity analysts. Hevert Direct at 12-13.

[321] Mr. Hevert commented that there are no "pure play" state jurisdictional electric transmission and distribution ("T&D") companies to be used as a proxy for Pepco in Maryland. Hevert Direct at 12.

[322] Hevert Direct at 15.

Mr. Hevert began his analysis with the constant growth DCF method, which applies the general DCF theory that a stock's current price represents the present value of all its expected future cash flows—namely, its dividends and growth—and assumes several constant elements.[323] He used stock price data from multiple periods, expected dividend yield data, and earnings per share ("EPS") growth estimates from Zacks, First Call, and Value Line.[324] He reported the mean and mean high results from his calculations but excluded mean low results, arguing that they were "well below" a reasonable ROE estimate and thus highly improbable.[325] Mr. Hevert's unadjusted constant growth DCF results produced a mean range of 9.19% to 9.27% and a mean high range of 9.95% to 10.02%.[326]

Mr. Hevert gave less weight to his constant growth DCF results because, in his view, the model's underlying assumptions might not reflect current market conditions.[327] Instead, he included a multi-stage DCF approach that he believed could better account for different growth rates over three distinct stages of growth—near, intermediate, and long-term growth.[328] Mr. Hevert's unadjusted multi-stage DCF analysis resulted in a mean

[323] *Id.* at 16.
[324] *Id.* at 17, 21.
[325] *Id.* at 21.
[326] *Id.* at 19.
[327] *Id.* at 20. Mr. Hevert testified that recently observed low payout ratios were unlikely to remain constant. He also noted that under the constant growth DCF model, relatively low dividend yield should be associated with relatively high growth rates. Accordingly, "[i]f those relationships do not hold, the model's results should be viewed with some caution." *Id.* at 21.
[328] *Id.* at 23. In the multi-stage DCF model, cash flow over the first two stages comprised the expected dividend data. In the third stage, cash flow equaled both the stock's dividends and its "terminal price", which Mr. Hevert defined as the "expected price at which the stock will be sold at the end of the period…." *Id.* at 22. He calculated the terminal price by dividing the expected dividend by the difference between the cost of equity (i.e., discount rate), and a long-term expected growth rate of 5.35%, which was based on the real Gross Domestic Product growth rate of 3.25% for the period from 1929-2014 plus inflation at a rate of 2.04%. *Id.* at 22, 24-25.

low range of 9.72% to 9.94%, a mean range of 10.19% to 10.41%, and a mean high range of 10.72% to 10.94%.[329]

Mr. Hevert also performed two versions of the CAPM, which added a risk premium to a basic risk-free return to compensate investors for any systematic or non-diversifiable risk associated with the security.[330] Mr. Hevert's risk-free return for his CAPM analysis was based on three different long-term Treasury estimates.[331] He developed forward-looking market risk premiums and used beta coefficients to gauge non-diversifiable risk—that is, the relative volatility of company stock returns with respect to the overall market.[332] Mr. Hevert calculated and reported mean market risk premiums ranging from 9.65% to 11.88%.[333]

In addition to the standard CAPM, Mr. Hevert also evaluated Pepco's common equity requirements under the empirical form of the CAPM analysis ("ECAPM"). The ECAPM contained a 75% weighting of the product of the beta coefficient and the calculated market risk premium, plus a 25% weighting of the market risk premium by itself, unaffected by the beta coefficient.[334] The ECAPM purportedly adjusted the CAPM

[329] *Id.* at 26.
[330] *Id.* at 28. The CAPM formula contains four components and is expressed as: $k = r_f + \beta(r_m - r_f)$, where k is the required ROE for a security, β is the Beta coefficient for that security, r_f is the risk-free rate of return, and r_m is the expected return on the market as a whole. Regarding r_f, a stock that tends to respond less to market movements has a Beta less than 1.0, while stocks that tend to be more volatile than the market have Betas greater than 1.0. *Id.* at 28-29.
[331] Mr. Hevert used (1) the current 30-day average yield of 2.96% on 30-year U.S. Treasury bonds, (2) the near-term projected 30-year Treasury yield of 3.45%, and (3) the long-term projected 30-year Treasury yield of 4.65%. *Id.* at 30.
[332] For his market risk premium estimates, Mr. Hevert used a DCF analysis to estimate the market required return by combining expected dividend yields with the projected earnings growth rates, and then subtracted the current 30-year Treasury yield. *Id.* at 30-31.
[333] *Id.* at 32.
[334] *Id.* at 29. The ECAPM formula can be expressed as: $k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f)$. *Id.*

results upward for low beta stocks.[335] His ECAPM model produced a mean ROE range of 10.63% to 12.50%.[336]

Mr. Hevert applied one final risk premium approach to evaluate Pepco's common equity requirements—the bond yield plus risk premium method. Like the CAPM approach, the cost of equity under this method comprised a base rate (i.e., bond yield) plus an additional amount to account for risk.[337] Mr. Hevert used a base rate consisting of the current long-term 30-year Treasury yield and added an "equity risk premium" which he calculated based on historical, authorized returns for electric utilities from January 1, 1980 to January 15, 2016.[338] Mr. Hevert calculated an ROE range between 10.04% and 10.47%.[339]

Following his ROE analysis, Mr. Hevert then made several adjustments to his ROE range to further account for Pepco's specific business risks. First, he added twelve basis points to Pepco's ROE to account for flotation costs—namely, those costs associated with PHI's two most recent issuances of common stock.[340] Mr. Hevert explained that the flotation costs factored into the Company's capital costs and were incurred over time and mostly prior to the test year.[341] Mr. Hevert reasoned that common equity remained on the Company's balance sheet indefinitely and, therefore, the return on the equity would be subject to dilution in perpetuity.[342]

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[335] *Id.* at 29-30.
[336] *Id.* at 32.
[337] *Id.* at 32-33.
[338] Mr. Hevert defined the Equity Risk Premium as the difference between the historical Cost of Equity, or ROE, and the then-prevailing long-term Treasury yields. *Id.* at 33.
[339] *Id.* at 35.
[340] A basis point is 0.01 percent.
[341] Hevert Direct at 36. Mr. Hevert noted that PHI incurred $22,736,874 in cumulative issuance costs for its two most recent issuances. Hevert Direct, Schedule RBH-7.
[342] *Id.* at 37.

Mr. Hevert also made adjustments for a changing capital market environment and, more specifically, the possibility of rising interest rates after the Federal Reserve completed its Quantitative Easing initiative in 2014 and subsequently raised the Federal Funds rate in December 2015. He explained that in view of the Federal Reserve's ongoing rate normalization process, investors could perceive greater opportunity for economic growth, which could lead to increases in growth rates, interest rates and dividend yields. This, in turn, would produce higher ROE estimates under a DCF model. He also discussed potential increases in equity market volatility following the Federal Reserve's conclusion of its quantitative easing policy, testifying that near-term market volatility recently increased in 2015, and equity risk is currently higher than historical average levels.[343] Mr. Hevert concluded that these factors, among others, reflected changing market conditions.[344]

With regard to the Company's capital structure, Mr. Hevert calculated the average capital structure for each of his proxy companies over the last eight quarters. The overall mean common equity ratio for the proxy companies was 52.78% (with a range of 46.50% to 66.01%) and the mean long-term debt ratio was 47.22%.[345] He therefore concluded that Pepco's proposed capital structure of 49.55% common equity and 50.45% debt was appropriate and consistent with the capital structures of the proxy companies.[346]

In his Rebuttal Testimony, Mr. Hevert updated his calculations for his DCF, CAPM, and RP cost of equity analyses with data through June 30, 2016. He applied those analyses to a revised version of his proxy group as well as a "combined proxy

[343] *Id.* at 43-44.
[344] *Id.* at 50.
[345] *Id.* at 51.
[346] *Id.* at 52.

group" that consisted of the proxy companies proffered by the opposing parties' witnesses.[347] He also refuted the analyses and recommendations of the other parties' witnesses.

Lastly, Pepco witness Kevin M. McGowan stated that Pepco is requesting an overall rate of return of 8.01%, based on Pepco's capital structure and Mr. Hevert's cost of capital analysis.[348] Mr. McGowan stressed that the Company's capital structure was calculated in the same manner accepted by the Commission in the Company's previous rate cases. He stated that Pepco's 49.10% common equity ratio was within the Company's target 50% and was further consistent with industry practices and averages.[349]

2. <u>Other Parties' Positions</u>

a. AOBA

AOBA witness Bruce Oliver adopted Pepco's proposed capital structure but noted that it was neither reflective of Pepco's average capital structure during the test year nor indicative of what Pepco would employ during the rate effective period.[350]

Mr. Oliver criticized Mr. Hevert's recommended ROE as being overstated and driven by analyses and scenarios that failed to reflect costs for risk investments comparable to Pepco's distribution utility operations.[351] He criticized Mr. Hevert's CAPM and ECAPM analyses as being inappropriately high and challenged Mr. Hevert's bond yield plus risk premium analysis.[352]

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[347] *Id.* at 101.
[348] McGowan Direct at 10.
[349] *Id.* at 10-11. Mr. McGowan explained that to maintain a minimum equity ratio within the range of 49% to 50%, PHI makes equity contributions into Pepco while Pepco makes dividend payments to PHI.
[350] B. Oliver Direct at 10-11.
[351] *Id.* at 13. Mr. Oliver observed that Mr. Hevert's ROE recommendations before various regulatory commissions over the last three years have been, on average, 77 basis points higher than the actual ROEs approved by those commissions. *Id.* at 15.
[352] *Id.* at 16-17.

With regard to Mr. Hevert's DCF analysis, Mr. Oliver chided Mr. Hevert for introducing the multi-stage DCF approach, which he had not previously employed in Pepco's prior rate cases. Mr. Oliver argued that this additional approach offered little, if any, additional insight into the costs of comparable risk investments.[353] He likewise criticized Mr. Hevert for asymmetrically removing his "mean low" and "median low" ROE estimates from his results, which biased his ROR recommendation upward.[354]

Mr. Oliver performed his own DCF and CAPM analyses on Mr. Hevert's proxy group and averaged the two results.[355] This average served as the lower bound of his ROE range. For the upper bound, Mr. Oliver took Mr. Hevert's ROE recommendation, eliminated the 12-point flotation cost adjustment, and further adjusted the ROE downward to reflect the average adjustment made by sister regulators in recent proceedings, an adjustment he referred to as a "Regulators' Adjustment Factor".[356] Mr. Oliver established an ROE range from 8.76% to 9.71%.[357] Based on this range, Mr. Oliver recommended an ROE of 9.25%, which corresponded closely with the average of witness Hevert's mean constant growth DCF results.[358]

Mr. Oliver urged the Commission to reject Pepco's request for flotation costs and testified to several shortcomings in Mr. Hevert's argument for the adjustment. He pointed out that post-merger Pepco will no longer issue publicly traded common stock. He further argued that a 12 basis point upward adjustment would result in over-recovery

[353] *Id.* at 14.
[354] *Id.* at 21.
[355] *Id.* at 25-26.
[356] *Id.* at 26.
[357] *Id.* at 25-26.
[358] *Id.* at 26.

insofar as it would significantly exceed any flotation costs experienced by Mr. Hevert's proxy companies in recent periods.[359]

Mr. Hevert analyzed Bruce Oliver's recommended ROE estimates for Pepco and challenged Mr. Oliver's "Regulators' Adjustment Factor", his DCF analysis, and the CAPM and market risk premium estimates.[360] Mr. Hevert responded to Mr. Oliver's criticisms regarding his methodologies, defending his DCF results and inclusion of the multi-stage DCF model.[361] Mr. Hevert also disagreed that there was no need for a flotation cost adjustment, arguing that excluding the costs would lead to drops in growth rate and ROE. He further maintained that Exelon's acquisition of Pepco did not negate the need to recover these costs.[362]

Mr. Oliver submitted Surrebuttal Testimony addressing, among other things, Mr. Hevert's objection with regard to the "Regulators' Adjustment Factor". Mr. Oliver also defended his CAPM analysis and repeated his objection to Pepco's request for a flotation cost adjustment, arguing that the request was unsupported under PHI's cost allocation manual.[363]

b. HCNCA

HCNCA witness Baudino recommended that the Commission approve a ROE of 9.00%.[364] He offered no comment on Pepco's proposed capital structure.

With regard to the market environment, Mr. Baudino pointed out that interest rates have generally declined since 2008, and the U.S. economy is currently in a low

[359] *Id.* at 24.
[360] Hevert Rebuttal at 23.
[361] *Id.* at 26.
[362] *Id.* at 32.
[363] B. Oliver Surrebuttal at 7-8.
[364] Baudino Direct at 3.

interest rate environment that favors lower risk regulated utilities.[365] He cautioned the Commission against raising ROE in anticipation of higher interest rates that may or may not occur.[366] Additionally, Mr. Baudino observed that, as a matter of financial health and overall risk, the Company was low cost and low risk with strong A/A senior secured bond ratings. He further reasoned that the completion of the Pepco-Exelon merger "has removed substantial uncertainty from Pepco's credit outlook."[367]

Mr. Baudino performed both constant growth DCF and the CAPM analyses in estimating his ROE recommendation. His proxy group comprised 12 electric companies with "A" or better bond ratings that further had at least 50% of their revenues from electric operations.[368] For his DCF analysis, Mr. Baudino calculated an average dividend yield for his proxy group and in addition to expected growth rates, which he calculated using two different methods.[369] Mr. Baudino's mean DCF results ranged from 8.64% to 8.87%.[370] For his CAPM analysis, Mr. Baudino developed both forward-looking and historical-based CAPM ROEs. He used median growth rate estimates, an adjusted historical market risk premium,[371] and a risk free rate..[372] Mr. Baudino's forward-looking CAPM results ranged from 8.03% to 8.28%, while his historical CAPM results ranged from 6.02% to 7.49%.[373]

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[365] *Id.* at 5, 8, 10.
[366] *Id.* at 10.
[367] *Id.* at 13.
[368] Mr. Baudino excluded companies that no longer paid dividends as well as companies that were either recently or currently involved in significant merger transactions. Baudino Direct at 19-20.
[369] *Id.* at 21-24.
[370] *Id.* at 25.
[371] *Id.* at 29-30. Mr. Baudino adjusted his historical market risk premium to account for substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001. Mr. Baudino did not believe that P/E would continue to increase in the future. *Id.* at 30.
[372] *Id.* at 30.
[373] *Id.* at 31.

Mr. Baudino's recommended ROE of 9.0% placed Pepco at the top of his DCF ROE range, rounded upward. He did not rely on his CAPM model but, instead, used it to further support the reasonableness of his ROE recommendation.[374]

Mr. Baudino raised several challenges to Pepco witness Hevert's ROE analyses, which in his view inflated Pepco's investor-required return.[375] He criticized Mr. Hevert for including in his proxy group three companies that are currently involved in significant merger activities.[376] He also criticized Mr. Hevert for ignoring his own constant growth DCF results, which served to overstate his recommended ROE.[377] With regard to Mr. Hevert's multi-stage DCF model, Mr. Baudino found no support for Mr. Hevert's underlying assumptions and concluded that investors were not likely to use the model.[378] Mr. Baudino also critiqued Mr. Hevert's CAPM analysis[379] and disagreed with the applicability of Mr. Hevert's ECAPM model, arguing that investors were unlikely to use this formulation to "correct" CAPM returns for electric utilities.[380]

With regard to Mr. Hevert's bond yield risk premium analysis, Mr. Baudino questioned the wisdom in relying on such an approach, referring to it as a "blunt instrument" for estimating ROE and suitable only for providing "general guidance on the current authorized ROE for a regulated electric utility."[381] Lastly, as with the other parties save Pepco, Mr. Baudino recommended against an adjustment for flotation costs, reasoning that current stock prices likely already account for such costs.[382]

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[374] *Id.* at 32.
[375] *See* Baudino Direct at 3.
[376] Baudino Direct at 35.
[377] *Id.* at 35-36.
[378] *Id.* at 38.
[379] *Id.* at 40-42.
[380] *Id.* at 42.
[381] *Id.* at 43.
[382] *Id.* at 37.

In his Rebuttal Testimony, Mr. Hevert responded to Mr. Baudino's proxy group critique and defended his DCF analyses and particularly his preference for the multi-stage DCF model over constant growth DCF in this matter.[383] Mr. Hevert analyzed Mr. Baudino's ROE analyses and disagreed with several aspects of his CAPM analysis, including his use of historical market risk premiums insofar as CAPM was a forward-looking analysis.[384] Mr. Hevert also refuted Mr. Baudino's characterization of his bond yield plus risk premium model and argued that the model provided a sound method for quantifying the relationship between the cost of equity and changing interest rates.[385] He also responded to Mr. Baudino's critique against a flotation cost adjustment, claiming that the net proceeds received by Pepco were below market price of the offerings as a result of the direct issuance costs.[386]

Mr. Baudino submitted Surrebuttal Testimony updating his ROE analysis with updated market data.[387] The updated analysis still supported his initial ROE recommendation of 9.0%.[388]

c. OPC

OPC witness Dr. Woolridge adopted Pepco's proposed capital structure and long-term debt cost rate.[389] His main contention was in the calculation of Pepco's ROE. Dr. Woolridge applied the constant growth DCF and CAPM methods to develop a recommended ROE for Pepco of 8.65%, which was at the upper end of his equity cost

[383] Hevert Rebuttal at 85, 87.
[384] *Id.* at 96.
[385] Hevert Rebuttal at 98.
[386] *Id.* at 100.
[387] Baudino Surrebuttal at 2.
[388] *Id.* at 3.
[389] Woolridge Direct at 4.

rate range of 7.9% to 8.65%.[390] When Pepco's capital structure and senior capital cost rates are taken into consideration, Dr. Woolridge calculated an overall rate of return (ROR) of 7.05% for Pepco's electric distribution utility operations.[391]

Dr. Woolridge selected 31 electric utilities as his proxy group (the "Electric Proxy Group"), using different criteria than Pepco witness Hevert used to select his 23 comparables (the "Hevert Proxy Group").[392] He performed his analyses using both the Electric Proxy Group and the Hevert Proxy Group.[393]

Dr. Woolridge relied primarily on his DCF analysis for his ROE determination, finding that the DCF method provided the best measure of equity cost rates for utilities. He also performed the CAPM analysis but put less weight on its results because the CAPM provided a "less reliable indication of equity cost rates for public utilities."[394] In performing his DCF calculation, Dr. Woolridge did not rely exclusively on the earnings per share forecasts, opining instead that the appropriate growth rate in the DCF model was the dividend growth rate.[395] He argued that long-term EPS growth rate forecasts of Wall Street securities analysts were known to be overly optimistic and upwardly biased.[396] Therefore, according to Dr. Woolridge, the DCF growth rate should be adjusted downward to correct for any upward bias.[397] As applied to both Dr. Woolridge's Electric Proxy Group and the Hevert Proxy Group, the DCF analyses produced the same equity cost rate of 8.65%.[398]

[390] *Id.* at 4-5.]
[391] *Id.* at 5.
[392] *Id.* 30-31.
[393] *Id.* at 10.
[394] *Id.* at 43.
[395] *Id.* at 53.
[396] *Id.* at 53-54.
[397] *Id.* at 54.
[398] *Id.* at 59.

Dr. Woolridge also performed a CAPM study. Using standard CAPM components, Dr. Woolridge determined an equity cost rate of 7.9% for the Electric Proxy Group and 8.1% for the Hevert Proxy Group.[399] Given the results of his DCF and CAPM analyses, Dr. Woolridge calculated an ROE range of 7.90% to 8.65% for both proxy groups. Because he relied primarily on the DCF model, however, he chose a final ROE recommendation at the upper end of the range and concluded that the appropriate ROE was 8.65%[400]

Additionally, Dr. Woolridge testified regarding capital market conditions, arguing that capital costs have declined since the Commission last addressed Pepco's ROE in 2014. Since 2014, although economists predicted an increase in long-term interest rates in response to the ending, they were wrong and interest rates declined.[401] He noted that the 30-year Treasury yield, which was 4.0% in 2013, declined to 2.5% over the next year. Currently, the 30-year Treasury yield is 2.5%.[402] According to Dr. Woolridge, long-term trends reflect more slowed growth in annual economic production and income. He expected to see the cost of capital decline, thereby keeping interest rates low.[403]

Beyond interest rates, Dr. Woolridge also testified that authorized ROEs for electric utilities have generally decreased since Pepco's last rate case. He cited data from Regulatory Research Associates indicating that "authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, to 9.8% in 2013, to 9.76% in 2014, to 9.58% in 2015, and to 9.86% in the first quarter of 2016."[404]

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[399] *Id.* at 69.
[400] *Id.* at 70.
[401] *Id.* at 6.
[402] *Id.* at 7.
[403] *Id.* at 26.
[404] *Id.* at 8.

After presenting his own ROE analysis, Dr. Woolridge critiqued Mr. Hevert's ROE analysis, criticizing him for basing his analyses and recommendations on "the speculative and oft-disproven assumption of higher interest rates and capital costs."[405] Dr. Woolridge argued that this upward bias also carried into the substance of Mr. Hevert's DCF, CAPM, and risk premium analyses. Dr. Woolridge also found no basis for a flotation cost adjustment.[406]

Dr. Woolridge criticized Mr. Hevert's DCF equity cost estimates for, among other things, giving little, if any, weight to his constant growth DCF results and employing in his multi-stage DCF analysis a terminal growth rate that was not reflective of prospective U.S. economic growth.[407] He objected to Mr. Hevert's reliance on the ECAPM approach, which he pointed out has not been theoretically or empirically validated, and he faulted Mr. Hevert's CAPM analysis for using market risk premiums that were based on "the upwardly-biased long-term EPS growth rate estimates of Wall Street analysts."[408] Lastly, Dr. Woolridge dismissed Mr. Hevert's bond yield plus risk premium analysis as inflating the equity cost rate. He disagreed with Mr. Hevert's use of an excessive risk premium derived from historic authorized ROEs and Treasury yields, which, according to Dr. Woolridge, did not reflect investor behavior but, rather, Commission behavior.[409]

In reviewing Dr. Woolridge's ROE analysis, Mr. Hevert challenged the reasonableness of OPC's recommendation, pointing out that Dr. Woolridge's recommended ROE was 90-135 basis points lower than the recent average returns for electric utilities and 110 basis points lower than the ROEs most recently authorized by

[405] *Id.* at 76.
[406] *Id.* at 97-98.
[407] *Id.* at 78.
[408] *Id.* at 87-88.
[409] *Id.* at 96.

the Commission in June 2016 for BGE's electric and natural gas operation.[410] Mr. Hevert also disagreed with Dr. Woolridge's proxy group selection and argued that the companies were not sufficiently comparable to Pepco.[411]

Mr. Hevert criticized Dr. Woolridge's DCF analyses and results as incompatible with current market conditions and inconsistent with the underlying assumptions of the DCF model.[412] He also noted that he was unable to replicate Dr. Woolridge's analyses.[413] Mr. Hevert disagreed with Dr. Woolridge's contention that dividend and book value growth rates were the appropriate measures of expected growth, insisting instead that earnings growth was "the fundamental driver of the ability of pay dividends."[414] In response to Dr. Woolridge's critique of Pepco's DCF analysis, Mr. Hevert defended his multi-stage approach.[415]

Mr. Hevert also objected to Dr. Woolridge's CAPM analysis, arguing that the resultant cost of equity of 7.90% was unreasonable and "unduly low".[416] Notwithstanding the fact that Dr. Woolridge did not rely on his CAPM analysis in formulating his ROE recommendation, Mr. Hevert questioned the validity and relevance of Dr. Woolridge's equity risk premium estimates, arguing that "such important elements of his CAPM analysis contradict each other…."[417] Mr. Hevert then addressed in detail Dr. Woolridge's criticism of his own (Hevert's) CAPM and bond yield plus risk premium analyses. Mr. Hevert disagreed with Dr. Woolridge's position on Pepco's request for

[410] Hevert Rebuttal at 33.
[411] Hevert Rebuttal at 35.
[412] *Id.* at 37.
[413] *Id.* at 54.
[414] *Id.* at 50.
[415] *Id.* at 55-60.
[416] *Id.* at 63.
[417] *Id.* at 67.

flotation costs.[418] He rejected Dr. Woolridge's argument that flotation costs for electric utility companies should result in a reduction to the equity cost rate, countering that flotation costs are "true and necessary costs to the issuer" and that denial of their recovery would deny the Company a portion of its expected return.[419]

Dr. Woolridge provided Surrebuttal Testimony responding to Mr. Hevert's Rebuttal Testimony on the topics of changes since Pepco's last rate case, the subjectivity and reasonableness of Dr. Woolridge's ROE recommendation, various DCF analysis issues raised by Mr. Hevert, capital market conditions, and the trend in state authorized ROEs.[420] Dr. Woolridge defended his application of the DCF model and further addressed Mr. Hevert's arguments concerning the multi-stage DCF model.[421]

Dr. Woolridge rejected Mr. Hevert's suggestion that "nothing has changed" since the last rate case.[422] In that regard, Dr. Woolridge reiterated his position that capital costs and interest rates have declined in recent years and are at historic low levels. Furthermore, they would likely remain low with "sluggish economic growth and low inflation."[423] He pointed out that the average authorized ROE for electric utility delivery or distribution companies specifically also declined from 9.85% in 2011 to just over 9.2% in 2015.[424] In view of an average ROE of just over 9.0%, Dr. Woolridge argued that "an earned ROE of about 9.0% is more than adequate to meet investors' return requirements."[425]

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418 *Id.* at 82.
419 *Id.* at 82-83.
420 Woolridge Surrebuttal at 1-2.
421 *Id.* at 1-2, 8.
422 Woolridge Surrebuttal at 2; *see also* Hevert Rebuttal at 3.
423 Woolridge Surrebuttal at 18.
424 *Id.* at 23.
425 *Id.* at 26.

d. Staff

Staff witness VanderHeyden recommended that Pepco's cost of equity should be 9.57% and its overall rate of return should be 7.51%.[426] He accepted Pepco's proposed capital structure.[427]

Regarding proxy groups, he testified that a utility's return should be comparable to other companies of similar risk. Mr. VanderHeyden observed that Pepco, as an electricity provider, was solely a distribution company, devoid of any generation or transmission assets in its rate base. Given the few stand-alone electric distribution companies from which to form a representative proxy group, Mr. VanderHeyden included companies from Value Line's Electric East, Central, and West groups, noting that many of them had other operations, such as generation and non-regulated businesses.[428] In total, Mr. VanderHeyden's proxy group consisted of 32 companies.[429] Mr. VanderHeyden employed both DCF and CAPM methodologies to calculate an average ROE for Pepco.[430] For his DCF analysis, Mr. VanderHeyden used closing stock prices and dividend data from Yahoo Finance and annual earnings growth data from Value Line for the period ending in 2020 to 2021.[431] He excluded the dividend growth results from his DCF calculation because in his opinion, many utilities would be unable

[426] VanderHeyden Direct at 2.
[427] *Id.* at 9.
[428] *Id.* at 8.
[429] Mr. VanderHeyden removed PPL Corporation from his proxy group because of its recent spinoff transaction. VanderHeyden Direct at 8-9. He also excluded companies with a market capitalization under $1Billion as well as Exelon Corporation. *Id.* at 9.
[430] VanderHeyden Direct at 10.
[431] *Id.* at 11. Mr. VanderHeyden explained that he chose to use earnings growth information over dividend growth data in his DCF calculation for growth over time because as utilities undertake heavy spending on reliability, many of them would be "unable or unwilling to boost dividends significantly…." *Id.* at 12. Instead, the "earnings reinvested in plant would be expected to drive higher earnings in the future…." *Id.*

or unwilling to increase dividends while spending heavily on reliability improvements.[432] Mr. VanderHeyden's DCF analysis resulted in an individual ROE of 9.36%, which reflected the proxy group average.[433] For his CAPM analysis, Mr. VanderHeyden calculated an ROE of 9.78% for Pepco.[434]

Mr. VanderHeyden did not include an adjustment for flotation cost in his ROE estimate in this matter. He testified that the Commission clearly instructed in previous orders that an award for flotation costs would be granted only based on verifiable costs of issuing new stock.[435] He pointed out that Pepco has not issued any additional stock since its last rate case No. 9336. In that regard, Pepco's cost of capital testimony reflected only the Company's cost of issuing stock in 2008 and 2012. Mr. VanderHeyden also reasoned that insofar as Pepco was purchased by Exelon, PHI's flotation costs would have been absorbed in Exelon's purchase price if PHI was purchased at a value greater than its book value.[436]

Mr. VanderHeyden critiqued Mr. Hevert's cost of capital analysis. Regarding Mr. Hevert's DCF analysis, he noted that Mr. Hevert performed two variants of the DCF model and chose the multi-stage DCF results over the constant growth DCF results. Mr. VanderHeyden testified that his own DCF results fell within Mr. Hevert's results under constant growth DCF but not under his multi-stage analysis.[437]

Mr. VanderHeyden stated that unlike Pepco he did not use the ECAPM method because he did not find it necessary to use an adjustment for beta in this case that would

[432] VanderHeyden Direct at 12.
[433] *Id.* at 10, 13.
[434] *Id.* at 14.
[435] *Id.* at 17.
[436] *Id.* at 18.
[437] *Id.* at 19.

have compensated investors with higher returns for non-utility risk.[438] Mr. VanderHeyden further noted that ECAPM was not a mainstream method. Additionally, he questioned Mr. Hevert's use of a size adjustment in his ECAPM method and its validity under current market conditions.[439]

He also criticized Mr. Hevert's application of the bond yield plus risk premium method, characterizing it as an incomplete indicator of investor's required return because the historical authorized returns granted by state commissions may be higher or lower than the returns on market equity that current investors expect.[440] According to Mr. VanderHeyden, Pepco failed to demonstrate a reliable connection between the previously authorized returns and a current investor's expectations.

Dr. Woolridge in his Rebuttal Testimony raised several purported errors by Mr. VanderHeyden, including: (1) inconsistencies in the composition of his proxy group; (2) asymmetrical elimination of low-end observations in his DCF results; (3) a flawed measure of equity risk premium for his CAPM analysis.[441] Dr. Woolridge also pointed out that Mr. VanderHeyden apparently changed his ROE methodologies in this proceeding and chose not to use two approaches previously employed by him in prior rate cases—namely, the Internal Rate of Return ("IRR") and Risk Premium Build Up ("RP") methods.[442]

Contemporaneous with Dr. Woolridge's Rebuttal, Mr. Hevert presented numerous criticisms of Mr. VanderHeyden's ROE testimony in his Rebuttal Testimony. He too objected to Mr. VanderHeyden's proxy group selection and challenged his DCF and

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[438] *Id.* at 20.
[439] *Id.* at 21.
[440] *Id.* at 22.
[441] Woolridge Rebuttal at 2.
[442] *Id.* at 2-3.

CAPM calculations. Mr. Hevert noted that while Staff's constant growth DCF analysis was generally consistent with his own analysis, his (Hevert's) constant growth DCF analysis was 26 basis points higher than Mr. VanderHeyden's estimate.[443] Furthermore, Mr. Hevert faulted Mr. VanderHeyden for not including in his ROE analysis an ECAPM model as previous Staff witnesses have done in past rate cases.[444] Mr. Hevert also continued to defend his own use of the utility risk premium model, arguing that under the *Hope* and *Bluefield* standards, utility commissions set the authorized ROE equal to investors' expected return.[445]

Lastly, with regard to flotation costs, Mr. Hevert disagreed with Staff's reasoning that Pepco's recent acquisition by Exelon negated the need to adjust for flotation costs.[446] He argued that the dilution of equity remained unaffected by any acquisition premium paid by Exelon.[447]

In his Surrebuttal Testimony, Mr. VanderHeyden responded to Dr. Woolridge's concerns and defended: (1) the composition of his proxy group composition; (2) his choice not to use the IRR and Risk Premium Buildup methods to develop ROE in this case; (3) his elimination of several low-end DCF ROEs that he believed were inappropriate for his analysis; and (4) his use of historical market risk premium in his CAPM analysis.[448]

Mr. VanderHeyden also provided surrebuttal response to Mr. Hevert's critiques regarding: (1) certain companies included in the proxy group; (2) election of the CAPM

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[443] Hevert Rebuttal at 13-14.
[444] *Id.* at 16-17.
[445] *Id*. at 20.
[446] *Id*.at 21.
[447] *Id*.at 22.
[448] VanderHeyden Surrebuttal at 3-10.

method over the ECAPM approach; (3) the need for flotation expense as a requirement for a flotation ROE adjustment; and (4) the validity of authorized ROE as a risk premium method.[449]

Mr. VanderHeyden testified that Staff's and Pepco's DCF results were "more or less the same" and that the difference in final recommended ROE was due to Mr. Hevert's use of multi-stage DCF, ECAPM with CAPM and his use of a risk premium method based on awarded returns.[450] Accordingly, the parties' similarities become apparent once the Commission removes the flotation adder, the ECAPM, and the comparable earnings methods and then averages Pepco's constant growth DCF with Staff's CAPM.[451]

Mr. VanderHeyden summarized the parties' ROE recommendations in the following table:[452]

Table 1 – Summary of ROE Calculations					
Method and Adjustments	**PEPCO**	**Staff**	**AOBA**	**HCNCA**	**OPC**
DCF	8.84%-9.60%	9.36%	8.82%	8.64-8.87%	8.65%
DCF Mult.-Stg.	9.20%-10.55%	n/a	n/a	n/a	n/a
CAPM	8.92%-13.01%	9.78%	8.70%	6.02%-8.28%	7.90%-8.10%
ECAPM	9.24%-13.45%	n/a	n/a	n/a	n/a
Utility RP	10.04%-10.39%	n/a	n/a	n/a	n/a
RAF	n/a	n/a	9.71%	n/a	n/a
Flotation Adj.	12 bp	n/a	n/a	n/a	n/a
ROE Recommendation	**10.60%**	**9.57**	**9.25%**	**9.00%**	**8.65%**

[449] *Id*. at 11-21.
[450] *Id*. at 11.
[451] *Id*.
[452] *Id*. at 3.

3. <u>Commission Decision</u>

We begin by observing that none of the parties object to Pepco's current capital structure ratio of 49.55% common equity to 50.45% long-term debt. We therefore accept it for our analysis along with the uncontested cost of long-term debt of 5.48%.

The parties' final ROE recommendations in this case range from 8.65% to 10.6%, with Pepco proffering the highest ROE and OPC the lowest. In terms of total revenue requirement, the parties' spread reflects a total difference of approximately $49.7 million. In reviewing the parties' proposed ROEs, we note that they are supported by extensive analysis applying, in some cases, multiple methodologies. Nevertheless, the witnesses have also relied on subjective judgment as to the quantitative inputs, the analysis methodologies performed—whether DCF, CAPM, risk premium, or any combination (or variant) thereof, and in some cases a decision to exclude specific results. The fact that the parties applied more than one methodology is not itself a fault. We have stated in prior rate cases that we are not willing to rule that there can be only one correct method for calculating an ROE. Indeed, the complexity of this subject cannot be captured by a single mathematical formula.

In its three most recent rate cases,[453] the Company consistently requested an ROE of 10.25% or greater. Each time we declined to adopt the Company's recommendation in view of the economic and risk factors faced by the Company at the time. This time is no different. We have considered Pepco's status as a monopolistic provider of electric distribution service in an economically stable service territory, its heavily residential

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[453] *See In the Matter of the Application of Potomac Electric Power Company for Authority to Increase its Rates and Charges for Electric Distribution Service*, Case No. 9286; *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*, Case No. 9311; *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Case No. 9336.

customer base, the completion of the recent merger between PHI, Pepco's parent holding company, and Exelon Corporation, and the fact that the Company does not own generation. We are also mindful of investor perception of utilities constituting low-risk investments. Thus, we are once again presented with the question of what has changed since we last established a just and reasonable ROE for Pepco that would now justify a higher return?

Our current reality is that interest rates have generally declined since 2008 and have since remained persistently low. Indeed, interest rates have remained at historic lows for nearly a decade and even fallen since the last rate case.[454] Not surprisingly, long-term Treasury yields have also declined. As OPC witness Dr. Woolridge pointed out, the downward trend in long-term rates, despite the Federal Reserve's decision to terminate its bond buying program and increase the Federal Fund rate range, reflects more slowed growth in annual economic production and income.[455] Accordingly, insofar as investors rely on current market data, the data do not support Pepco's proposed increase but, rather, favor a lower cost of capital than Pepco's current authorized ROE of 9.62%.

Additionally, we consider Pepco's current state of financial health and note in particular its strong secured bond rating, which indicates low risk. In this regard—i.e., the risk facing the Company's electric distribution operations in Maryland—we conclude that Pepco's situation has not changed in a manner that would justify an increase in ROE. First, Pepco continues to operate in a low-interest rate environment. Second, before the Exelon-PHI merger, Moody's characterized PHI, Pepco's parent holding company, as

[454] *See, e.g.*, HCNCA Ex. 30 at RAB-2.
[455] Hevert Direct at 22-25.

having a “low business risk profile.”[456] The merger itself was characterized as “credit positive”.[457] Post-merger, we find that Pepco continues to constitute a low-risk investment. Third, the Company is a monopoly provider of electric distribution service in a stable service territory in Maryland, which allows several utility-friendly policies (e.g. customer charges, decoupling, etc.) and does not own generating facilities. From a risk standpoint, Pepco has not had any difficulty securing debt financing. Even Mr. Hevert acknowledged that the merger could provide benefits towards the Company’s ability to attract future capital, which would further reduce the Company’s risk level.[458] These developments, among others, all point to a lower ROE for Pepco.[459]

We are not persuaded by Pepco’s argument that an ROE lower than the respective returns we recently authorized for BGE’s electric and gas utility operations[460] would conflict with our prior conclusion regarding electric and gas utility risk.[461] We note that Order No. 85374, which serves as the basis for Pepco’s argument, was issued over three years ago, and our statement there was comparative in nature, made for the purpose of according separate treatment to BGE’s electric and gas operations, as opposed to combining both operations to reach an appropriate return. We did not attempt in that case to establish a floor for all future ratemaking. Indeed, our decision in this case is based on consideration of the record before us and the facts particular to this case. To that end, we examine and decide each utility’s rate application on its own merits to ensure not only that the utility is operating in the interests of the public, but also that its rates are “just and

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[456] HCNCA Ex. 30 at 12.
[457] HCNCA Ex. 30 at 13.
[458] *See* Hr. Tr. at 310.
[459] Mr. Hevert’s recommended ROE of 10.6% is not sustained by Exelon’s own projected return of the impact of the PHI acquisition on earnings per share. Hr’g Tr. at 39.
[460] *See* In re BGE Rate Application, Case No. 9406.
[461] *See* Pepco Br. at 61 (quoting an excerpt from Order No. 85374).

reasonable." Again, we agree that, in general, we treat our utilities the same unless there are facts and circumstances that support different treatment, which we do here.

Our decision today most closely aligns with Staff's recommendation of 9.57%, although we do not expressly reach the same conclusion as Staff. We find that a slightly lower ROE of 9.55% is both adequate and appropriate for Pepco, considering the risks associated with its electric distribution service in Maryland, the current capital market environment, and the fact that Pepco has not issued any new stock since its last rate case. Looking forward, Pepco has not demonstrated that it will issue new stock or incur any flotation costs in the rate effective year.[462] Insofar as PHI previously issued stock and distributed proceeds to Pepco and other subsidiaries, PHI has since merged with Exelon Corporation. Following completion of the merger, Pepco does not take the position that it will begin issuing stock or that Exelon will issue stock on its behalf. We conclude, therefore, that Pepco has not established any direct connection to any verifiable costs associated with any new equity to be issued by Exelon in the rate effective year. Accordingly, we deny Pepco's request for a flotation cost adjustment. For the same reasons, we also find that the previous flotation adjustment of 7 basis points awarded in Pepco's last rate case is no longer appropriate.

We further note that while Mr. VanderHeyden's recommendation reflects a simple average of his DCF and CAPM, his ROE analysis does not precisely reflect the IRR and Risk Premium Buildup ("RP Buildup") methods performed in Case No. 9406. Mr. VanderHeyden explained that both IRR and RP Buildup methods "are impacted

[462] Pepco itself did not issue common stock; rather, its parent holding company, PHI, held all of the Company's equity.

significantly by current financial market conditions."[463] We find, however, that current market conditions would also have a significant impact on Mr. VanderHeyden's CAPM analysis.

On cross-examination regarding downward trends in ROE, Mr. VanderHeyden testified that "bond yields . . . have an impact in at least one of the methods . . . used [to estimate ROE]."[464] He observed that bond yields have been trending downward over time, which is consistent with the observations of Mr. Baudino and Dr. Woolridge. Mr. VanderHeyden further testified that had he incorporated current 2016 Treasury data into his analysis, it would have driven his CAPM result lower by as much as 20 or 30 basis points.[465]

We agree that current market conditions favor a cost of equity that is lower than Pepco's currently approved ROE of 9.62%. But how much lower? Historically, we have generally followed the principle of gradualism when implementing major rate design changes that have a potentially adverse impact on a particular class of customers. Gradualism prescribes that sudden and dramatic shifts in rate design should be avoided. We find that gradualism works both ways and would be appropriate in this instance to lessen the impact on the company and investors. Relative stability in rates is an important ratemaking goal—for ratepayers and utilities alike. As Mr. VanderHeyden explained regarding returns on equity, "[o]ne of the properties of our rate making process is that awarded ROEs do not instantly respond to market changes. Awarded ROEs

[463] VanderHeyden Surrebuttal at 6.
[464] Tr. at 1427.
[465] Tr. at 1430-31. Mr. VanderHeyden testified that on July 5, 2016, Yahoo! Finance reported 30-year U.S. Treasuries at 2.13%. VanderHeyden Direct at 15 n.13.

should make gradual movements."[466] Implementing gradual movement will "encourage an environment that does not surprise investors with changes that impact them adversely."[467]

An ROE of 9.55% is a two-basis point downward adjustment from Staff's recommendation. It also maintains Pepco's currently approved ROE after removing the previously awarded seven-basis point flotation adjustment. We believe the market can sustain this ROE. Dr. Woolridge testified that, on a national level, the average authorized ROE for electric utility and gas distribution companies is around 9.5.[468] For electric distribution companies specifically, the average authorized ROE was 9.39 percent for the first half of 2016.[469] It is unlikely, therefore, that the ROE we authorize today will scare investors or hurt Pepco's access to credit. Even when we reduced the Company's ROE in 2012, Pepco nevertheless generated $450 million in new long-term debt.[470]

We find that a return on equity of 9.55% for Pepco's electric distribution operations falls within the DCF, CAPM, and ECAPM ranges reported by Pepco witness Hevert, and, in particular, falls towards the upper end of his constant growth DCF range. This ROE further complies with the standards under *Bluefield* and *Hope*. It is comparable to the returns investors expect to earn on investments of similar risk in the current market. It is sufficient to assure confidence in Pepco's financial integrity and enable the Company to receive a fair return commensurate with its risk. It is further adequate to sustain Pepco's credit so that the Company can continue to attract needed

[466] *Id*. at 4.
[467] VanderHeyden Direct at 7.
[468] Woolridge Surrebuttal at 22.
[469] Woolridge Surrebuttal at 23.
[470] Case No. 9311, Order No. 85724 at 104.

capital in a low-interest rate environment and provide safe and reliable service to its customers.

When applied to its capital structure, Pepco's overall rate of return will be 7.49%, as shown in the following chart:

Type of Capital	% of Total Capital	Embedded Cost Rate	Weighted Cost Rate
Long-Term Debt	50.45%	5.48%	2.76%
Common Equity	49.55%	9.55%	4.73%
Total/Overall ROR	100.00%		7.49%

E. Cost of Service

1. Parties' Positions

Pepco presented its COSS and its class cost of service ("CCOSS") through the testimony of Mr. Nagle. Mr. Nagle's methodology in developing Pepco's COSS and CCOSS methods were consistent with prior Commission orders.[471] In fact, Staff Witness Norman recommended use of Pepco's jurisdictional COSS without modification.[472] However, Pepco's CCOSS continued to allocate 100% of AMI costs to those classes that received AMI meters.[473] Although Pepco's CCOSS was consistent with similar past cases accepted by the Commission, those cases did not fully address the new issues raised by AMI costs.

[471] Norman Direct at 2.
[472] Norman Direct at 2; Staff Initial Brief at 21.
[473] Tr. 1048-49 (Norman).

Rather than adopting Pepco's CCOSS, Ms. Norman proposed an alternate allocation for AMI costs across customer classes.[474] First, Staff observes that Pepco provided portrayals of the many benefits of AMI, including the significant "energy and demand management outcomes from which all customer classes benefit."[475] Only 25% of the AMI benefits are exclusive to classes receiving AMI meters. Therefore, Staff contends that Pepco is ignoring the claimed system-wide benefits when it allocates AMI costs only to classes that received meters.[476]

Pepco concedes that AMI may provide benefits across rate classes that may not align with the traditional cost-based allocation approach used for metering plant. However, it maintains that its approach remains superior to a benefits-based approach, which disregards cost causation.[477] Mr. Nagle testified that meters are installed for each customer based solely on the contingent that energy must be measured.[478]

Staff responds, persuasively in our view:

> Traditional meters were already providing measurements of customer consumption. If AMI was meant to provide only consumption measurement, no upgrade would have been cost justifiable. Pepco is not only demanding AMI customer classes pay for the consumption measurement they already had, but for the incremental costs that provide new benefits to all customer classes. The application of traditional strict cost causation criteria is no longer equitable when allocating this dynamic new technology; Residential and other AMI metered classes should not pay exclusively for system wide benefits.[479]

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[474] Norman Direct at 2. OPC urged the Commission to reject Pepco's COSS because OPC believed that Pepco failed to include a significant amount of data made available to it through AMI. OPC ultimately supported the adoption of the CCOSS described by Staff, as we have. OPC Initial Brief at 33-35.
[475] Staff Initial Brief at 22. *See also*, Leftkowitz Direct at 13, Table A, reproduced *supra*.
[476] Staff Initial Brief at 22.
[477] Pepco Initial Brief at 63; Nagle Rebuttal at 3.
[478] Nagle Rebuttal at 4.
[479] Staff Initial Brief at 22.

Instead, Staff proposes a hybrid approach that spreads AMI costs across all rate classes receiving benefits from AMI, but weights more heavily those classes that share in the additional benefits exclusive to those who actually receive an AMI meter.[480]

2. Commission Decision

In Case No. 9406, OPC's witness Wallach proposed a benefits approach for allocating AMI costs among rate classes. By allocating these costs on the basis of traditional cost causation principles rather than on the basis of expected benefits, he contended the ECOSS over-allocates costs to the residential class. Although we recognized that this approach had merit, we agreed with Staff Witness Norman that "an approach based on benefits is not viable in this proceeding given the lack of information." We stated that "with a more detailed analysis of the benefits approach allocation of costs, we may consider utilizing it in future rate cases."[481]

We believe there is sufficient information in the present case. Based upon the record before us, the weighted average proposed by Staff Witness Norman more equitably distributes the AMI costs we have approved in this case. As Ms. Norman explained, "to the extent that the incremental costs of AMI meters are incurred to support load shaping and conservation programs and goals, they could be classified and allocated accordingly."[482] To the extent that AMI costs are allocated based on demand or energy volumes, costs will rise for smaller customers and decline for larger customers.[483]

Table 11 of Ms. Norman's direct testimony describes the relative rate of return for each rate class based upon three allocation methodologies – Pepco's proposal as filed,

[480] *Id.* at 22-23.
[481] Case No. 9406 at 184.
[482] Norman Direct at 20.
[483] *Id.* at 21.

Demand based, and Energy based.[484] Ms. Norman proposes a weighted average allocation of these three results for AMI-related costs.[485] After calculating the relative rates of return pursuant to her proposed weighted average allocation, the proposed alternative allocation approach adjusts each class RROR to more accurately represent the costs and benefits of AMI plant. We believe Ms. Norman's hybrid approach most fairly spreads the costs and related benefits of AMI throughout the Pepco service territory.

F. <u>Rate Design</u>

Rate Design involves two functions: (1) the design of inter-class rates, which involves the assignment of revenue requirement between the various customer classes, and (2) the design of intra-class rates, which involves the manner in which the class revenue requirement will be collected from customers. In order to determine how much of any rate increase (or decrease) should be assigned to a particular customer rate class, we begin with the actual rates of return reflected in the jurisdictional cost of service (COSS). These results are then translated into a relative rate of return, which measures as a percentage the actual individual customer class rate of return compared to the utility's system average or overall rate of return.[486] An RROR of 1.0 signifies that a rate class has a return equal to the utility's overall rate of return. An RROR that is higher than 1.0 indicates that the class has a return (or contribution) that is greater than the system average, and an RROR that is lower than 1.0 indicates a class return that is less than average. If all customer rate classes have an RROR of 1.0, then each class is contributing equally to the utility's overall rate of return based upon its cost of service. As a matter of

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[484] *Id.* at 22.
[485] *Id.* at 22-23.
[486] *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*, Case No. 9326, 104 Md. P.S.C. 653, 699 (2013).

policy, the Commission strives to bring all classes closer to an RROR of 1.0 in each rate case, to reflect the cost causation from each class. However, this goal is also tempered with notions of gradualism in order to avoid rate shock from the customers of any particular rate class.

Once the revenue requirement is apportioned among the various classes, intra-class rates may be designed. Almost all rate classes have a customer charge, which is designed to recover fixed utility costs, such as the cost of meters. Additionally, Pepco customers have an energy charge, which is designed to recover variable costs. That is, each customer's bill has a fixed, monthly customer charge and volumetric, per-kilowatt hour ("kWh") charges. Intra-class rate design is guided by important policy considerations, including gradualism, energy conservation, economic impacts, as well as cost causation.

1. <u>Revenue Allocation</u>

The Commission has regularly employed a two-step process for the determination of inter-class rates. The two-step approach intends to balance the actual rates of return reflected in the company's COSS and the principle of gradualism.[487] The Commission has described this process as follows:

> We have developed a general policy of allocating rate increases using a two-step approach. *First*, a portion of the increase is allocated to under-earning classes to move their rates of return or URORs closer to the system average. In the second step, the remainder of any increase is apportioned to all customer classes based upon the proportion of their class revenues compared to overall system revenues.[488]

[487] The parties do not contest the proposed allocation of non-AMI costs. This order addresses only the allocation of AMI-related costs.
[488] Case No. 9286, *In Re Potomac Electric Power Co., 103 Md. PSC 293, 352 (2012).*

Step One

For the first step, Pepco has proposed a 25% allocation of the increased rates to residential and other under-earning classes.[489] Pepco Witness Janocha explains the rationale for this decision:

> 1) Limit the maximum percentage increase to any one of these rate schedules to 1.5 times the overall average percentage increase;
> 2) Ensure that the final proposed UROR for a rate class with an existing UROR above 1.0 does not increase, nor move to a level below 1.0;
> 3) Ensure that the final proposed UROR for a rate class with an existing UROR below 1.0 does not decrease nor move to a level above 1.0.[490]

Witness Janocha notes that this approach is consistent with prior orders by the Commission in Case Nos. 9331 and 9336.[491]

Staff testified that in this case an 18% allocation to under-earning classes is more equitable. Obviously, strict fairness to every ratepayer would require that every ratepayer have a RROR of 1.0, and analysts do their best to avoid inter-class subsidies. However, as Staff Witness Blaise explains, such an approach would regularly result in rate shock to one or more classes. Therefore, Staff proposes an 18% allocation to underperforming classes (R, RTM, and GS-LVR).[492] Witness Blaise explains this particular percentage by testifying that he ran "over fifty different scenarios" to determine the best allocation approach to recommend, and 18% "provided a balanced set of RRORs and allocation proportions. That is, it doesn't unduly strain any one class by allocating too much revenue towards any one class in an excessive manner."[493] Additionally, this percentage

[489] Janocha Direct at 6-7; Schedule (JFJ) – 1.
[490] *Id.* at 6
[491] *Id.* at 4.
[492] Blaise Direct at 17.
[493] Blaise Direct at 17-18.

is consistent with prior Commission cases in which the Commission determined a 15% allocation to be appropriate.[494]

We agree and adopt the 18% first step allocation recommended by Witness Blaise, which represents a more gradual movement toward system parity than Pepco's recommended 25%.

Step Two

The remaining 82% of the awarded revenue requirement increase should be allocated to all classes, except GT-3B and TN, as these classes are significantly over-earning.

2. Customer Charges

Customer charges intend to cover the costs incurred by a utility for fixed charges. As with allocating costs between rate classes, determining the proper ratio between customer, volumetric and demand charges requires balancing many competing variables. It is important that customers who cause certain costs incur those costs, but the principle of gradualism applies here as well. Additionally, policy concerns must also guide the Commission, such as energy conservation incentives and the effect of an increased surcharge on low income customers. With these principles in mind, we believe the record in this case supports a gradual increase in the customer charges.

Pepco proposes to increase the charge for its residential customers from its current $7.39 to $12.00.[495] This would represent a 62.38% increase, and Pepco's residential customers would be paying a customer charge far in excess of similarly situated customers in other Maryland service territories. For example, in Case No. 9406, we

[494] Case No. 9299, Order No. 85374 at 98.
[495] Janocha Direct at 8.

raised BGE's customer charge from $7.50 to $7.90.[496] Pepco frames this as a concession to gradualism, claiming that its COSS actually supports an increase to $22.85.[497]

Staff proposes that the Commission increase the customer charge for Pepco's residential customers from its current $7.39 to $7.85, a $0.46 increase.[498] Witness Blaise supports this recommendation in part by noting that a $7.85 charge "would not significantly change the proportion of revenue derived from fixed charges, which is currently 19.61%."[499]

OPC contends that we should not order any increase in customer charges, but rather let the residential customer charge remain at $7.39. In the alternative, OPC supports Staff's recommendation as a viable alternative to requiring additional information from Pepco.[500]

We believe an increase slightly lower than Staff's recommendation is appropriate in this case, and we have concluded that residential customer charges should increase to $7.60. Determining the appropriate increase is not an exact science, but rather the balancing of many considerations. In arriving at this increase, we place emphasis on Maryland's public policy goals that intend to encourage energy conservation. Maintaining relatively low customer charges provides customers with greater control over their electric bills by increasing the value of volumetric charges. No matter how diligently customers might attempt to conserve energy or respond to AMI-enabled peak pricing incentives, they cannot reduce fixed customer charges.

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[496] Order No. 87591 at 193. This represents a 5.3% increase.
[497] Janocha Direct at 8-9.
[498] Blaise Direct at 20. This would represent a 6.2% increase. OPC Initial Brief at 37.
[499] Blaise Direct at 20.
[500] OPC Initial Brief at 37.

Additionally, lower customer charges provide more value to net metering customers. The terms of most utility tariffs typically require a customer to pay the monthly customer charge regardless of the amount of energy produced. However, for energy billed, the customer pays only for energy that is used, netted against any generation produced by the customer.

With all of these factors in mind, we have determined to increase the residential customer charge from its current $7.39 to $7.60, approximately halfway between Staff's proposal ($7.85) and OPC's proposal (remaining at $7.39). As the chart below demonstrates, the customer charges paid by Pepco's residential customers remain comparable to similarly situated customers of other Maryland electric utilities:

Residential (R) Customer Charges in Maryland	
Company	**Monthly Customer Charge**
Choptank	$10.25
SMECO	$9.50
STATEWIDE AVERAGE	$8.00
Delmarva	$7.94
BGE	$7.90
PEPCO - Current	$7.39
PE	$5.00

An increase from $7.39 to $7.60 represents a 2.84% increase, and we have concluded that it is reasonable to raise the rates of other classes by a similar percentage.

This ruling will result in the following customer charges:

RS – $7.60
RTM – $16.31
GS-LV-$11.32
MGT-LV – $42.51
MGT-3A – $40.37
GT-LV – $345.42
GT-3B – $313.08
GT-3A – $324.33
TMRT – $3443.58

The average residential customer will see a 4.76% increase in their monthly bill or approximately $6.96. We believe this is reasonable in light of the significant investment Pepco has made in AMI and in improving reliability overall. We also wanted to emphasize the recent increase in customer control of their electricity consumption by minimizing the extent to which they are subject to fixed charges while balancing that goal with Pepco's right to recover its fixed customer costs.

3. <u>Volumetric and Demand Elements</u>

In its Reply Brief, AOBA contends:

> As initially proposed by Pepco, the Company would place increases ranging from 90% to 106% on these classes' demand charges.
>
> Thus, as reductions in kWh use and improved energy efficiency are state-wide goals in Maryland, Pepco's focus on increasing demand charges and eliminating volumetric charges for commercial customers is inconsistent with achievement of state-wide EmPOWER Maryland objectives.

In Order No. 85028 (Case No. 9286), we held that :

> On this record we find that the rate increase and any BSA assignment should be allocated to the customer, volumetric, and demand elements based upon the same percentage increase as the class percentage increase in rates. In our opinion, this strikes an appropriate balance between principles of cost causation and energy conservation. This allocation will essentially maintain the

> intra-class rate relationships as they exist today. Additionally, this allocation is consistent with principles of gradualism. Therefore, the Company is directed to file tariffs consistent with these findings. We also direct the Company to file an update to its COSS, which reflects the rate increase authorized herein and that shows the new class rates of return and the new unitized rates of return.[501]

After we determine the revenue requirement for each class (through the 2-step allocation methodology) and set the customer (fixed) charge, the utility recovers the remainder of the revenue through the class's energy and demand charges. Pepco proposes to recover all of the remaining revenue through the demand charge. However, we will affirm our prior ruling that the charges should be increased equally.

G. <u>Miscellaneous</u>

Staff recommended that the Company be required to implement a comprehensive reliability planning process which includes: a cost-benefit analysis of each of the Company's reliability programs; weather normalization of the Company's historical system reliability performance; and projection of the Company's overall system reliability performance based on the group of projects/programs being undertaken.[502] We agree with Pepco that Staff's recommendation "does not make the engineering and construction process more efficient or offer greater customer protections"[503] and do not accept Staff's recommendation of requiring a comprehensive reliability planning process at this time. Pepco witness Gausman noted that a cost benefit analysis is not needed to determine the value of reliability projects.[504] However, as pointed out by Mr. Gausman,

[501] Order No. 85028 at 130.
[502] Shelton Direct at 3.
[503] Gausman Rebuttal at 12.
[504] *Id.* at 14.

the Company is required to report its reliability as ordered by the Commission in Case No. 9240.[505]

Additionally, the Staff noted that Pepco's vegetation management cost per mile is high compared to other Maryland utilities and recommended Pepco to solicit vegetation cost management best practices from the other Exelon Utilities and actively re-structure the Company's vegetation management contracts in order to reduce cost. Staff also recommended that Pepco submit a quarterly vegetation management report to Staff. We agree that Pepco should seek out and employ best practices for vegetation management from other Exelon utilities. Additionally, we accept Staff's recommendation that Pepco submit a quarterly vegetation management report to Staff with the components outlined by Staff witness Shelton in her direct testimony.[506]

Staff also noted that Pepco is adjusting the restoration time for customer outages if AMI data shows a restoration time earlier than what the crew entered as the restoration time. However, it did not appear that Pepco was making a systematical adjustment to show if the meter shows a time later than what the crew entered. We accept Staff's recommendation that Pepco make use of AMI meters to accurately adjust restoration time, but also direct the Staff to form a working group to review the current practice in more detail.

Last, we urge Pepco to evaluate "non-wires" alternative resources, like demand response, energy efficiency, storage, and other smart grid resources, as part of any assessment of proposed substantial distribution system investments.

[505] *Id.* at 17.
[506] Shelton Direct at 3.

IV. CONCLUSION

Based upon our review of the record in this case, we find that the Application filed on April 19, 2016, by Potomac Electric Power Company for a rate increase of $126,784,000 will not result in just and reasonable rates and is therefore rejected. Instead, we find that based on a test year of the twelve months ending December 31, 2015, as adjusted above, the Company is authorized to file revised rates and charges for an increase in revenues of $52,535,000, which amount will result in just and reasonable rates to the Company and its customers. As allocated, the increase in the overall residential bill will be approximately 4.76%, which is $6.96 per month on average. The Company shall file revised tariffs for such increase in accordance with the rate design and other decisions in this Order.

IT IS THEREFORE, this 15th day of November, in the year Two Thousand and Sixteen, by the Public Service Commission of Maryland,

ORDERED: (1) That the Application of Potomac Electric Power Company filed on April 19, 2016, seeking to increase distribution rates for electric service by $126,784,000 in its Maryland service territory, is hereby denied;

(2) That Potomac Electric Power Company is hereby authorized, pursuant to § 4-204 of the Public Utility Companies Article, *Annotated Code of Maryland,* to file tariffs for the distribution of electric energy in Maryland, which shall increase rates by no more than $52,535,000, for service rendered on and after November 15, 2016, subject to acceptance by the Commission; and which shall otherwise be consistent with the findings of this Order;

(3) That Pepco is hereby required to file a Distribution Investment Plan within twelve (12) months of the date of this Order that sets forth how the Company will accomplish its T&D goals, analyzing in detail the Company's strategy over the next five years for

investing in its distribution system including, among other things, specifics about how the Company's investment in smart meters will be utilized to improve the efficiency and effectiveness of the distribution network;

(4) That Pepco is hereby required to continue to provide Staff with detailed metrics including incremental costs and benefits, budgets, performance of the AMI system, cybersecurity and other important aspects of the operation of the AMI system as set forth in Order No. 83571; and

(5) That all motions not granted herein are denied.

/s/ W. Kevin Hughes

/s/ Harold D. Williams

/s/ Jeannette M. Mills

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell
Commissioners

POTOMAC ELECTRIC POWER COMPANY
CASE 9418

Revenue Requirement
($000's)

Rate Base	$	1,636,944
Rate of Return		7.49%
Required Income	$	122,607
Adjusted Income	$	91,967
Income Deficiency	$	30,640
Conversion Factor		58.32%
Revenue Requirement	**$**	**52,535**

Rate Base
($000's)

Per Books Balance	$	1,596,664
Uncontested Adjs.	$	(7,659)
Uncontested Balance	**$**	**1,589,005**
Annualization of Test Year Reliability Plant Closings	$	20,664
Post Test Year Reliability Closings (Jan thru Aug 2016)	$	15,514
AMI Regulatory Asset Amortization	$	29,188
Reflection of 50% SERP Liability and Expense	$	(9,826)
Winter Storm PAX	$	366
Winter Storm Jonas	$	926
Reflection of Synergies and CTA	$	8,704
NOLC Adjustment	$	(17,155)
Billing System Transition Costs	$	3,906
Pro Forma Impact to Cash Working Capital Allowance	$	(4,347)
Adjusted Rate Base	**$**	**1,636,944**

APPENDIX II

POTOMAC ELECTRIC POWER COMPANY
CASE 9418

Operating Income
($000's)

Per Books Balance	$	97,241
Uncontested Adjs.	$	(9,380)
Uncontested Balance	**$**	**87,861**
Annualization of Test Year Reliability Plant Closings	$	(2,027)
Post Test Year Reliability Closings (Jan thru Aug 2016)	$	(3,053)
AMI Regulatory Asset Amortization	$	(3,768)
Legacy Meter Regulatory Asset Amortization	$	(5,049)
Tax Compensation Carrying Costs	$	1,890
Annualization of Wage Increases	$	(1,554)
Exclusion of Executive Incentive Costs	$	1,789
Reflection of 50% SERP Liability and Expense	$	2,154
Winter Storm PAX	$	(81)
Winter Storm Jonas	$	(206)
Reflection of Synergies and CTA	$	3,439
Restate Deferred Storm Costs	$	2,065
OT Adjustment	$	1,234
Outside Legal	$	149
Outside Professional	$	133
Annualization of Late Payment Revenues	$	321
Billing System Transition Costs	$	3,472
Legacy Billing Costs	$	425
Tax Effect of Proforma Interest Expense	$	449
AFUDC Synchronization	$	2,324
Net Operating Income	**$**	**91,967**

ORDER NO. 88033

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR ADJUSTMENTS TO ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9424

Issue Date: February 15, 2017

To: Parties of Record and Interested Persons

On July 20, 2016, Delmarva Power & Light Company ("Delmarva" or the "Company") filed with the Maryland Public Service Commission ("the Commission") a request to increase its electric distribution rates in the amount of $56,970,183.[1] The Commission docketed the matter and delegated it to the Public Utility Law Judge Division for consideration. On January 4, 2017, the Chief Public Utility Law Judge ("Chief Judge") issued a Proposed Order authorizing a maximum increase of $34,100,454 in Delmarva's electric distribution rate base, based on an authorized return on equity ("ROE") of 9.48%, and findings regarding the Company's: 1) Advanced Metering Infrastructure ("AMI") deployment; 2) rate base operating income and expenses; 3) depreciation rates; 4) cost of service; and 5) rate design.[2] On January 18, 2017, before the Proposed Order became final, Delmarva and the Maryland Office of

[1] Delmarva last filed an application to increase its rates in March 2013, prior to its parent Pepco Holdings, Inc.'s merger with Exelon Corporation.
[2] The Proposed Order also addresses other issues, such as the continuation of Delmarva's grid resiliency plan, storm costs, and reliability reporting.

People's Counsel ("OPC") noted their respective appeals and concurrently filed their supporting memoranda. Neither the Commission's Technical Staff ("Staff") nor the Maryland Energy Group – North East and Hanover Foods Company (together "MEG") filed any notice of appeal. All four parties filed reply briefs on February 1, 2017.

I. <u>The Parties' Issues on Appeal</u>

A. <u>Delmarva</u>

Delmarva appeals the Proposed Order and asks the Commission to reject the Chief Judge's findings with respect to: 1) the Company's authorized ROE; 2) the treatment of merger synergy savings and costs-to-achieve associated with the merger of Pepco Holdings, Inc. ("PHI") and Exelon Corp. in 2016; 3) depreciation-related issues concerning net salvage rates and the rebalancing of depreciation reserves; and 4) benefits associated with the Company's AMI system.

First, Delmarva contends that the ROE adopted by the Proposed Order is inconsistent with Commission precedent, given that the Commission has consistently identified a higher risk associated with a utility's electric operations as compared to its gas operations. Delmarva further avers that the authorized ROE is unsupported by the record and fails to consider the recent increase in the federal interest rates.

Second, Delmarva argues that the Proposed Order is inconsistent with Commission precedent favoring the symmetrical treatment of merger synergies and costs to achieve. Delmarva also argues that the Proposed Order's asymmetrical approach violates the known and measurable requirement.

Third, Delmarva claims that the Chief Judge's determination regarding net salvage rates should be reversed. Delmarva argues that it met its burden of proof to support its proposed net salvage rates. The Company further argues that it should have been allowed to rebalance its depreciation reserves in light of "significant changes in depreciation that necessitate a rebalancing."

Lastly, Delmarva objects to the Proposed Order's exclusion of non-core AMI benefits presented by Delmarva regarding market efficiency improvements in determining if AMI is cost-beneficial. Delmarva also alleges a calculation error in the Chief Judge's finding with respect to the value of capacity mitigation for Dynamic Pricing ("DP").

B. <u>OPC</u>

OPC appeals the Chief Judge's decision in the Proposed Order, alleging error in the following respects: 1) the finding that Delmarva's AMI program was cost-effective;[3] 2) the exclusion of only 50% of the Company's Supplemental Executive Retirement Plan ("SERP") costs; and 3) the adoption of Staff's recommended ROE of 9.48% instead of OPC's recommended ROE of 8.60% or one in between the two recommendations.[4]

First, OPC claims that the record in this matter does not support the finding that Delmarva's AMI program is "cost-effective." OPC argues that the Chief Judge mistakenly included the avoided transmission and distribution ("T&D") expenditures related to Dynamic Pricing (hereinafter "DP T&D") in her benefit-to-cost ratio, where the

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[3] For the purposes of this Order, the Commission will address the "cost-effectiveness" of AMI in terms of whether the program is cost-beneficial.
[4] OPC Mem. on Appeal at 1-2 (hereinafter "OPC Appeal at ___").

text indicates she intended to include only the avoided T&D costs related to the Energy Management Tools ("EMT") program (hereinafter "EMT T&D"). OPC also contends that the Chief Judge improperly included the benefits associated with EMT and excluded the costs associated with Dynamic Pricing. According to OPC, correcting these errors would reduce the benefit-to-cost ratio from 1.15 to 0.56.[5]

Next, OPC argues that the Proposed Order should have disallowed 100% of Delmarva's costs associated with its SERP program to maintain consistency with the Commission's recent treatment of Pepco's SERP-related costs in Case No. 9418. OPC notes that Delmarva adopted substantially similar arguments as Pepco and similarly failed to demonstrate why it should be allowed to recover all of its SERP costs.

Lastly, OPC avers that the Proposed Order fails to provide a valid reason other than "gradualism" for giving less credence to OPC's ROE analysis. Instead, OPC objects to the Chief Judge's decision to adopt Staff's allegedly "result-oriented approach" in reaching an ROE close to 9.5%.[6]

We discuss the parties' arguments and responses in the appropriate sections below. Additionally, we address *sua sponte* two findings in the Proposed Order pertaining to: 1) the adjustment for 8 months of post-test year reliability plant costs; and 2) the increase in customer charges. For the reasons stated herein, we affirm in part the Proposed Order, except with respect to: 1) the Company's authorized ROE; 2) capacity pricing mitigation; 3) disallowance of Delmarva's SERP costs; and 4) the customer

[5] OPC Appeal at 4.
[6] *Id.* at 17.

charges. We hereby modify the Proposed Order accordingly, and the Proposed Order shall be entered as final subject to the modifications stated herein. Our decisions on appeal authorize Delmarva a total revenue increase of no more than $38,267,710 to take effect on February 15, 2017.[7]

II. **Commission Decision**

C. AMI Deployment

Delmarva and OPC each appeal findings in the Proposed Order related to the Company's AMI deployment. Specifically, OPC objects to the Chief Judge's determination that Delmarva's AMI system is cost-beneficial. Delmarva, on the other hand, agrees with the cost-beneficial conclusion but argues that the Chief Judge failed to follow the Commission's historic method of calculating Dynamic Pricing capacity mitigation and should have also included calculated non-core AMI benefits from wholesale market improvements. We address these arguments in turn.

1. Cost-effectiveness of AMI

OPC claims that the Chief Judge erroneously included the avoided T&D costs derived from Delmarva's Dynamic Pricing program as an AMI benefit instead of the avoided T&D costs derived from its EMT program. OPC cites language in the Proposed Order expressly adopting Staff's calculation, which according to the Order included only

[7] Attachments I and II to this Order reflect our adjustments to Delmarva's net operating income, rate base, and revenue requirement.

EMT T&D costs and not DP T&D.[8] Delmarva disagrees and counters that the error in question is due to a scrivener's error in the Proposed Order—namely, where the Chief Judge referenced EMT T&D in her reasoning, the language should refer to DP T&D.[9] Delmarva explains that Staff's calculation, as corroborated by Staff Witness Hurley, includes DP T&D costs and not EMT T&D.

We find that Mr. Hurley's testimony supports Delmarva's explanation. Mr. Hurley described Staff's calculation as follows:

> The net present value for T&D is $18 million related solely to demand reductions related to the dynamic pricing program. Staff has excluded the Avoided T&D for the CVR and EMT programs from the Core benefit analysis.[10]

While we agree with Delmarva that the language on page 35 of the Proposed Order referring to EMT T&D should refer instead to DP T&D, this error is harmless. The AMI benefits calculation later reflected on page 42 of the Proposed Order correctly includes the calculated DP T&D benefits, as intended by Staff. Furthermore, even if we were to adopt OPC's proposed adjustment to align the language of the Proposed Order, the total benefit-to-cost ratio would be adjusted from 1.15 to 0.98, all else remaining equal. In our view, a ratio of 0.98 would be considered "break-even" and cost-beneficial, especially given OPC's position in a recent rate case that a benefit-to-cost ratio of 0.99 was close enough to be deemed cost-beneficial.[11] As the Chief Judge observed in the

[8] OPC Appeal at 6 (citing Proposed Order at 35).
[9] Delmarva Reply Mem. on Appeal at 5 (hereinafter "Delmarva Reply Mem. at ___").
[10] Staff Ex. 18 (Hurley Direct) at 27.
[11] *See* Case No. 9418, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Order No. 87884, at 19-20 (Nov. 15, 2016).

Proposed Order, we have not required utilities to establish a particular cost-benefit ratio, only that they demonstrate that their system is cost-beneficial—a pass/fail proposition. We need not address specifically whether Delmarva, Staff or OPC has provided a cost-benefit ratio closer to our own liking because doing so would be a moot analysis. Rather, we simply agree with the Chief Judge that Delmarva has "passed the test."

OPC contends, however, that further reductions in calculated benefits are warranted insofar as Delmarva's EMT load reductions can be achieved without AMI. Where OPC has asserted the same argument in other rate cases involving AMI recovery, we have consistently denied this argument. This case is no different. Here, the Chief Judge concluded, based on the record, that Delmarva's EMT program adds value to customers and enables them to save more energy.[12] Moreover, the various energy conservation tools provided under the program are not supported by legacy meters.[13] We see no reason to disturb the Chief Judge's findings.

Similarly, we are not persuaded by OPC's argument that the costs of credits paid in Delmarva's Peak Energy Savings Credit ("PESC") program should be included in our cost-benefit analysis. Despite renewing this argument in Delmarva's case, OPC did not offer any new evidence or argument to distinguish this case from the other rate cases previously decided by this Commission. Where OPC relies on the prior reports of Company witness Faruqui, we find that its interpretation of Dr. Faruqui's previous statements is incorrect, inapposite and contradicted by Dr. Faruqui's specific testimony in

[12] Proposed Order at 31-32.
[13] *Id.*

this case. For the aforementioned reasons, we deny OPC's appeal with respect to the cost-effectiveness of Delmarva's AMI deployment.

Although we hold that Delmarva has "passed" the cost-benefit test for AMI deployment, we are also mindful of the economic impact the additional cost of AMI will have on the monthly distribution bills of Delmarva's residential and commercial customers. These customers will want and anticipate concrete savings and value added by their new meters. Accordingly, we expect that Delmarva will continue to demonstrate and communicate to its customers that the AMI program will result in direct monetary benefits and continue to develop ways to increase the types and amounts of such benefits that customers can receive in the future.

We continue to believe AMI has great potential to give customers access to information, control, and cutting-edge services, some of which may be supplied by innovative third parties. As we indicated to BGE and Pepco in awarding their cost recovery for AMI, we will remain vigilant with regard to Delmarva fully utilizing smart grid technology to optimize its AMI investment. We expect the Company to ensure that its customers will realize a demonstrable return on their investment in smart grid innovation. We look forward to reviewing the Company's progress on this important customer issue.

2. Dynamic Pricing

The Proposed Order provides that Delmarva's calculation of capacity mitigation for Dynamic Pricing[14] is overstated, due to certain changes in PJM wholesale market

[14] Delmarva's Peak Energy Savings Credit Program utilizes AMI-enabled Dynamic Pricing to empower residential customers to earn $1.25 for each kWh reduced during select summer hours of high electricity

rules that will reduce revenue from the program after May 2020.[15] As a result of this finding, the Chief Judge rejected Delmarva's capacity mitigation calculation and accepted the alternative calculation proposed by OPC witness Chernick. In its Appeal, Delmarva argues that the Chief Judge erred by utilizing OPC's alternative capacity mitigation calculation because it has not been approved by the Commission.[16] In contrast to OPC's methodology, Delmarva observes that its capacity mitigation value was based upon calculations approved by the Commission in several prior proceedings. Delmarva concludes that if the Commission agrees with the Chief Judge that Dynamic Pricing benefits should be excluded after May 2020, the Commission should utilize the Company's properly calculated values up until the year 2020 and then exclude the benefits thereafter. Staff similarly states that the capacity mitigation calculations entered into the record by Staff and Delmarva witnesses were based on the methodology approved in the Commission's EmPOWER Maryland cases and reaffirmed in subsequent proceedings.[17]

We agree with Delmarva that the Proposed Order should have utilized the methodology employed by the Company and Staff in calculating Dynamic Pricing capacity mitigation benefits up until 2020. While we do not disturb the Chief Judge's finding that Delmarva has not sufficiently demonstrated Dynamic Pricing benefits after the year 2020 to quantify them for purposes of our cost-benefit analysis, the Proposed Order should have adopted the capacity mitigation methodology approved by the

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demand. DPL Ex. 5 (Lefkowitz Direct) at 4. All Delmarva residential customers with activated AMI meters became eligible for the PESC Program during the summer of 2014. *Id*. at 48.

[15] Proposed Order at 38.

[16] Delmarva Mem. on Appeal at 19 (hereinafter "Delmarva Appeal at ___").

[17] Staff Reply Mem. at 13.

Commission for capacity mitigation benefits up until that year. The Commission approved the calculation in the EmPOWER Maryland cases[18] and reaffirmed the use of the methodology in BGE's most recent rate case.[19] Furthermore, the Commission recently denied OPC's Petition for Rehearing challenging the reasonableness of the methodology, finding that the calculation was not based on unreasonable assumptions.[20] Utilizing the Commission-approved methodology for calculating the value of capacity price mitigation benefits until 2020 increases the AMI benefit by $8,314,000 on a net present value basis.

3. Non-Core AMI Benefits

Delmarva argues on appeal that the Chief Judge failed to consider certain non-core AMI benefits—namely, wholesale market efficiency improvements arising from AMI-enabled hourly energy market settlements—in her overall calculation of AMI benefits.[21] According to Delmarva, these hourly settlements will lead to "reduced pricing hedge premiums and lower prices for Maryland customers," a benefit purportedly valued at $27.1 million on a net present value basis.[22] OPC in its Reply objects to these benefits, arguing that Delmarva waited until the evidentiary hearing to introduce the asserted benefits and that the Company's analysis was skewed.[23]

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[18] *See* Order Nos. 87082 and 87213.
[19] Case No. 9406, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*, Order No. 87591 at 61 (Errata) (June 3, 2016) (rejecting OPC's proposal to use a different methodology for measuring capacity price mitigation benefits and highlighting the importance of using "consistent methodologies across energy conservation and demand response programs").
[20] Case No. 9153, *In the Matter of the Potomac Edison Company d/b/a Allegheny Power's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008*, Order No. 87213 (Oct. 26, 2015).
[21] Delmarva claims that neither Staff nor OPC credibly challenged these benefits and the Company's calculations until their reply briefs filed after the evidentiary hearings. Delmarva Appeal at 17-18.
[22] Delmarva Appeal at 17.
[23] OPC Reply Mem. at 9-10.

Because we have already determined that Delmarva's AMI program is cost-beneficial, and therefore has "passed the test," it is unnecessary to further quantify the Company's purported benefits from market efficiency improvements. We nonetheless continue to urge our utilities to find non-core benefits associated with AMI.

D. Rate-making Adjustments

1. Merger Synergy Savings and Costs-to-Achieve

Delmarva claims that the Proposed Order abandons our "historical symmetrical treatment of merger synergies and costs-to-achieve" by adopting Staff's recommended adjustment, which purportedly creates an asymmetrical, annual "average net savings" derived from the estimated synergy savings from the first five years (post-merger) and a portion of actual and future costs to achieve.[24] Delmarva further argues that this approach "ignores the [Commission's] long standing position on known and measurable costs" in view of the fact that the Commission found those same synergies insufficiently reliable to constitute a benefit in the PHI-Exelon merger proceeding.[25] Lastly, Delmarva contends that Staff selectively excluded $1 million of costs-to-achieve, and its recommended adjustment would "result in a reduction of revenues which would exceed the expected merger savings in the early years of the five-year review period."[26] In the alternative, if the Commission affirms the Proposed Order on this issue, Delmarva requests clarification with regard to amortizing the total merger costs and savings over five years and approval to establish a regulatory asset to track merger costs and savings benefits.

[24] Delmarva Appeal at 10.
[25] *Id*.
[26] *Id*. at 11.

OPC in its Reply argues that while the Company incurs costs-to-achieve before the rates in this case go into effect, synergy savings are also being realized.[27] Specifically, Delmarva will realize approximately one year of synergy savings—or $2 million—prior to the rate effective date. Moreover, OPC notes that the synergy savings were promised in the merger case as a condition of our approval of the merger.[28]

Staff argued in the below proceeding that the Company's adjustment "tends to backload the projected synergy savings and front load the [costs-to-achieve]."[29] In view of this argument, the Chief Judge rejected the Company's adjustment in favor of Staff's.[30] We agree. The adjustment adopted in the Proposed Order is the one that will best ensure that Delmarva ratepayers receive the same levelized savings irrespective of when the Company files its next rate case. Furthermore, as noted in the Proposed Order, this approach comports with our treatment of the same synergy savings and costs-to-achieve for Pepco in Case No. 9418. The Chief Judge did not find "any evidence in this record to make a ruling different than that of the Commission in Case No. 9418."[31] Likewise, on appeal, Delmarva has not persuaded us otherwise. Accordingly, we affirm the Proposed Order on this adjustment.

With regard to Delmarva's request in the alternative for "clarification regarding the mechanism for compliance to amortize the total merger costs and savings over five years[,]" we look to the Proposed Order and note, as OPC did in its Reply, that Staff did not amortize the total merger costs and synergy savings over five years. Instead, Staff

[27] OPC Reply Mem. at 2-3.
[28] *Id*. at 3.
[29] Proposed Order at 60 (citing Staff Initial Brief at 13).
[30] *Id*. at 61.
[31] *Id*.

averaged the synergy savings over five years. Thus, we find no further clarification on this point is needed.

2. SERP

On appeal, OPC argues that the Proposed Order erred in limiting the disallowance for SERP expense to only 50% "for due process reasons."[32] The Chief Judge adopted Staff's and OPC's original recommendations for 50% disallowance and noted that Staff and OPC later changed their positions and recommended 100% disallowance in their initial briefs, filed after the conclusion of the evidentiary hearing in this matter. The Chief Judge approved the 50% reduction, explaining that "this is the amount that Delmarva knew could be disallowed based on the evidence in the record at the close of the evidentiary hearing."[33]

OPC disagrees with the Chief Judge's finding that no prior "admonition" had been made to Delmarva prior to this case that SERP expenses would remain an evolving issue for future resolution. Instead, OPC contends that Delmarva's parent company, PHI, "was on *actual* notice of the Commission's admonition about SERP costs."[34] Notice was therefore imputed to the Company because Delmarva is a subsidiary of PHI. Delmarva supports the Chief Judge's decision and reasoning.

We find that OPC's reasoning sufficiently addresses the notice and due process

[32] *See* OPC Appeal at 13-14.
[33] Proposed Order at 69-70.
[34] OPC Appeal at 14 (original emphasis); *see also* Case No. 9336, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Order No. 86441, at 59-60 (July 2, 2014) (noting that other neighboring jurisdictions had already disallowed 100% of SERP expenses and stating that "the appropriate funding of SERP costs continues to be an evolving issue that [the Commission] will continue to review in future cases").

concerns raised in the Proposed Order. As stated in the Proposed Order, Delmarva's SERP expenses "flow from the very same PHI SERP that applies to the PHI and Pepco executives" and are "no different than those incurred by its sister company, Pepco."[35] Given that both Delmarva and Pepco use the same PHI SERP plan, notice to PHI that the Commission's disallowance could be 100% placed Delmarva on constructive notice that it would be required to demonstrate that its SERP program offered direct benefits to Maryland ratepayers. This is consistent with our treatment of Pepco's SERP costs in Case No. 9418.

In Case No. 9418, we disallowed 100% of Pepco's SERP-related costs largely because Pepco failed to meet its burden of proof.[36] Here, the Chief Judge assessed and reached the same conclusion as to Delmarva. There is no evidence in the record to support the Company's contention that it or PHI would not be able to attract highly qualified executives without offering SERP as part of the executive compensation package. Like Pepco, the Company failed to provide any analysis to support its position on this adjustment. Based on these findings, we agree with the Chief Judge in conclusion only that Delmarva has not met its burden of proof. However, we do not see why Delmarva's ratepayers should bear any portion of the Company's SERP expenses. Accordingly, and in keeping with our recent decision concerning the same flow-down benefit, we grant OPC's appeal on this issue and modify the Proposed Order to disallow 100% of Delmarva's SERP-related costs.

[35] Proposed Order at 68.
[36] In Case No. 9418, the Commission also considered the fact that two neighboring jurisdictions—D.C. and Delaware—similarly disallowed 100% of Pepco's SERP-related costs. Order No. 87884 at 53.

3. Post Test-Year Reliability Plan Adjustment

In the Proposed Order, the Chief Judge accepted for the rate-effective year two uncontested adjustments pertaining to reliability plant additions. Adjustment No. 14 adjusts the rate base for plant additions related to distribution reliability through the end of the historical test period, or March 31, 2016. Adjustment No. 15 adjusts the reliability plant balances for another eight months, post-test period, through November 2016. While no party appeals the Proposed Order's reliability plant adjustments, we find it appropriate to briefly clarify post-test period reliability plant recovery (Adjustment No. 15) in light of our continued emphasis on the historic test year requirement.

It is true that we have made exceptions to our historic test period methodology in prior rate cases to allow limited recovery of post-test period reliability investments made and placed into service prior to the evidentiary hearings. Although we do not disturb the finding of the Chief Judge, it should be clearly understood by the parties that the Commission is not abandoning the test year requirement. As we have stated in other rate cases, allowance of post-test period reliability expenses is an *exception* to the rule of allowing recovery only of reliability investments for the historical test period. We departed from traditional ratemaking principles in order to incentivize companies that exhibited poor reliability performance to make the necessary reliability infrastructure investments in an accelerated manner without having to wait until the next rate case. We never intended for this exception to be deemed as guaranteed or automatic. Hence, we will continue to closely examine these requests on a case-by-case basis. Moreover, we expect the same scrutiny by the utility companies, Staff and OPC in future rate matters.

E. Depreciation

1. Net Salvage

The Chief Judge concluded that Delmarva failed to meet its burden of proof with regard to its net salvage accrual rates, given that the Company used proprietary software to calculate results that the other parties could not reproduce.[37] On appeal, Delmarva disputes this finding and argues that the Company disclosed the applicable formulas and supporting calculations for its net salvage accrual rates, consistent with the Commission's statement in Case No. 9096 that supplying the formulas was adequate. Thus, according to Delmarva, all parties had access to the information needed to duplicate the Company's net salvage accrual rates. OPC disagrees with this contention and further distinguishes the facts of Case No. 9096 from this case, arguing that Staff's witness in the former disclosed substantially greater information:

> In Case No. 9096, [Staff's witness] provided, in a filed schedule, a complete calculation of the [Statement of Financial Accounting Standards No.] 143 net salvage calculations for one account, showing the complete formulae for each individual column in a spreadsheet calculating SFAS 143 present value net salvage.[38]

Although Delmarva contends that it has satisfied its burden of proof simply by providing formulas and calculations supporting its rates, we disagree. As the Chief Judge correctly stated in the Proposed Order, the Company "has the burden of proof to justify any costs for which it seeks recovery from ratepayers" and, therefore, "has the burden to demonstrate the accuracy of its analysis, including how it arrived at its recommended net

[37] Proposed Order at 100.
[38] OPC Reply Mem. at 5.

salvage accrual rates."[39] We share the Chief Judge's concern that Delmarva chose to rely on proprietary software for its rates. Use of such software impairs our ability to test the Company's data. While Delmarva may have provided key formulas and calculations to the parties, the reality is that no one else was able to replicate the Company's results, including Staff.[40] Because Delmarva has not convinced us that it has satisfied its burden of proof, we deny the Company's appeal on this issue.

2. Rebalancing Depreciation Reserves

Delmarva also argues that the Chief Judge improperly denied its request to rebalance the depreciation reserve accounts when, according to the Company, rebalancing is necessary because of "significant changes impacting depreciation" since the last rebalancing in 2012. Delmarva refers to certain changes directed by the Commission in Case No. 9285,[41] wherein the Commission reviewed for the first time Delmarva's implementation of SFAS 143 present value net salvage calculations since the Commission changed methods for estimating future net salvage in Case No. 9093.[42]

We have generally opposed rebalancing depreciation reserves unless there have been significant changes that have occurred in recent cases affecting both depreciation rate formulations and account reserves. In Case No. 9285, we agreed with Delmarva that significant changes had occurred—namely, the implementation of the Present Value

[39] Proposed Order at 100.

[40] OPC argues in its Reply that Delmarva failed to reveal the SFAS 143 calculations themselves. OPC Reply Mem. at 5.

[41] *See generally* Case No. 9285, *In the Matter of the Application of Delmarva Power & Light Company for Authority to Increase its Rates and Charges for Electric Distribution Service*, Order No. 85029 (July 20, 2012).

[42] In Case No. 9093, the Commission addressed how future net salvage should be estimated for Delmarva, rejecting the Straight-Line Method in favor of the Present Value Method. *See* Case No. 9093, *In the Matter of the Application of Delmarva Power and Light Company for Authority to Revise its Rates and Charges for Electric Service and for Certain Rate Design Changes*, Order No. 81518, at 17 (July 19, 2007).

Method—which affected both depreciation rate formulations and account reserves. We held that under those circumstances "it [was] appropriate to rebalance depreciation account reserves prospectively in order to align those reserves with expected future retirements and salvage accruals."[43] We cautioned, however, that "it may not be necessary or appropriate in every instance to adjust account reserves."[44]

In the Proposed Order, the Chief Judge found that rebalancing was unnecessary in this instance given that there have not been any significant changes since 2012 to justify rebalancing.[45] We agree. Delmarva does not recommend or indicate any recent changes to the previously approved depreciation system.[46] Instead, the Company generally notes our methodology requirements in Case No. 9285, the passage of time since the last rebalancing, and certain parameter adjustments proffered by Company Witness White. However, the mere passage of time and general compliance with our Present Value Method requirement do not, by themselves, reflect the type of significant changes in the Company's depreciation accounting that would warrant adjusting account reserves. We therefore deny the Company's appeal on this issue.

Lastly, Delmarva brings to our attention a discrepancy between the Chief Judge's acceptance of Staff's recommended net salvage rates and the subsequent denial of the Company's request to rebalance the depreciation reserves. According to Delmarva, Staff did not object to Dr. White's redistribution of the Company's depreciation reserves in his 2015 depreciation study. Instead, Staff based its recommended net salvage rates, in part,

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[43] Order No. 85029 at 55.
[44] *Id*.
[45] Proposed Order at 106.
[46] Proposed Order at 103.

on those rebalanced reserves.[47] To resolve the conflict, Delmarva asks the Commission to adopt the Company's formulation of net salvage accrual rates. OPC does not dispute the discrepancy but recommends that the Commission direct Staff to recalculate its net salvage rates based on recorded book depreciation reserves instead of Dr. White's rebalanced reserves. Staff does not take a position. Delmarva and OPC agree that the "correct" formulation of net salvage accrual rates—i.e., one that excludes the impact of rebalancing reserves—is not in the record of this proceeding.

Our decision to affirm the Chief Judge's denial of Delmarva's rebalancing request does not directly bear on Staff's net salvage rate calculations but, rather, implicates Staff's depreciation rates, which according to Staff Witness Smith were based on Dr. White's theoretical rebalancing of depreciation reserves. Mr. Smith testified that he used the approved SFAS 143 Present Value Method to develop his recommended net salvage rates and used the net salvage percentages proposed in Dr. White's depreciation study.[48] Mr. Smith did not use Dr. White's proposed rates and amounts. It is only with regard to Staff's depreciation rates that Mr. Smith stated he used Dr. White's redistributed reserve calculations to calculate his own redistributed reserve amounts.[49] The Chief Judge voided Dr. White's rebalanced reserve calculations, however, which we affirm on appeal. Whereas the record of this proceeding does not discuss the formulation of rates without the rebalancing of the reserve accounts, we believe that the appropriate calculation of depreciation rates, in view of the rebalancing denial, should be based on the Company's recorded book depreciation reserves.

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[47] Delmarva Appeal at 16.
[48] Staff Ex. 24 (Smith Direct) at 4.
[49] Smith Direct at 9.

On appeal, Delmarva provides "corrected" depreciation rates for Staff, based upon book depreciation reserve amounts.[50] We find these revised depreciation rate calculations sufficiently resolve the conflict in the Proposed Order. Under the revised rates, Delmarva's depreciation adjustment increases to $4,628,734. This in turn reduces the Company's net operating income and increases its total revenue requirement.[51]

F. Return on Equity

Delmarva and OPC separately allege that the Chief Judge improperly set Delmarva's ROE at 9.48%, a 33-basis point reduction from the Company's current ROE of 9.81%. Delmarva argues that the authorized ROE is inconsistent with purported Commission precedent recognizing that "a utility's electric operations present a slightly elevated risk to investors compared to natural gas operations, and investors in the electric utility will therefore require a slightly higher return to compensate for that risk."[52] Delmarva further argues that a 30-basis point reduction in its ROE is further inconsistent with the Commission's emphasis on gradualism and recent increases in short-term and long-term interest rates.[53]

OPC argues that the Chief Judge erred in adopting Staff's recommended ROE, which OPC Witness Woolridge criticized as "results-oriented." OPC also objects that the Proposed Order gave less credence to Dr. Woolridge's analysis and testimony that

[50] *See* Delmarva Appeal, Attachment B.
[51] In finalizing the Order, we noted that a typographical error occurred in the exhibits in the record related to calculating the annualized depreciation expense. In some instances, the net salvage value was not added to the plant accrual rate; thus, the revenue requirement in the Proposed Order was approximately $4 million too low, which we correct herein.
[52] *See* Delmarva Appeal at 3 (quoting Case No. 9299, *In the Matter of the Application of Baltimore Gas & Electric Company for Adjustments to its Electric and Gas Base Rates*, Order No. 85374, at 77 (Feb. 22, 2013)).
[53] Delmarva notes that the Federal Reserve increased its short-term interest rates on December 14, 2016.

"authorized ROEs for distribution-only electric utilities (like Delmarva) have been about 20 basis points below those for integrated electric utilities."[54]

We find that Delmarva's reliance on our comparative risk observations in BGE's rate cases is misguided. Our comments in Case No. 9299[55] and again in Case No. 9406[56] were intended to distinguish between BGE's electric and gas distribution operations because "combining BGE's separate operations to produce a single return for the Company would lead to cross subsidization of services."[57] Unlike BGE, however, Delmarva has no gas distribution operations. Likewise, Delmarva's assertion that we must treat it the same as BGE in this instance is equally untenable. Delmarva has not pointed us to, nor are we aware of, any rule, regulation or precedent that would require us to grant the Company the same ROE as another electric utility or one higher than any gas utility in Maryland.

We turn now to consider the salient question of whether the authorized ROE of 9.48% should be affirmed. The Chief Judge thoroughly reviewed and discussed the parties' respective ROE methodologies. Their respective ROEs and ROE ranges can be summarized in the following table:

[54] OPC Appeal at 17 (citing OPC Ex. 18 (Woolridge Direct) at 8).
[55] Case No. 9299, Order No. 85374.
[56] Case No. 9406, Order No. 87591.
[57] Order No. 85374 at 77.

Method	Delmarva	Staff	OPC
DCF (Constant Growth)	8.89% to 9.72%	9.36%	8.40% to 8.70%
DCF (Multi-Stage)	9.40% to 10.99%	n/a	n/a
CAPM	9.14% to 12.99%	9.61%	7.90% to 8.0%
ECAPM	10.16% to 13.65%	n/a	n/a
Risk Premium	10.04% to 10.47%	n/a	n/a
Flotation Adjustment	12 bp	n/a	n/a
ROE Recommendation	10.60%	9.48%	8.60%

The Chief Judge also considered among other things the Company's risk profile, the capital market environment, the equity returns authorized by other jurisdictions, and the fact that Delmarva will not issue its own stock. Despite the Chief Judge's thoughtful considerations, it is concerning to us that the adopted ROE represents a 33-basis point reduction in the Company's current ROE. We have historically followed principles of gradualism when implementing major rate design changes, noting more recently that implementing gradual movement in lowering a utility's ROE could be appropriate "to lessen the impact on the company and investors."[58] As to Delmarva, we do not fault the Chief Judge's reasoning and decision to reject Delmarva's requested ROE in favor of a lower ROE. However, we find that gradualism warrants a lesser reduction in Delmarva's ROE. Consequently, we find that an ROE of 9.60% is both adequate and appropriate for Delmarva, considering the risks associated with its electric distribution

[58] *See* Order 87884 at 101.

operations in Maryland, the capital market conditions at the time of this proceeding, and the fact that Delmarva does not issue its own stock.

On appeal, Delmarva does not oppose removing the six-basis point flotation adjustment previously awarded to the Company in Case No. 9285, as it would be consistent with our ROE award to Pepco in Case No. 9418.[59] In the Proposed Order, the Chief Judge denied Delmarva's request for flotation costs because Delmarva does not issue its own stock and is now a component of Exelon. We agree and further find that the previous flotation adjustment of six basis points awarded to Delmarva is no longer appropriate. This does not end our discussion, however.

The Chief Judge also reasoned that an ROE around 9.5% would be consistent with the approved equity returns in other jurisdictions as well as the Commission's authorized ROE of 9.55% for Pepco. In its Reply Memorandum, Staff indicated that the national averages for authorized ROEs were 9.6% in 2015, 9.52% during the first six months of 2016, and 9.64% for the first nine months of 2016.[60] An ROE of 9.60% therefore matches the average authorized ROE in 2015 and is within four basis points of the average ROE for two-thirds of 2016.

We previously held in Case No. 9418 that current market conditions favored a cost of equity lower than 9.62%. Here, the Chief Judge reached similar conclusions in rejecting the Company's requested ROE. She gave little weight to Delmarva Witness

[59] *See id*. at 100. In Case No. 9418, we also considered the risks associated with Pepco's electric distribution operations in Maryland and the then-current market environment.

[60] Staff Reply Mem. at 10. In response to Delmarva's comparative risk argument, Staff explains that "a higher ROE for electric utilities as compared to gas utilities is often justified, in part, due to the higher risks faced by electric utilities that own and operate power plants (referred to here as integrated utilities); these integrated utilities are in States where the utilities have not been required to divest their power plants." *Id*. at 11.

Hevert's predictions of an upward trend in interest rates.[61] We are similarly unpersuaded by Delmarva's argument that the Chief Judge should have considered the recent change in Federal Reserve rates. The noted interest rate change occurred after the close of the evidentiary record in this case. Moreover, as the Chief Judge concluded, the increase in the Federal Reserve rate "is small and not enough to justify the increase in Delmarva's ROE proposed by [the Company]."[62] Given the above-stated ROE trends and record evidence supporting the Chief Judge's conclusions regarding Delmarva's risk profile and financial strength, we believe the market can sustain an ROE of 9.60%. It is unlikely that the ROE we authorize for Delmarva will deter investors of Exelon or hurt the Company's access to credit.

We also find that an ROE of 9.60% falls within Delmarva's Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") ranges and, in particular, toward the upper end of the Company's constant growth DCF range. Although Staff witness VanderHeyden did not provide separate ROE ranges for his DCF and CAPM calculations, his DCF and CAPM ROE calculations effectively represent the upper and lower boundaries for his recommended ROE, which is an average of his two calculations. An ROE of 9.60% also falls within these boundaries, albeit closer to Mr. VanderHeyden's CAPM calculation.[63]

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[61] Proposed Order at 152-53.
[62] *Id*. at 153.
[63] This should not be interpreted as any preference by this Commission for the CAPM method of calculating the cost of capital. Indeed, we have repeatedly stated that we are unwilling to rule that there can be only one correct method for calculating an ROE. *See, e.g.*, Order No. 87884 at 97.

Finally, this ROE further complies with the standards for *Bluefield*[64] and *Hope*[65]. It is comparable to the returns investors can expect to earn on investments of similar risk in the current market. It is sufficient to assure confidence in Delmarva's financial integrity and enable the Company to receive a fair return commensurate with its risk. It is further adequate to sustain Delmarva's credit so that the Company can continue to attract needed capital at reasonable rates and provide safe and reliable service to customers.

G. Rate Design and Customer Charge

In its application, Delmarva proposed that the fixed customer charge for the residential class be increased to $12.00 per month, with the remaining revenue requirement for residential service to be recovered through seasonal volumetric rates. For each of the non-residential classes, Delmarva proposed that the increase in the revenue requirement be apportioned to gradually shift the recovery of distribution costs from the volumetric rate component to the customer and demand charge components.[66] In contrast, Staff did not support an increase to the residential customer charge and recommended that the fixed charges for the other schedules not go beyond the percentage increase in the new revenue requirement.[67] Nevertheless, because the Chief Judge found that the Base Cost of Service Study ("COSS") submitted by Delmarva inappropriately allocates AMI meter costs as customer-related, she rejected the Base COSS for use in the

[64] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923).
[65] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[66] DPL Ex. 22 (Santacecilia Direct) at 11.
[67] Staff Ex. 28 (Blaise Direct) at 18.

rate design and accepted in its place OPC's method of allocating the revenue requirement.[68] OPC's methodology resulted in an increased customer charge for the residential class of $9.49 per month.[69] Although the Chief Judge acknowledged that the Commission generally prefers increasing the volumetric rates of residential customers rather than the fixed customer charge, she determined that a customer charge of $9.49 per month was not unreasonable.[70]

We find that the Chief Judge's proposed increase in the residential customer charge is excessive. Augmenting the customer charge from the current $7.94 to the proposed $9.49 represents a significant percentage increase of nearly 20% and could interfere with important Commission policy goals that have been consistently emphasized in Commission decisions. See, for example, Order No. 86994 (reversing the decision of the Public Utility Law Judge to raise Choptank's residential customer charge from $10 to $17 per month, finding that an increase of $1.25 per month was "more consistent with the principle of gradualism").[71]

In Pepco's most recent rate case, we rejected the company's proposal to elevate its customer charge from $7.39 to $12.00. We found instead that the charge should be set at $7.60, representing a modest 2.84% increase.[72] In that case, we stated that determining the appropriate customer charge is not an exact science, but rather requires the balancing

[68] Proposed Order at 173.
[69] *Id*. at 182.
[70] *Id*.
[71] Case No. 9368, *In the Matter of the Application of Choptank Electric Cooperative Inc. for Authority to Revise its Rates and Charges for Electric Service*, Order No 86994, at 7 (May 21, 2015).
[72] Order No. 87884 at 110-11.

of several important considerations. For example, the Commission places emphasis on Maryland's public policy goals that encourage energy conservation and efficiency. We also found that maintaining relatively low customer charges "provides customers with greater control over their electric bills by increasing the value of volumetric charges."[73] In contrast to volumetric rates, no matter how hard customers attempt to conserve energy or respond to the incentives created by newly installed AMI meters, they cannot reduce fixed customer charges.[74] Additionally, we expressed concern with how fixed charges would impact low income customers. Finally, we observed that low customer charges provide value to net metering customers, because utility tariffs allow customers to net the energy produced by their qualifying energy systems against the volumetric portion of their bills, but not their fixed monthly customer charges.[75]

In order to preserve these important public policy objectives, and to be consistent with the customer charges approved in other proceedings,[76] we authorize Delmarva to increase its residential customer charge to $8.17. That figure represents a 2.84% increase from the Company's existing charge of $7.94—the same percentage increase we allowed in the Pepco rate case.[77] The rest of the revenue requirement allocated to the residential customer class will be collected through the residential class' volumetric rates. Similarly, with respect to the non-residential customer classes, we direct that the fixed charges

[73] *Id*. at 110.
[74] During the public hearings in this matter, customers expressed concern that they could not act to decrease the fixed cost portion of their bills. *See* Oct. 25, 2016 Public Hr'g Tr. at 26 ("captive customers … can't avoid the increases in the standing delivery distribution charges….") and Oct. 27, 2016 Public Hr'g Tr. at 20, 26 (noting that customers consider a variety of measures to decrease energy bills, including purchasing efficient appliances, insulating their homes, and decreasing the use of lights).
[75] Order No. 87884 at 111.
[76] The currently authorized residential customer charges in Maryland are the following: BGE: $7.90; Choptank: $11.25; Pepco $7.60; Potomac Edison: $5.00; and SMECO: $9.50.
[77] Case No. 9418, Order No. 87884 at 111.

(customer and demand charges) *each* increase by 2.84%, with the rest of the revenue requirement attributable to each class to be collected through each class' respective volumetric rates.

III. <u>Conclusion</u>

After considering the evidence in the record, we find that the Proposed Order should be affirmed in part and reversed in part. For the reasons stated herein, the Proposed Order is modified accordingly, consistent with this Order.

IT IS THEREFORE, this 15th day of February, in the year Two Thousand and Seventeen, by the Public Service Commission of Maryland,

ORDERED: (1) That the Proposed Order of the Chief Public Utility Law Judge, issued on January 4, 2017, is affirmed in part and reversed in part, and modified accordingly consistent with the findings of this Order;

(2) That Delmarva Power and Light Company's ("Delmarva") Appeal of the Proposed Order is hereby granted in part and denied in part, consistent with the reasons stated herein;

(3) That the Office of People's Counsel's ("OPC") Appeal of the Proposed Order is hereby granted in part and denied in part, consistent with the reasons stated herein;

(4) That Delmarva is hereby directed to file tariffs for the distribution of electric energy in Maryland, which shall increase rates by not more than $38,267,710, for service rendered on or after February 15, 2017, subject to acceptance by the Commission,

consistent with the findings of the Proposed Order, as modified herein; and

(5) That all motions not granted herein are denied.

/s/ W. Kevin Hughes

/s/ Harold D. Williams

/s/ Jeannette M. Mills

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell
Commissioners

Attachment I

DELMARVA POWER & LIGHT COMPANY
CASE NO. 9424

Operating Income

Per Book Balance	$26,630,799
Uncontested Adjustments	461,551
Uncontested Balance per Proposed Order	$27,092,350
Pro Forma Wage And FICA Expense	$ (603,388)
Amortized Rate Case Expenses	$ (41,947)
ProForma Uncollectibles Expenses	$ 542,344
Reflect New Depreciation Rates	$ (4,628,734)
Amortization of AMI Regulatory Asset	$ (3,674,077)
Amortization of Legacy Meters	$ (925,054)
Reflect Merger Synergies Net of CTA	$ 2,388,846
Remove 50% of Employee Act. Expenses	$ 109,320
Remove 100% of Serp Expenses	$ 585,250
RE-amortize Hurricane Irene Expenses	$ 447,248
RE-amortize COPCO Acquisition Expenses	$ 2,788,880
Amortization - Solution One Transition Expense	$ 767,283
Annualize Late Payment Revenues	$ 72,366
Interest Synchronization	$ 428,319
Net Operating Income	**$ 25,349,006**

Attachment II

DELMARVA POWER & LIGHT COMPANY
CASE NO. 9424

Revenue Requirement

Rate Base	$ 707,246,234
Rate of Return	6.74%
Required Income	$ 47,668,396
Adjusted Income	$ 25,349,006
Income Deficiency	$ 22,319,390
Conversion Factor	1.71455
Revenue Requirement	**$ 38,267,710**

Rate Base

Per Books Balances	$ 654,011,714
Uncontested Adjustments	
Uncontested Balance per Proposed Order	$ 690,940,503
New Depreciation Rates	$ (466,048)
Amortization of AMI Regulatory Asset	$ 11,337,086
Reflect Synergies and CTA	$ 2,467,651
Adj. COPCO Acquisition Amortization	$ 2,788,880
Amortization - Solution One Transition Expense	$ 863,194
Pro Forma Cash Working Capital Allowance	$ (685,032)
Adjusted Rate Base	**$ 707,246,234**

ORDER NO. 87591

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR ADJUSTMENTS TO ITS ELECTRIC AND GAS BASE RATES	* * * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9406

Before: W. Kevin Hughes, Chairman
Harold D. Williams, Commissioner
Anne E. Hoskins, Commissioner
Jeannette M. Mills, Commissioner
Michael T. Richard, Commissioner

Issued: June 3, 2016

APPEARANCES

Daniel P. Gahagan, Beverly A. Sikora, Damon L. Krieger and Daniel W. Hurson for Baltimore Gas & Electric Company

Margaret M. Witherup, David Beugelmans and Todd R. Chason of Gordon Feinblatt LLC for the Maryland Energy Group and W.R. Grace & Company

Matthew W. Nayden and Jason Foltin, with H. Russell Frisby, Jr., John McCaffrey and Matthew Smilowitz of Stinson Leonard Street, LLP, for the Mayor and City Council of Baltimore

Leslie Romine, Jennifer Grace and Janice Flynn for the Public Service Commission Staff

Paula M. Carmody, Theresa Czarski, William Fields, Jacob Ouslander, Joseph Cleaver, Gary L. Alexander and Joyce R. Lombardi for the Maryland Office of People's Counsel

Steven M. Talson and Sondra McLemore for Maryland Energy Administration

Matthew Dunne for U.S. Department of Defense and Federal Executive Agencies

Lisa Brennan for Montgomery County, Maryland

Table of Contents

I. INTRODUCTION AND EXECUTIVE SUMMARY[1]

Baltimore Gas and Electric Company ("BGE" or "the Company") filed with the Maryland Public Service Commission ("the Commission") a request to increase its rates for gas and electricity in the amount of $224.5 million.[2] This unusually large request included a base increase of $53.1 million which included an increase in the Company's authorized rate of return and cost recovery for the Company's ongoing reliability and public safety investments. The request also included six years of ongoing investment in Advanced Meter Infrastructure ("AMI") in the amount of $140.7 million which the Company now sought to begin recovering in base rates. Finally, the request included a proposed $30.7 million increase related to Baltimore City's decision to raise conduit fee lease rates, which BGE requested to recover through a separate bill rider. Any one of the items would constitute a substantial increase in rates.

Our obligation in this case under the Public Utilities Article is to determine "just and reasonable rates" for the service BGE renders its customers. Under Supreme Court case law, we are also obligated to ensure that the Company has the opportunity to earn a return on its investment that permits it to remain financially sound and able to maintain credit and attract capital.[3] This requires a delicate balancing of competing interests, and presents among the most challenging tasks to any Commission. We have thoroughly reviewed BGE's Application and carefully considered all of the evidence presented in

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[1] Commissioners Harold D. Williams and Anne E. Hoskins issued a Concurring Statement; Commissioners Harold D. Williams and Michael T. Richard Dissent in Part. See attached Statements.
[2] The requested rate increase was updated by BGE throughout the course of the proceeding and reflects actual results through February 2016. This includes a 115.6 million in its electric distribution revenue requirement, a $78.2 million increase in its gas distribution revenue requirement, and a $30.7 million increase associated with the increased costs related to Baltimore City's conduit lease and maintenance fee.
[3] *Bluefield Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

this case as well as the comments rendered at the five evening public hearings. Based on this comprehensive review, we authorize BGE to increase its electric rates by $41.762 million and its gas rates by $47.776 million, for a total of $89.538 million.

In August 2010, the Commission unanimously granted BGE's request to proceed with deployment of AMI, noting in particular "smart-grid technology's ability ultimately to lower energy bills, improve customer service and relieve peak-time pressure on the transmission and distribution infrastructure."[4] In its decision, the 2010 Commission denied the Company's request to recover some costs during the roll out of the new smart meters and instead directed the Company to defer recovery of all costs until it could prove it had delivered a cost-beneficial system. At that time, the Commission did not want ratepayers to bear the risk that AMI would not provide benefits in an amount that exceeded the cost of the system. The consequence of this decision over a five year period has been to defer rate base recovery of almost all meters and metering infrastructure. This deferral of AMI costs, coupled with a relatively short depreciation life (10 years) for smart meters that the Commission adopted, has resulted in a large outstanding investment of $345 million for which BGE now seeks recovery.[5] However well intentioned the Commission's decision was, we must now deal with the potential rate shock of allowing six years of investments to be included in base rates.

After careful review of the case before us, we find compelling evidence that BGE's AMI system is cost beneficial to its customers. We conservatively estimate that customers will receive $1.28 on a net present value basis for every $1 invested in the

[4] Order No. 83531 at 49.
[5] Butts Supplemental Direct at 3; $503 million in total AMI expenditures are offset by U.S. DOE grant, resulting in a net outstanding investment of $345 million through September 2015.

AMI system. While we authorize recovery of certain costs BGE incurred in deploying AMI, we have taken steps to lessen the potential impact on residential customers by authorizing BGE to amortize AMI cost recovery over 10 years rather than five. In addition, we have carefully reviewed the contested adjustments and prudency of the expenses BGE incurred in deploying AMI. As detailed herein, we have reduced by $47.8 million the $140.7 million BGE requested in connection with its AMI deployment.

We have similarly undertaken a thorough review of the case before us with respect to the requested rate increase attributable to Baltimore City's decision to increase the fees it charges users of the City-owned underground conduits, including BGE, from $0.9785 per linear foot to $3.33 per linear foot effective November 1, 2015. It did so in order to go from repairing the conduit system as problems arose – a reactive maintenance program – to a proactive maintenance program. If upheld and implemented, this would increase BGE's conduit fee by $30.7 million per year. Despite several months of discussions between the parties, the evidence before us reflects continuing uncertainties about the increased conduit fee. BGE sued the City regarding the increased conduit fee, raising questions about the City's commitment to spend conduit fee revenues only on actual costs of conduit maintenance, the appropriate true-up mechanism, and the scope and speed of the proposed proactive maintenance program. The parties reached agreement on some guiding principles and are attempting to settle the matter via mediation, but unresolved issues remain and the litigation is ongoing. The City is just now taking initial steps to implement its proactive maintenance program.

In this case BGE asks to recover $30.7 million per year of the conduit lease fee increase in the rate effective period, and also requests to recover $18.97 million of the increased lease fee for the period of November 2015 through June 2016 when the rates authorized in this case will go into effect. After careful consideration for the reasons set forth herein, we find that these requested post-test year adjustments are not known and measurable and we deny their recovery in this case.[6] We urge BGE and Baltimore City to reach a resolution that ensures that BGE customers will pay an appropriate conduit fee that accurately reflects the necessary costs of providing electric distribution services.

Based on the record in this case, we find that maintaining BGE's return on equity (ROE) of 9.75% for its electric operations and 9.65% for its gas distribution services allows for a fair and appropriate return. Consistent with recent cases, the ROEs we approve will continue to provide BGE with ample opportunity to obtain necessary capital at reasonable rates. In addition, we adopt BGE's original capital structure submitted with its application which includes a common equity ratio of 51.9%. Furthermore, we authorize recovery of post-test year reliability spending through the evidentiary hearings, as well as inclusion of infrastructure expenditures for BGE's Strategic Infrastructure Development and Enhancement ("STRIDE") program.

In summary, we authorize an increase in BGE's electric rates of $41.762 million and its gas rates by $47.776 million, for a total of $89.538 million. This will result in an increase to the average monthly bill of $2.67 for a residential electric customer and $4.86 for a residential gas customer.[7] This is significantly less than BGE's proposed increase of $7.05 per month (not including the conduit fee surcharge) for an electric customer and

[6] We continue to allow BGE to continue to recover in rates the approximately $10 million per year in conduit lease fees it has been paying.
[7] The average residential monthly bill increase is based on an electric customer using 925 kWh per month and a gas customer using 57 therms per month.

$8.01 per month for a gas customer.[8] We are cognizant, however, of the effect any rate increase will have on BGE's ratepayers. In particular, we acknowledge and remain deeply concerned about the burdens that increased rates place on limited-income customers. We have strived to limit the rate impact in this case while allowing the Company to invest in safety and reliability and continue to modernize its distribution systems for the benefit of its customers.

[8] BGE Initial Brief at 5.

II. BACKGROUND

On November 6, 2015, BGE filed an application for Adjustments in Electric and Gas Base Rates and Other Tariff Revisions ("Application"), pursuant to §§ 4-203 and 4-204 of the Public Utilities Article of the *Annotated, Code of Maryland* ("PUA"), for authority to increase its rates and charges for the retail distribution of electricity and natural gas in Maryland. BGE's last electric and gas rate increase requests were partially approved in December 2014.[9] In its Application, BGE used a 12-month test year ending November 30, 2015, with nine (9) months of actual data and three (3) months of projected data, and stated that its evidence supported a $135.2 million increase in its electric distribution revenue requirement and a $77.8 million increase in its gas distribution revenue requirement. Based upon updated actual data for the full test year filed on January 5, 2016, BGE revised its requested electric revenue requirement increase to $117.1million and its requested gas revenue requirement increase to $78.8million.[10] BGE further revised its requested revenue requirement to reflect actual results through February 2016 and the impact of the Exelon/PHI merger synergies net of costs to achieve incurred through February 2016, so that its requested electric revenue requirement is $115.6 million and its requested gas revenue requirement is $78.2 million.[11]

A number of parties filed written testimony in this proceeding. BGE sponsored the testimony of Mark D. Case, Vice President for Regulatory Policy and Strategy,

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[9] *Re Baltimore Gas and Electric Company, Case No. 9355, Proposed Order of the Public Utility Law Judge (December 4, 2014).*

[10] Staff filed a Comparison Chart of the Parties for BGE's Electric and Gas Operations ("Comparison Chart or Chart"), March 25, 2016.

[11] BGE Initial Brief at 5; BGE Exhibit 26.

testified on a general basis for the rate increase;[12] William B. Pino, Director of Energy Acquisition and Demand Response Market Operations, testified regarding Smart-Grid enabled programs that produce energy and peak demand reductions and result in customer savings;[13] Michael B. Butts, Director of AMI Business Transformation, testified regarding the history and current status of BGE's Smart Grid and detailed the operational benefits and costs of the program ;[14] David M. Vahos, Vice President, Chief Financial Officer and Treasurer, testified about the revenue requirements, the Company's proposed capital structure and overall cost of capital, and the increase in Baltimore City conduit fees;[15] John C. Frain, Director, Regulatory Strategy and Revenue Policy, testified about gas and electric rate designs;[16] and David E. Greenberg, Manager of Rate Administration, testified about the Calendar Year ("CY") 2014 Company Recommended Gas Actual Embedded Cost of Service Study and the CY 2014 Company Recommended Electric Actual Embedded Cost of Service Study.[17] An additional witness testified on behalf of BGE: Adrien M. McKenzie, Vice President of FINCAP, Inc., provided an independent assessment of the fair rate of return that BGE should be authorized to earn

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[12] BGE Ex. 28, Prepared Direct Testimony of Mark D. Case ("Case Direct"); BGE Ex. 29, Prepared Rebuttal Testimony of Mark D. Case ("Case Rebuttal").

[13] BGE Ex. 14, Prepared Direct Testimony of William B. Pino ("Pino Direct"); BGE Ex. 15, Prepared Rebuttal Testimony (Corrected version) of William B. Pino ("Pino Rebuttal"); BGE Ex. 16 Prepared Surrebuttal Testimony of William B. Pino ("Pino Surrebuttal").

[14] BGE Ex. 3, Prepared Direct Testimony of Michael B. Butts ("Butts Direct"); BGE Ex. 4, Prepared Supplemental Direct Testimony of Michael B. Butts ("Butts Supplemental Direct"); BGE Ex. 5, Prepared Rebuttal Testimony of Michael B. Butts ("Butts Rebuttal").

[15] BGE Ex.21 Prepared Direct Testimony of David M. Vahos ("Vahos Direct"); BGE Ex. 22, Prepared Supplemental Direct Testimony of David M. Vahos (Vahos Supp. Direct); BGE Ex. 23, Prepared Rebuttal Testimony of David M. Vahos ("Vahos Rebuttal"); BGE Ex. 24, David M. Vahos Updated exhibits for February 2016; BGE Ex. 25, Prepared Surrebuttal Testimony of David M. Vahos ("Vahos Surrebuttal").

[16] BGE Ex. 18, Prepared Direct Testimony of John C. Frain ("Frain Direct"); BGE Ex. 19, Prepared Supplemental Direct Testimony of John C. Frain ("Frain Supp. Direct"); BGE Ex. 20, Prepared Rebuttal Testimony of John C. Frain ("Frain Rebuttal").

[17] BGE Ex. 9, Prepared Direct Testimony of David E. Greenberg ("Greenberg t Direct"); BGE Ex. 10, Prepared Rebuttal Testimony of David E. Greenberg ("Greenberg Rebuttal").

on its investment in providing electric and gas delivery service customers and;[18] additionally, Dr. Ahmad Faruqui, a Principal with The Brattle Group, testified in support of BGE's request to recover costs for its Smart Grid deployment.[19]

The Office of People's Counsel ("OPC") presented the testimony of David J. Effron, an independent consultant specializing in utility regulation, who testified regarding the revenue requirements including rate base and pro forma operating income adjustments of BGE;[20] Jonathan F. Wallach, Vice President of Resource Insight, Inc., who testified regarding electric revenue increase to the residential class, electric cost of service study, proposal to increase customer charges for electric Schedule R customers and proposal to recover Baltimore's conduit fees;[21] Peter J. Lanzalotta, a Principal with Lanzalotta & Associates, LLC, who testified regarding BGE's reliability and storm restoration matters;[22] J. Randall Woolridge, Professor of Finance at Pennsylvania State University, who testified regarding the cost of capital for electric & gas distribution services and evaluate BGE's rate of return testimony;[23] Nancy Brockway, former Commissioner of New Hampshire Public Utilities Commission, who testified regarding

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[18] BGE Ex.6 Prepared Direct Testimony of Adrien M. McKenzie ("McKenzie Direct"); BGE Ex. 7, Prepared Rebuttal Testimony of Adrien M. McKenzie ("McKenzie Rebuttal"); BGE Ex. 8, Prepared Surrebuttal of Adrien M. McKenzie ("McKenzie Surrebuttal").

[19] BGE Ex. 17, Rebuttal Testimony of Dr. Ahmad Faruqui ("Faruqui Rebuttal").

[20] OPC Ex. 29, Direct Testimony of David J. Effron; OPC Ex. 30, Surrebuttal Testimony of David J. Effron ("Effron Surrebuttal").

[21] OPC Ex. 23, Public Version Direct Testimony of Jonathan F. Wallach OPC Ex. 23A and Confidential Version Direct Testimony of Jonathan F. Wallach (collectively "Wallach Direct"); OPC Ex. 24, Rebuttal Testimony of Jonathan F. Wallach ("Wallach Rebuttal"); OPC Ex. 25, Surrebuttal Testimony of Jonathan F. Wallach ("Wallach Surrebuttal").

[22] OPC Ex. 34, Public Version Direct Testimony of Peter J. Lanzalotta OPC Ex. 34A Confidential Version Direct Testimony of Peter J. Lanzalotta ("Lanzalotta Direct"); OPC Ex. 35, Public Version Surrebuttal Testimony of Peter J. Lanzalotta OPC Ex. 35A, Confidential Version Surrebuttal Testimony of Peter J. Lanzalotta ("Lanzalotta Surrebuttal").

[23] OPC Ex. 20, Direct Testimony of J. Randall Woolridge ("Woolridge Direct"); OPC Ex. 21, Rebuttal Testimony of J. Randall Woolridge ("Woolridge Rebuttal"); OPC Ex. 22, Surrebutal Testimony of J. Randall Woolridge ("Woolridge Surrebuttal").

AMI installation process, BGE's customer AMI Education Plan, cyber security and privacy protections, and policy considerations related to legacy meters;[24] Maximillan Chang, who is a Principal Associate at Synapse Energy Economics, testified regarding the benefit-to-cost analysis for Smart Grid development and deployment;[25] Additionally, Paul Chernick presented testimony on behalf of OPC. Mr. Chernick, President of Resource Insight, Inc., testified regarding the some of the benefits BGE asserts with its Smart Grid investment.[26]

The Maryland Energy Group ("MEG") presented the testimony of Richard A. Baudino, a consultant with J. Kennedy and Associates, who testified regarding class cost of service, revenue allocation, rate design and tariff issues, and BGE's proposed Rider 5.[27] MEG also presented the testimony of Yitzchak Raphaeli, Process Manager for American Sugar Refining, Inc., who testified regarding reasonable utility rates for industrial, institutional and other large energy uses.[28]

The Public Service Commission Technical Staff ("Staff") presented the testimony of Patricia M. Stinnette, Director of the Accounting Investigations Division, who testified regarding revenue requirements;[29] Yulia Poberesky, Public Utility Auditor, who also

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[24] OPC Ex. 38, Direct Testimony of Nancy Brockway ("Brockway Direct"); OPC Ex. 39, Surrebuttal Testimony of J. Nancy Brockway ("Brockway Surrebuttal").
[25] OPC Ex. 26, Direct Testimony of Maximillan Chang ("Chang Direct"); OPC Ex. 27, Rebuttal Testimony of Maximillan Chang ("Chang Rebuttal").
[26] OPC Ex. 31, Public Version Direct Testimony of Paul Chernick OPC Ex. 31A and Confidential Version Direct Testimony of Paul Chernick (collectively "Chernick Direct"); OPC Ex. 32, Rebuttal Testimony of Paul Chernick ("Chernick Rebuttal"); OPC Ex. 33, Public Version Surrebuttal Testimony of Paul Chernick, OPC Ex. 33A, Confidential Version Surrebuttal Testimony of Paul Chernick ("Chernick Surrebuttal").
[27] MEG Ex. 2, Direct Testimony and Exhibits of Richard A. Baudino ("Baudino Direct"); MEG Ex. 3, Rebuttal Testimony of Richard A. Baudino ("Baudino Rebuttal"); MEG Ex. 5, Surrebuttal Testimony of Richard A. Baudino ("Baudino Surrebuttal").
[28] MEG Ex. 1, Direct Testimony of Yitzchak Raphaeli ("Raphaeli Direct").
[29] Staff Ex. 27, Corrected Direct Testimony and Exhibits of Patricia M. Stinnette ("Stinnette Direct");; Staff Ex. 28, Surrebuttal Testimony and Exhibits of Patricia M. Stinnette ("Stinnette Surrebuttal").

testified regarding revenue requirements;[30] Dr. C. Shelley Norman, a Regulatory Economist in the Electricity Division, who testified about the cost of service for the electric operations of BGE;[31] Jason Cross, a Regulatory Economist in the Telecommunications, Gas and Water Division, who testified about the cost of service for the gas operations of BGE;[32]Amanda Best, Assistant Director of the Division of Energy Analysis and Planning, who testified about the cost of capital, cost of equity structure and rate of return for the gas operations of BGE;[33] Craig Taborsky, Assistant Chief Engineer, who testified regarding the engineering aspects of BGE's use of Baltimore City's conduit;[34] Loubens Blaise, a Regulatory Economist in the Electricity Division, who testified regarding the electric rate design and proposed tariff changes;[35] Tanu Jeffrey Pongsiri, a Regulatory Economist in the Electricity Division, who testified regarding the gas rate design and proposed tariff changes;[36] Philip VanderHayden, Director of the Electricity Division, who testified on an overall rate of return for determining BGE's electric distribution rates and offered critique of BGE cost of capital testimony;[37] Jennifer Ward, Regulatory Economist in the Electricity Division, who testified on an

[30]Staff Ex. 25, Corrected Direct Testimony and Exhibits of Yulia Poberesky ("Poberesky Direct"); Staff Ex. 26, Staff Ex. 26, Surrebuttal Testimony and Exhibits of Yulia Poberesky ("Poberesky Surrebuttal").

[31] Staff Ex. 34, Public Version Direct Testimony and Exhibits of Dr. C. Shelley Norman , Staff Ex. 34A Confidential Version Direct Testimony of Dr. C. Shelley Norman (collectively "Norman Direct"); Staff Ex. 35, Rebuttal Testimony and Exhibits of Dr. C. Shelley Norman ("Norman Rebuttal"); Staff Ex. 36 Surrebuttal Testimony of Dr. C. Shelley Norman ("Norman Surrebuttal")..

[32] Staff Ex. 22, Direct Testimony and Exhibits of Jason Cross ("Cross Direct"); Staff Ex. 23,Surrebuttal Testimony of Jason Cross ("Cross Surrebuttal").

[33] Staff Ex. 24, Direct Testimony of Amanda Best ("Best Direct").

[34] Staff Ex. 33, Public Version Direct Testimony and Exhibits of Craig Taborsky and Staff Ex. 33A Confidential Version Direct Testimony and Exhibits of Craig Taborsky ("Taborsky Direct").

[35] Staff Ex. 44, Direct Testimony and Exhibits of Loubens Blaise ("Blaise Direct"); Staff Ex. 45, Rebuttal Testimony and Exhibits of Loubens Blaise ("Blaise Rebuttal"); Staff Ex. 46, Surrebuttal Testimony and Exhibits of Loubens Blaise ("Blaise Surrebuttal").

[36] Staff Ex. 44, Direct Testimony and Exhibits of Tanu Jeffrey Pongsiri ("Pongsiri Direct"); Surrebuttal Testimony and Exhibits of Tanu Jeffrey Pongsiri ("Pongsiri Surrebuttal").

[37] Staff Ex. 47, Direct Testimony and Exhibits of Philip VanderHayden ("VanderHayden Direct"); Staff Ex. 48, Surrebuttal Testimony and Exhibits of Philip VanderHayden ("VanderHayden Surrebuttal");

appropriate cost of equity and an overall rate of return for determining BGE's gas distribution rates;[38] and Daniel Hurley, Director of the Commission's Energy Analysis and Planning Division, who testified regarding the costs, benefits and cost-effectiveness of BGE Smart Grid Initiative.[39]

The Department of Defense and all other Federal Executive Agencies ("DOD/FEA") presented the testimony of Dennis W. Goins, owner of Potomac Management Group, who testified regarding the recovery of Baltimore City conduit fees through Local Government Owned Conduit Charge and BGE's eligible conservation program costs;[40] and David Shpigler, an Executive Consultant at Excergy, who testified regarding certain rate base and operating income adjustments and the overall revenue requirement.[41]

The Mayor and City Council of Baltimore ("City") presented the testimony of William M. Johnson, Director of Baltimore City Department of Transportation, who testified in support of the City's position that BGE should be permitted to recover in rates the Baltimore City conduit lease fees;[42] Lindsay Wines, Deputy Director, Administration, Baltimore City Department of Transportation, who testified in support of the City's position that expenses BGE should be permitted to recover in rates for

[38] Staff Ex. 42, Direct Testimony and Exhibits of Jennifer Ward ("Ward Direct"); Staff Ex. 43, Surrebuttal Testimony and Exhibits of Jennifer Ward ("Ward Surrebuttal");

[39] Staff Ex. 37, Direct Testimony and Exhibits of Daniel Hurley ("Hurley Direct"); Staff Ex. 38, Rebuttal Testimony and Exhibits of Daniel Hurley ("Hurley Rebuttal"); Staff Ex. 39, Surrebuttal Testimony and Exhibits of Daniel Hurley ("Hurley Surrebuttal").

[40] DOD/FEA Ex. 3, Direct Testimony and Exhibits of Dennis W. Goins ("Goins Direct").

[41] DOD/FEA Ex. 1, Direct Testimony Errata and Exhibits of Daniel Shipigler ("Shipigler Direct"); DOD/FEA Ex.2, Surrebuttal Testimony Errata and Exhibits of Daniel Shipigler ("Shipigler Surrebuttal");

[42] City Ex. 2, Direct Testimony and Exhibits of William M. Johnson ("Johnson Direct"); City Ex. 3, Rebuttal Testimony of William M. Johnson ("Johnson Rebuttal").

Baltimore City conduit lease fees;[43] and Dale Kessinger, a Consulting Principal and co-founder of Clearspring Energy Advisors LLC, who testified regarding cost allocation issues related to the proposed recovery of conduit lease expenses.[44] Staff, OPC, MEG, DOD/FEA, and the City filed direct testimony on February 8, 2016. The Company filed supplemental direct testimony on January 5, 2016 updating the Company's direct testimony for actual data for the full test year. Parties filed rebuttal testimony on March 4, 2016 and surrebuttal testimony on March 18, 2016. The Commission conducted evidentiary hearings at its offices on March 29-31, April 1, 4-8, 11-12, and held evening public comment hearings throughout the Company's service territory in Anne Arundel County, Baltimore County, Howard County, Harford County and Baltimore City, and on March 3, 7, 9, 16, 17, respectively. Parties filed Initial Briefs on April 29 and Reply Briefs on May 13, 2016.

Prior to the start of the evidentiary hearings on March 25, 2016, the Staff filed, on behalf of the parties, a Summary of Positions on Revenue Requirements (hereinafter, the "Chart").[45] The Chart reflects BGE's final purported revenue deficiencies of $117,123,000 for electric distribution operations and $78,890,000 for gas distribution operations. Staff's final position reflects an electric revenue requirement deficiency of $86,280,000 and a gas revenue deficiency of $66,161,000, while OPC's final position reflects an electric revenue deficiency of $66,155,000 and a gas revenue deficiency of $62,978,000.

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[43] City Ex. 4, Direct Testimony and Exhibits of Lindsey M. Wines ("Wines Direct");
[44] City Ex. 5, Direct Testimony and Exhibits of Dale Kessinger ("Kessinger Direct"); City Ex. 6, Rebuttal Testimony of Dale Kessinger ("Kessinger Rebuttal").
[45] Staff filed a Comparison Chart of the Parties for BGE's Electric and Gas Operations ("Comparison Chart or Chart"), March 25, 2016.

The Commission has thoroughly reviewed all of the evidence presented, including the comments received at the five public hearings in reaching the decisions in this Order.

III. DISCUSSION AND FINDINGS

A. Smart Grid Initiative

1. ***Benefit-Cost Analysis***

When the Commission granted the Company's request to proceed with deployment of its advanced metering infrastructure (or smart grid initiative) in Case No. 9208, the Commission directed that the Company defer recovery of costs until the Company had delivered a cost-effective system.[46] According to the Company's application, the Company deferred incremental costs of approximately $160 million through November 2015 in a smart grid regulatory asset,[47] for which the Company is seeking to recover $140 million in rate relief in this proceeding.[48] The Company is proposing to amortize the smart grid regulatory asset over a five year period.

Party Positions

BGE

The Company submits that its smart grid System is cost-effective. After applying a grant from the U.S. Department of Energy, the net cost of the smart grid Initiative is $344 million.[49] Its benefits include smart grid enabled programs such as BGE Smart Energy Rewards ("SER") and BGE Smart Energy Manager ("SEM") that allow customers to manage their energy usage more efficiently.[50] BGE states that smart grid

[46] *Re Baltimore Gas and Electric Company, 101 MD PSC 401, 420 (2010).*
[47] Direct Testimony of Mark D. Case, November 6, 2015 ("Case Direct") at 21.
[48] Direct Testimony of David M. Vahos, November 6, 2016 ("Vahos Direct") at 5; Supplemental Direct Testimony of David M. Vahos, January 5, 2016 (Vahos Supplemental Direct") at 2.
[49] Case Direct at 24.
[50] Case Direct at 24.

has led to an enhanced customer experience and improved outage restoration, with future applications likely.[51]

BGE witness Butts testified that BGE's smart grid deployment began in April 2012 and ended in September 2015.[52] Mr. Butts further testified that BGE did not initially design its communication plan and deployment schedule to accommodate customers who desired to opt-out of a smart metering device installation, and that BGE assumed that it would be able to exercise all of its standard rights to terminate service in the event a customer did not grant access to an indoor or otherwise inaccessible meter for installation of a smart metering device.[53] Therefore, BGE estimates that the cost to install smart metering devices increased by approximately $16.6 million as a result of customers' ability to defer a smart metering installation or not respond to BGE's multiple attempts to schedule installation.[54] According to Mr. Butts, the original deployment schedule called for all smart metering devices to be installed in a contiguous fashion but because so many non-responsive customers required another field visit, BGE continued to experience cost impacts from the opt-out proceedings, even after the Commission Order allowed BGE to assess fees on a customer's bill or terminate service for failure to grant access to an indoor or otherwise inaccessible meter.[55]

As more fully explained by Company witnesses Butts and Pino, the Company's position is that smart grid benefits exceed costs by a ratio of 2.3 on a nominal basis.[56] In other words, BGE claims that for every $1.00 in costs, BGE customers will realize

[51] Case Direct at 26.
[52] Prepared Direct Testimony of Michael B. Butts, November 6, 2015 ("Butts Direct") at 21.
[53] Butts Direct at 24-25.
[54] Butts Direct at 25.
[55] Butts Direct at 25-26.
[56] Vahos Supplemental Direct at 4.

approximately $2.30 in benefits.[57] According to Company witness Vahos, Operating Income Adjustment 22 provides for an annual level of Smart Grid incremental operational savings, ongoing costs, and regulatory asset amortization based on Smart Grid deferrals through the end of the test period.[58] Mr. Vahos testified that Operating Income Adjustment 22 reflects the $17.5 million in operational savings customers will realize during the test year, and provides for additional operational savings of $5.2 million projected for the rate-effective period (June 2016 through May 2017), for a total of $22.7 million in operational savings reflected in the calculation of revenue requirement.[59] Operating Income Adjustment 23 reflects amortization of the projected amounts deferred in the smart grid regulatory asset from the end of the test year through May 2016, and Rate Base Adjustment 6 adjusts rate base to reflect the smart grid regulatory asset based on a thirteen-month average as of May 2016.[60] Mr. Vahos stated that upon Commission approval of these adjustments, BGE will cease deferring a return on its unrecovered regulatory asset, thereby saving customers money.[61] Mr. Vahos claims that if the Commission does not approve these adjustments in this proceeding, BGE would continue to record a return on the smart grid regulatory asset and seek recovery of the remaining unrecovered costs in a future proceeding.[62]

The Company maintains that a five year amortization period is consistent with other regulatory asset amortization periods approved by the Commission.[63]

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[57] Vahos Supplemental Direct at 4.
[58] Vahos Direct at 11.
[59] Vahos Supplemental Direct, Exhibits at 28.
[60] Vahos Direct at 11.
[61] Vahos Direct at 14.
[62] Vahos Direct at 14.
[63] Vahos Direct at 13.

OPC

OPC witness David J. Effron testified about the deferred smart grid costs. In conjunction with the recovery of the smart grid costs, the Company has included net smart grid plant in service and the smart grid regulatory asset in its test year rate base. The smart grid regulatory asset includes deferred operation and maintenance expenses, deferred depreciation expense, deferred property taxes, deferred return on smart grid plant, and carrying charges on the cumulative balance of the regulatory asset itself.[64] The smart grid regulatory asset, net of applicable ADIT, is included in the test year rate base.

Mr. Effron notes that BGE did not offset smart grid operational savings against its calculation of the deferred operation and maintenance expenses included in the smart grid regulatory asset.[65] Instead, the benefits of smart grid operational savings have been reflected in the Company's test year cost of service in prior rate cases. Mr. Effron states, however, that the savings credited to ratepayers based on test year costs have lagged the Company's actual realization of smart grid operational savings.[66] He opined that the excess of the operational savings achieved over the amount credited to ratepayers should be offset by the deferred smart grid costs included in the recoverable smart grid regulatory asset.[67] He estimated that reducing the smart grid operational savings as recommended by Mr. Lanzalotta would reduce the overall electrical operational savings by 6.7%. With that modification, reflecting smart grid operational savings over and above the savings already reflected in rates reduces the smart grid regulatory asset by

[64] Direct Testimony of David J. Effron, February 8, 2016 ("Effron Direct") at 7.
[65] Effron Direct at 7.
[66] Effron Direct at 8.
[67] Effron Direct at 9.

$16,170,000, which would result in a reduction in the Company's electric rate base, net of accumulated deferred income taxes, of $9,643,000.[68]

Mr. Effron opined that the five year amortization period proposed by the Company imposes an unreasonable short term burden on customers and does not properly match the costs and benefits of the smart grid initiative.[69] He recommended a 10 year amortization period as reasonable and as achieving a better matching of smart grid costs and benefits.[70] This would result in a reduction of $21,486,000 to the Company's electric amortization and $8,778,000 to the Company's gas amortization.[71] Mr. Effron noted that the Company included smart grid rate year savings as a credit to the smart grid revenue requirement, which he adjusted based on Mr. Lanzalotta's recommendation to reduce the savings attributable to reductions to storm restoration costs, thereby increasing smart grid electric expenses by $1,042,000.[72]

In surrebuttal, OPC witness Effron responded to the citing by Company witnesses of language from page 38 of Order No. 85381 that "[t]he only direct savings that customers forego during the deployment years if we do not approve a tracker are the $15 million in reduced meter reading costs that BGE would pass through." Mr. Effron notes that the Company witnesses infer from this language that it was the Commission's intent that customers would permanently forego $15 million in reduced meter reading costs related to the smart grid program as compared to the tracker method.[73] Instead, Mr. Effron believes that the Commission's reference to the $15 million in reduced meter

[68] Effron Direct at 10-11.
[69] Effron Direct at 23.
[70] Effron Direct at 23-24.
[71] Effron Direct at 24.
[72] Effron Direct at 25.
[73] Surrebuttal Testimony of David J. Effron, March 21, 2016 ("Effron Surrebuttal") at 9.

reading costs foregone by customers "during the deployment years" reflects that it was the intent of the Commission only that the savings would be foregone over the time frame that the smart grid assets were being deployed, not permanently.[74] Mr. Effron points out that the very next sentence of the Order is "[w]hile having to wait to realize these savings is less than ideal, overall we believe the customer is better off for not having had to pay $160 million in surcharges in advance to achieve those savings."[75]

The testimony of OPC witness Nancy Brockway addresses: (a) customer care issues with the installation process; (b) the sufficiency of BGE's Education Plan; (c) whether AMI is providing customers with the superior electric customer experience promised by BGE; (d) the status of cyber security and privacy protections; and (e) policy considerations related to legacy meters.

Ms. Brockway discusses the issues of customer resistance to BGE's smart meter initiative, hard-to-access meters, and non-responsive customers, and the resulting opt-out orders.[76] Pointing to BGE's reported installation rates over the years of deployment, Ms. Brockway does not agree that the Commission's opt-out orders have had a substantial impact on BGE's smart grid deployment and its achievement of the installations per its 2010 business plan.[77] Ms. Brockway finds unsatisfactory BGE's explanation for its failure to complete meter installation, noting that BGE has often had difficulties reaching all of its customers when it is trying to contact them or gain access to their premises.[78] Ms. Brockway recommends that the Commission keep the reporting mechanism open

[74] Effron Surrebuttal at 10.
[75] Effron Surrebuttal at 10.
[76] Direct Testimony of Nancy Brockway, February 8, 2016 ("Brockway Direct) at 11-15.
[77] Brockway Direct at 14.
[78] Brockway Direct at 14.

until the hard-to-access issues reach zero percent, or at least as close to zero as can be obtained, and that BGE be required to continue reporting on opt-out numbers.[79]

Although Ms. Brockway agrees that BGE has fulfilled the literal terms of its communication and customer education plan ("Plan"), Ms. Brockway notes that the Plan did not prevent the customer resistance to the installation of the meters.[80] Ms. Brockway opines that the Plan is too limited and does not provide customers a usable understanding of customer awareness of and engagement with the data made available through communicating interval meters.[81]

Ms. Brockway believes that all of the new functionalities of smart meters have not been realized. She testified about cyber security risks and privacy issues. She recommends that additional functionalities such as the ability to remotely control lights, refrigerators, thermostats, door locks, water usage, washing machines, and robot vacuums be delayed until there is a greater understanding of the extent to which risks can be eliminated or at least greatly reduced, and until the general public has expressed an interest in these new functions.[82]

Lastly, Ms. Brockway concurred with the conclusion of OPC witness Maximilian Chang that the $48 million in unrecovered capital assets associated with retired legacy meters should be disallowed.[83] Alternatively, Ms. Brockway recommends that the costs of the BGE smart grid initiative be allocated equitably between stockholders and

[79] Brockway Direct at 15.
[80] Brockway Direct at 17.
[81] Brockway Direct at 17.
[82] Brockway Direct at 32.
[83] Brockway Direct at 33.

customers, which she opined would be consistent with Commission Order No. 83531.[84] Ms. Brockway stated that to permit BGE to recover a full return "on" and "of" its legacy meters and its AMI meters would allow two sets of meters in rate base, one of which is no longer used and useful, creating a double recovery of metering costs.[85] She noted that at least two other commissions, California and Kansas, have denied 100% return of and on legacy meters.

On surrebuttal OPC witness Brockway maintains that there has been customer resistance to installation of smart meters. Ms. Brockway opines that BGE should have anticipated that customers would want an "opt-out," as well as the difficulties in gaining access to customer premises.[86] Ms. Brockway testified that almost immediately from the time that deployment of smart meters began, there were consumer demands for opt-out, and utilities in other jurisdictions were getting demands from customers for the ability to opt-out.[87] Ms. Brockway also maintains that BGE should be directed to continue collecting and reporting metric information regarding the smart grid system.[88]

Ms. Brockway believes the filing of the present rate case operates to supersede the settlement agreement reaching in Case No. 9355, and thus the fact that the settlement agreement identified a 10-year amortization period for legacy meter accounting does not bind OPC to agree to the Company's cost recovery proposal in this case.[89]

[84] Brockway Direct at 33.
[85] Brockway Direct at 34.
[86] Surrebuttal Testimony of Nancy Brockway, March 21, 2016 ("Brockway Surrebuttal") at 4-5.
[87] Brockway Surrebuttal at 4.
[88] Brockway Surrebuttal at 5-6.
[89] Brockway Surrebuttal at 7.

With regard to recovery of abandoned legacy meters, Ms. Brockway testified that not all plant assets are accorded 100% recovery *of* and *on* their undepreciated balances.[90] She opined that because BGE retired an entire class of operable meters at one time, of its own volition, for a program whose benefits are as of yet unproven, puts these costs in a different category from run-of-the-mill plant assets such as wooden poles.[91]

OPC witness Peter J. Lanzalotta reviewed portions of the Company's testimony related to planning, reliability and storm restoration matters. Mr. Lanzalotta concluded that electric service reliability has improved greatly over recent years due to factors other than AMI, including changes in reliability-related regulations in RM-43, and a big increase in reliability-related spending over the period 2013-2015.[92] Mr. Lanzalotta compared the average annual customer interruptions for the period of 2008 through 2012 with the annual average customer interruptions for 2013-2014 (both with no exclusions for major outage events)[93] and determined that annual customer interruptions have decreased by more than 40%.[94] Mr. Lanzalotta opined that with more than a 40% reduction in customer interruptions, the need for truck rolls is reduced and outage duration is reduced because there are more than 40% fewer customers to restore to service.[95] Therefore, he concluded that the savings attributed to avoided truck rolls and

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[90] Brockway Surrebuttal at 9.
[91] Brockway Surrebuttal at 9.
[92] Direct Testimony of Peter J. Lanzalotta, February 8, 2016 ("Lanzalotta Direct") at 5.
[93] "Major outage event" means an event during which:
(a) Both:
(i) More than 10 percent or 100,000, whichever is less, of the electric utility's Maryland customers experience a sustained interruption of electric service; and
(ii) Restoration of electric service to any of these customers takes more than 24 hours; or
(b) The federal, State, or local government declares an official state of emergency in the utility's service territory and the emergency involves interruption of electric service. COMAR 20.50.01.03.
[94] Lanzalotta Direct at 13-14.
[95] Lanzalotta Direct at 14.

to reduced storm restoration duration should be reduced by at least 40%.[96] Lastly, Mr. Lanzalotta discussed the likelihood of avoided transmission costs due to AMI.

On surrebuttal, OPC witness Lanzalotta responded to BGE witness Butts' criticism of his recommended 40% reduction in storm-related savings due to reduced truck rolls. Mr. Lanzalotta opined that the Company's increased reliability is reducing the number of customer interruptions resulting from weather conditions, and that what used to be major events may not always rise to those levels of customer interruptions in the future.[97] Mr. Lanzalotta stated that the benefits attributable to avoided truck rolls and the resultant reduced outage duration are substantially undercut by the reductions in the number of customer interruptions being experienced as a result of the increasing reliability of the Company's distribution system.[98]

OPC witness Maximilian Chang opined that the Company's benefit-cost analysis of the smart grid initiative was flawed. Mr. Chang believes that the Company overstated both market-side and operational benefits attributable to the smart grid program. Mr. Chang does not believe Smart Energy Manager (SEM) benefits should be included in the benefit-to-cost analysis because the savings could have been achieved without the smart grid investments.[99] Mr. Chang believes that the smart grid-enabled tools available through the SEM platform have not materially impacted energy savings.[100] Mr. Chang

[96] Lanzalotta Direct at 14.
[97] Surrebuttal Testimony of Peter J. Lanzalotta, March 21, 2016 ("Lanzalotta Rebuttal") at 5.
[98] Lanzalotta Surrebuttal at 4.
[99] Direct Testimony of Maximilian Chang, February 8, 2016 ("Chang Direct") at 9-10.
[100] Chang Direct at 13.

also believes that the Company has overstated demand and energy savings attributable to the Smart Energy Rewards (SER) program due to free-ridership issues.[101]

Mr. Chang reviewed the costs of the smart grid initiative, including in his benefit-cost analysis legacy meter costs, which he believes to be consistent with the Commission's guidance in Order Nos. 83410 and 83531 in Case No. 9208.[102] Mr. Chang raised concerns about the costs associated with failed meters[103] and the Company's difficulty in completing installations.[104] Mr. Chang believes that the Company should have reasonably foreseen some difficulty with non-responsive customers given the Company's 30 percent incompletion rate for field jobs.[105]

Mr. Chang also raised concerns about the treatment of bill credits.[106] Mr. Chang stated that his organization has reconsidered its determination of the treatment of bill credits paid to participants of the SER program; where he used to consider the credits as intra-customer transfers, as the Company does, participants of the SER program experience real costs associated with thermal comfort and are being compensated for providing a service in the form of load reductions.[107]

When Mr. Chang used alternate inputs developed by OPC and included legacy meter costs, the benefit-cost ratio is below one (0.75).[108] Mr. Chang further noted that the Company's meter failure rate is twice as high as originally projected, though currently

[101] Chang Direct at 14-15.
[102] Chang Direct at 18.
[103] Chang Direct at 19-20.
[104] Chang Direct at 20-23.
[105] Chang Direct at 20-22.
[106] Chang Direct at 23-24.
[107] Chang Direct at 23-24.
[108] Chang Direct at 30.

the Company does not have to report meter failures in its quarterly reports.[109] Mr. Chang recommended that the Commission consider disallowing $193 million of the Company's costs, in order to break even.[110] He further recommended that the Commission require BGE to provide a revenue requirement impact assessment and regular analyses of the cost-effectiveness of the smart grid initiative going forward.[111]

On surrebuttal, Mr. Chang adjusted his benefits calculation somewhat. He made an adjustment of $21 million to the estimate of free ridership that both he and OPC witness Chernick made; an adjustment of $1 million for the emergency strike price as described in witness Chernick's surrebuttal testimony; and an adjustment of $1 million for calculations in Unforced Capacity as described in Mr. Chernick's surrebuttal testimony.[112] Mr. Chang also updated his estimate of SEM program costs based in part on corrected Company testimony.[113] Mr. Chang continues to recommend that the cost of legacy meters be included in the benefit-cost analysis, which he states is consistent with the Commission's inclinations in Order No. 83410.[114] Mr. Chang's updated analysis indicated that the Company's smart grid initiative remains not cost effective with a present value benefit-cost ratio of 0.82 (benefits of $609 million, costs of $745 million). Mr. Chang maintains that the Commission should disallow the $136 million difference between OPC's estimate of costs and benefits (hold harmless credit).

OPC witness Paul Chernick reviewed some of the benefits BGE asserted are provided by the Smart Energy Rewards (SER) and Smart Energy Manager (SEM)

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[109] Chang Direct at 30.
[110] Chang Direct at 30.
[111] Chang Direct at 30.
[112] Surrebuttal Testimony of Maximilian Chang, March 21, 2016 ("Chang Surrebuttal") at 3.
[113] Chang Surrebuttal at 6.
[114] Chang Surrebuttal at 7.

programs, as well as incremental savings from the pre-existing PeakRewards (PR) program. Mr. Chernick concluded that the benefits claimed by BGE are overstated due to over a dozen distinct errors.[115]

Mr. Chang addressed the estimation of load reductions. Mr. Chernick addressed the effect of the load reductions on the BGE zonal peak forecast and capacity obligation. Mr. Chernick testified that BGE's model does not reflect well the development of the PJM forecasts that drive capacity obligations, and that the SER load reductions are not likely to reduce peak forecasts.[116] Mr. Chernick noted that BGE's estimates of savings are based on the PJM 2015 Forecast of load growth, which averages about 6% higher than the current 2016 forecast.[117] In addition, Mr. Chernick believes BGE misestimated the load reductions due to the SER by ignoring the free riders in the program.[118] Mr. Chernick would estimate that the actual load effect of the SER is the change in total load from all eligible SER-only customers, excluding the PR customers, which would reduce BGE's estimates of the SER peak reductions by about 50% in 2014 and 30% in 2013 and 2015.[119] The resulting reduction in peak loads would reduce the present value of avoided capacity cost by about $30 million, demand-side price mitigation by about $20 million, and avoided T&D by about $50 million.[120]

Mr. Chernick opined that due to the structure of the PJM forecasting model, the effect of the SER and PR load reductions on BGE's capacity obligation is likely to be tiny, and the effect of SEM load reductions is likely to be substantially lower than BGE

[115] Direct Testimony of Paul Chernick, February 8, 2016 ("Chernick Direct") at 7.
[116] Chernick Direct at 10.
[117] Chernick Direct at 10.
[118] Chernick Direct at 10.
[119] Chernick Direct at 15.
[120] Chernick Direct at 15.

assumes.[121] Mr. Chernick claims that BGE's estimates of the reduction in the PJM forecasts due to the SER were about 50 to 70 times larger than the reduction actually produced by the PJM forecasting model.[122] Mr. Chernick also believes that BGE is overstating the reduction in capacity obligation from the SEM by a factor of 3.[123]

Mr. Chernick identified a total of five errors in BGE's analysis of capacity price mitigation: (1) the SEM will affect the PJM capacity requirement and the price of capacity much less than BGE assumes; (2) the load forecast that BGE uses to estimate the amount of capacity that Maryland customers will bear is much higher than PJM's current forecast; (3) BGE assumes that prices for Delmarva will always be affected by BGE loads in future Base Residual Auctions[124] ("BRAs"); (4) the coefficients that BGE uses to convert load reductions and cleared resources to price reductions is grossly overstated; and (5) the price reduction from adding the BGE program resources to the capacity auctions are often less than the reduction from adding generation or other premium resources.[125] Mr. Chernick offered corrected price-mitigation coefficients which would decrease BGE's claimed price-mitigation benefits by over $170 million.[126] He summarized that the SER and PR programs are unlikely to produce any meaningful capacity-price benefits; the SEM may produce some price benefits, but substantially less

[121] Chernick Direct at 20.
[122] Chernick Direct at 23.
[123] Chernick Direct at 24.
[124] The Base Residual Auction is conducted to allow for the procurement of resource commitments to satisfy the PJM region's unforced capacity obligation for the Delivery Year and allocates the cost of those commitments to Load Serving Entities (LSEs) through a Locational Reliability Charge. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/rpm-base-residual-auction-faqs.ashx.
[125] Chernick Direct at 26.
[126] Chernick Direct at 37.

than BGE assumes, since BGE overstated the sensitivity of the load forecast to recent load reductions and the response of price to reductions in forecast load.[127]

Mr. Chernick identified four problems common to BGE's estimates of transmission and distribution (T&D) benefits: (1) BGE's inability to identify any projects in the years in which BGE claims large avoided capital costs; (2) BGE's inability to produce any documents demonstrating that its T&D planners actually reflect the SER and PR load reductions claimed; (3) the mismatch between the timing of the SER and PR load reductions and the timing of the peak loads driving T&D investment; and (4) BGE's failure to annualize the avoided capital costs.[128]

Mr. Chernick identified eight problems in BGE's estimate of the value of avoided transmission: (1) BGE computes the $/kW avoided costs from the total cost of its 250 kV and 500 kV transmission system, priced as if it were all constructed in 2015; (2) BGE includes as import capability transmission facilities that are not associated with imports, but for delivery to customers (or export) of energy from generation in the BGE zone; (3) BGE does not divide the costs of these facilities by the load in the BGE zone, but by the zone's import capability; (4) reductions during the incentive hours on Energy Savings Days (ESDs) are unlikely to have affected transmission planning or costs; (5) BGE cannot identify the hours whose loads affected the allocation of costs of any transmission projects to the BGE zone; (6) BGE was unable to identify the type of load (by location or timing) for its past or projected transmission projects; (7) while BGE assumes that one megawatt of load reduction would reduce the required import capability by one megawatt, BGE does not know how PJM determines the required import capability; and

[127] Chernick Direct at 37.
[128] Chernick Direct at 38.

(8) BGE's import capability estimate of 6,527 MW is not taken from PJM's Regional Transmission Expansion Plan ("RTEP"), but from the Capacity Emergency Transmission Limit (CETL) reported in the 2018/19 BRA planning parameters.[129] Mr. Chernick stated that the improved methodology of dividing the escalated transmission cost by BGE's forecast peak, rather than the 2018/19 CETL, would reduce the $/MW value by 8% using the 2017/18 forecast and 11-14% using the forecasts for 2013-2015, when BGE claims $86 million in transmission investments were avoided.[130] With regard to distribution, Mr. Chernick identified evidence regarding the effect of reductions in peak substation loads due to the load reductions from SER and PR programs, concluding that it is unlikely that there have been or will be any avoided transmission or distribution investments from BGE's demand-response programs.[131]

Mr. Chernick notes that the most important factors in BGE's estimates of energy revenues are the annual number of non-emergency hours in which the programs would operate, the forecast of locational marginal price (LMP) in those hours, the annual number of emergencies in which the programs would operate, the number of hours per emergency during the program operation, and the assumed price in the emergency hours.[132] He found two problems with BGE's assumptions. His first observation was that BGE extrapolates the emergency price from a 2014 price for emergency energy in extreme winter conditions, including spiking gas prices.[133] His second was that BGE assumes that two of the four ESDs for the SER each year will be called on days that turn

[129] Chernick Direct at 42-46.
[130] Chernick Direct at 47.
[131] Chernick Direct at 47-49.
[132] Chernick Direct at 50.
[133] Chernick Direct at 50.

out to be emergency events, even though just one summer emergency event has occurred in the last three years and there is no assurance that BGE will know a day in advance that an emergency will be called by PJM.[134] If the number of emergency ESDs is corrected from 2 to 0.5 the SER and PR revenues are annually reduced by about $13 million, while introducing the summer emergency price to the last actual value reduces revenues another $1 million.[135]

Mr. Chernick stated that he identified three significant problems with BGE's analysis of avoided energy costs: (1) assuming that the avoided energy cost is equal to the standard-offer rate; (2) ignoring load shifting in the SER and PR programs; and (3) including in the SER savings customers who decrease their use due to random variation, but excluding any offset for the customers who increase their usage for the same reasons.[136] Mr. Chernick believes that the avoided energy cost should represent only the energy portion of the standard-offer price, which based on his estimate and calculation would reduce the avoided energy costs by 30%, or about $40 million.[137] He also believes that the energy avoided costs would be offset by load-shifting to hours outside the incentive period for SER, which would reduce the present value of the avoided energy costs by over $2 million and the energy price mitigation by $1 million.[138]

Mr. Chernick disagrees with BGE's treatment of ignoring the SER rebates for SER participants under the rationale these payments are not costs, noting that even half of

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[134] Chernick Direct at 51.
[135] Chernick Direct at 52.
[136] Chernick Direct at 52.
[137] Chernick Direct at 53-54.
[138] Chernick Direct at 54-55.

the incentive payment would have a present value of $48 million.[139]

Mr. Chernick identified problems in BGE's analysis of energy price mitigation based on errors discussed above. In his opinion, most importantly, BGE erred in assuming that the BGE zone is the only load that affects prices in the BGE, Pepco, Delmarva and AP zones.[140] He conducted his own analysis which would reduce the energy price mitigation by 79%, or $80 million.[141] Table 10 in Mr. Chernick's direct testimony summarizes the system benefits based on his recommended adjustments.

On surrebuttal, OPC witness Chernick addresses various technical issues and makes corrections to his direct testimony. Mr. Chernick notes that BGE witnesses were correct with regard to double-counting of free riders in his testimony and in OPC witness Chang's testimony.[142] Additionally, Mr. Chernick increased the present value of the SER capacity price mitigation by about $0.9 million, due to an error.[143] Lastly, Mr. Chernick accepted BGE witness Pino's adjustment based on the PJM emergency price.[144]

Witness Chernick disagrees with BGE witness Pino's rebuttal testimony. Mr. Chernick states that he did not replace the emergency price for energy during emergencies with the lower LMP as Mr. Pino claims.[145] Mr. Chernick states that he did not use PJM data relevant to the PJM Load Forecast in correcting BGE's estimate of the reduced load at T&D peaks, but rather he used actual data on the lack of coincidence of the SER and PR load reductions with the T&D peak hours.[146] Witness Chernick

[139] Chernick Direct at 56-59.
[140] Chernick Direct at 60.
[141] Chernick Direct at 65-66.
[142] Surrebuttal Testimony of Paul L. Chernick, March 21, 2016 ("Chernick Surrebuttal") at 2.
[143] Chernick Surrebuttal at 2-3.
[144] Chernick Surrebuttal at 3.
[145] Chernick Surrebuttal at 4.
[146] Chernick Surrebuttal at 4.

contends that BGE witness Pino double-counted the savings from load reductions in that saving energy does not avoid capacity charges in addition to the capacity charges avoided by peak reductions.[147]

Mr. Chernick testified that BGE made assertions in rebuttal that were unsupported.[148] With respect to the frequency of emergency pricing, Mr. Chernick notes that PJM called the short-lead-time load management resources only four times in the nine-year period studied, and contends that Mr. Pino's claim that the SER program would have been eligible for seven emergency events over the past ten year is misleading.[149] Mr. Chernick takes issue with Mr. Pino's apparently unsupported assertion that he understated the LMP during future non-emergency ESD hours.[150]

Mr. Chernick notes that BGE witnesses did not respond to his direct testimony that the peak time rebates pay customers to suffer discomfort and inconvenience and are therefore costs in a cost-effective analysis.[151] He states that the peak-time rebate in the SER differs from the rebates paid by utilities in energy-efficiency programs in that rebates in energy efficiency programs are designed to offset part of the cash cost of measures, while the peak-time rebates pay the customer for unknown cash costs and unquantified discomfort.[152]

Mr. Chernick takes issue with BGE witness Pino's treatment of increases in load before and after the SER incentive hours.[153] He also takes issue with BGE witness Faruqui's claim that free ridership within the participant group is offset by those

[147] Chernick Surrebuttal at 5-6.
[148] Chernick Surrebuttal at 10.
[149] Chernick Surrebuttal at 11.
[150] Chernick Surrebuttal at 12.
[151] Chernick Surrebuttal at 14.
[152] Chernick Surrebuttal at 15.
[153] Chernick Surrebuttal at 17-23.

customers in the participant group that actually increased load during ESDs.[154] Mr. Chernick contends that BGE's definition of "participant" for the SER program is someone whose usage is lower in the ESD than in the comparison days, while in most energy-efficiency and load-management programs, customers opt in and become participants.[155] He concludes that the BGE rebuttal does not offer any reason to believe that the free-rider effect is any less than his initial estimate of 30%.[156]

Mr. Chernick contends that this proceeding is not bound by the Commission's preapproval of energy-efficiency programs in Case No. 9154 and involves a very different type of load reduction (for the SER) than the energy-efficiency load reductions.[157]

In his surrebuttal testimony, OPC witness Lanzalotta explained his recommended 40% reduction in storm-related savings due to reduced truck rolls and performed his calculation using 2015 data. Mr. Lanzalotta calculated that the annual number of customer interruptions (CI) in the years 2013-2015 was 48.32% less than the average customer interruptions (CI) in the period 2008-2012.[158]

Department of Defense

David Shpigler testified on behalf of the U.S. Department of Defense and all other federal executive agencies ("DOD"). DOD witness Shpigler noted that the aim of a smart grid system is to reduce operating expenses through the use of advanced

[154] Chernick Surrebuttal at 24.
[155] Chernick Surrebuttal at 24-25.
[156] Chernick Surrebuttal at 29.
[157] Chernick Surrebuttal at 36-37.
[158] Surrebuttal Testimony of Peter J. Lanzalotta, March 21, 2016 at 3.

automation equipment.[159] Thus, he found it inconceivable that the efficiency gains that BGE claims to support through use of its smart grid system would result in even higher O&M expenses.[160] Mr. Shpigler recommended that the Commission disallow BGE's proposed inclusion of the incremental O&M expense in revenue requirements. With respect to BGE's proposed amortization of its smart grid regulatory asset, Mr. Shpigler opined that a 10-year amortization is more appropriate and provides for a matching between the smart grid asset recovery and the associated regulatory asset recovery.[161] He stated that the service life of the smart grid assets are likely to provide service for a minimum of 10 years, and likely significantly longer than that.[162] He further noted that the majority of utilities across the country have approved amortization periods longer than BGE's proposed 5 years, and provided the examples of Pacific Gas & Electric (20 years), Commonwealth Edison (10 years), and Texas-New Mexico Power (7 years).[163] He testified that smart grid technology often features a service life in the range of 10 to 15 years.[164] Mr. Shpigler also recommended an adjustment based on increased availability of working capital that he believes will be realized from the deployment of smart meters.[165] Lastly, Mr. Shpigler recommended an adjustment to the conversion factor that is applied to revenue requirement in order to "gross-up" for expected taxes and uncollectible customer accounts.[166] Mr. Shpigler proposed that BGE's proposed gross-up conversion factor be adjusted to reflect BGE's uncollectible experience over the past

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[159] Direct Testimony of David Shpigler, February 8, 2016 ("Shpigler Direct") at 6.
[160] Shpigler Direct at 6.
[161] Shpigler Direct at 8.
[162] Shpigler Direct at 8.
[163] Shpigler Direct at 9.
[164] Shpigler Direct at 9.
[165] Shpigler Direct at 11 *et seq.*
[166] Shpigler Direct at 14 *et seq.*

three years, and be adjusted to account for a reduction in the amount of unpaid electric and gas bills, or uncollectible accounts.[167] Mr. Shpigler stated that industry experience has demonstrated that reductions in uncollectible accounts associated with deployment of automated disconnect and related devices are typically in excess of 50%, though he cited no authority in his testimony.[168]

On surrebuttal, DOD witness Shpigler stated that because rates are set for the rate year, cost recovery should take into account the reasonableness of requested O&M costs, not based on some future period, but specifically for the rate year.[169]

Staff

Daniel J. Hurley prepared Staff's analysis of the costs, benefits, and cost-effectiveness of the Company's smart grid initiative. Mr. Hurley concluded that the cost estimates used by the Company are reasonable.[170] Staff divided the benefits into core benefits - benefits that were included in the original business case and which have an approved reporting metric developed through the work group process or have been accepted in the EmPOWER Maryland cases cost-benefit analysis, and additional benefits – benefits that were developed outside of the work group process and do not have an approved reporting metric.[171] Based on Staff's analysis of the costs and core benefits, Staff calculated a benefit-cost ratio of 1.37, indicating that the AMI project is cost-effective using the core benefits alone.[172]

[167] Shpigler Direct at 15.
[168] Shpigler Direct at 17.
[169] Surrebuttal Testimony of David Shpigler, March 21, 2016 (Shpigler Surrebuttal") at 7.
[170] Direct Testimony and Exhibits of Daniel J. Hurley, February 8, 2016 ("Hurley Direct") at 2.
[171] Hurley Direct at 2.
[172] Hurley Direct at 2.

Staff generally supports the Company's calculation of Operations Benefits, comprised of Operations and Maintenance ("O&M") Savings and Avoided Capital Costs, however Staff disagrees with the 3% inflation rate used by the Company; Staff instead used a 2.3% inflation rate based on a 15-year average from 2001-2015, the same rate that is used for increasing future costs in the EmPOWER Maryland cost effectiveness analysis.[173] Staff did not recommend any change to the Company's calculation of avoided Transmission and Distribution ("T&D") costs noting that the Company has consistently applied the cost savings for transmission and distribution in the cost effectiveness analysis for the PeakRewards program implementation in 2008 through the cost effectiveness analysis for the EmPOWER Maryland programs.[174]

Staff reviewed the Supply Side Benefits as well. With regard to Capacity Price Mitigation, Staff noted that the Company followed the methodology approved by the Commission in Order No. 87082. Staff has no major concerns with the calculation.[175] Staff also reviewed and finds reasonable the Company's assumptions with respect to the calculation of energy revenue.[176] Staff also finds the assumptions used to determine the energy price mitigation reasonable but cautions that any drop in the estimate energy savings for SER and SEM will result in a lower energy price mitigation value.[177]

Staff does not necessarily agree with the Company's assumption of energy use and demand reduction of 1.5%. If the energy reduction held constant at 0.99%, the net present value of the energy conservation benefit would drop from $137 million to $100

[173] Hurley Direct at 13.
[174] Hurley Direct at 13-14.
[175] Hurley Direct at 16.
[176] Hurley Direct at 17.
[177] Hurley Direct at 18.

million, and the present value of the energy price mitigation benefit would drop from $101 million to $70 million.[178] The resulting total benefit-cost ratio would drop from 1.37 to 1.26 (still above 1.0).[179]

In Staff's opinion, Avoided Capacity Cost – Demand, Capacity Price Mitigation – Demand and PeakRewards Operability are the most reliable of the additional benefits.[180] Staff would eliminate the Conservation Voltage Reduction ("CVR") benefit because in Mr. Hurley's opinion it is unclear whether the Company would have attempted to achieve the same amount of savings with a non-AMI CVR solution, as well as the Customer Reliability, Reduced Theft and Storms benefits because of the many assumptions built into the calculation of these benefits that are uncertain.[181]

On Surrebuttal, Staff witness Hurley made one modification. Staff believes that OPC witness Chernick made reasonable arguments to lower the value of the Energy Price Mitigation benefit, which lowers the benefit from $101 million to $18 million.[182]

BGE Response to Various Positions

On rebuttal, BGE witness Mark D. Case stated that OPC's proposed adjustments to provide customers with operational savings achieved in between BGE rate cases from 2012 to 2016 is an attempt to re-litigate an already settled issue.[183] Also, OPC witness Effron's computation includes costs that have not been incurred and therefore are not even included in BGE's cost of service yet.[184] Mr. Case maintains that the recovery of

[178] Hurley Direct at 20.
[179] Hurley Direct at 20.
[180] Hurley Direct at 22.
[181] Hurley Direct at 24-25.
[182] Surrebuttal Testimony and Exhibits of Daniel J. Hurley, March 21, 2016 ("Hurley Surrebuttal") at 2-3.
[183] Prepared Rebuttal Testimony of Mark D. Case, March 4, 2016, ("Case Rebuttal") at 6.
[184] Case Rebuttal at 16.

retired legacy meter costs over 10 years was resolved with the settlement agreement in Case No. 9355.[185] Mr. Case stated that the inclusion of sunk costs in the cost-benefit analysis would contradict the cost-effectiveness determinations of energy efficiency and demand response programs in EmPOWER Maryland proceedings.[186] He stated that including SER bill credits as a cost contradicts OPC's positions regarding PeakRewards program bill credits in Case No. 9154 and the SER bill credits in Case No. 9208 as well as the Commission's standards in the EmPOWER Maryland proceedings to assess whether energy efficiency and demand response programs should be approved as cost-effective.[187] Mr. Case contends that legacy meters should be treated as all other plant assets and remain in rate base to ensure full recovery of costs.[188] He states that to do otherwise would penalize a utility for replacing an asset not fully depreciated, even if the new technology provided savings and other benefits to its customers.[189] Lastly, Mr. Case notes that OPC's proposed revenue requirements do not incorporate the full impact of the $136 million OPC proposes in write-offs, but would impact BGE's rates for 10 years because OPC proposes to amortize the disallowances and credits over 10 years.[190]

BGE witness Vahos also testified in rebuttal on these matters. He believes the language in Order No. 83531 in Case No. 9208 is clear and that the Commission specifically directed BGE to defer into a regulatory asset the net depreciation and amortization costs related to meters and excluded the word "net" in its directive to defer

[185] Case Rebuttal at 6.
[186] Case Rebuttal at 6-7.
[187] Case Rebuttal at 7.
[188] Case Rebuttal at 18.
[189] Case Rebuttal at 19.
[190] Case Rebuttal at 22.

the incremental costs to implement the smart grid.[191] Mr. Vahos compared the language in Order No. 83531 in Case No. 9208 with the language in Pepco's smart grid Order. Mr. Vahos notes that Pepco (and Delmarva) proposed to defer into a regulatory asset all operational savings as an offset to incremental costs, and that the Commission approved that proposal.[192] BGE contends that the plain language of the two orders was clear in that the utilities would either flow operational savings through to customers during deployment or defer operational savings until incremental cost recovery was determined, but not both.[193] As further support, BGE notes that the Commission in Order No. 83531 went on to state that "the only direct savings the customers forego during the deployment years if we do not approve a tracker are the $15 million in reduced meter reading costs that BGE would pass through."[194] Mr. Vahos also believes OPC witness Effron's $31 million disallowance is duplicative of OPC's recommended disallowance of smart grid costs over benefits.[195] Lastly, Mr. Vahos responded to DOD witness Shpigler's testimony.

Company witness Pino indicated in rebuttal that OPC made errors in its calculation of market-side benefits. Mr. Pino contended that OPC double counted the free-ridership effects on the benefits associated with the SER program, that OPC erred in applying a free-ridership reduction to the energy quantity settled with PJM in the determination of wholesale energy revenue associated with the SER program, and that OPC neglected to adjust the Installed Capacity to Unforced Capacity in the capacity price

[191] Prepared Rebuttal Testimony of David M. Vahos, March 4, 2016 ("Vahos Rebuttal") at 12.
[192] Vahos Rebuttal at 13.
[193] Vahos Rebuttal at 14.
[194] Vahos Rebuttal at 14.
[195] Vahos Rebuttal at 15.

mitigation benefit.[196] In Table 1 of his rebuttal testimony, Mr. Pino noted the cases in which the Commission has recognized the methodologies BGE used in this case for capacity price mitigation, avoided T&D cost, and avoided capacity cost.[197] Mr. Pino agreed that OPC's recommendation to adopt the 2016 PJM load forecast is reasonable, that adoption of OPC's recommended updated forward wholesale energy prices is reasonable, and that the modifications made by OPC to the energy price mitigation methodology are reasonable.[198] Mr. Pino agreed that there is some load shifting by SER participants but stated that the problem is measuring it.[199] Mr. Pino testified that the sum of energy consumption increases before and after the SER pilot events was about 10% of the sum of energy consumption reduction occurring with the event period.[200]

BGE submitted rebuttal testimony of Michael B. Butts responding to, *inter alia*, OPC witnesses Brockway and Lanzalotta's testimonies, and to Staff witness Hurley's testimony.[201] BGE submitted rebuttal testimony of Dr. Ahmad Faruqui in which he responded to OPC witnesses Chang and Chernick with respect to free ridership, opined that inclusion of the undepreciated book value of legacy meters as a cost in the cost-effectiveness analysis would be inappropriate, that SER bill credits should not be considered as a cost, and that the Company should be permitted full recovery of its investment in legacy meters.[202]

[196] *See* Rebuttal Testimony of William B. Pino, March 4, 2016 ("Pino Rebuttal").
[197] Pino Rebuttal at 10.
[198] Pino Rebuttal at 20, 22.
[199] Pino Rebuttal at 21.
[200] Pino Rebuttal at 21.
[201] *See* Prepared Rebuttal Testimony of Michael B. Butts, March 4, 2016 ("Butts Rebuttal").
[202] *See* Rebuttal Testimony of Ahmad Faruqui, March 4, 2016 ("Faruqui Rebuttal").

In surrebuttal, Company witness Pino continues to argue that the cost-effectiveness framework that the Commission approved in Case No. 9154 applies to both energy conservation and demand response programs.[203]

<u>Testimony at Hearings</u>

<u>BGE</u>

At the hearings in this matter, BGE witnesses were cross-examined by the parties and the Commission. BGE witness Butts testified that the additional AMI expenditures of $16.6 million he mentioned in his pre-filed direct testimony were additional expenditures due to both opt-out customers and non-responsive customers.[204] BGE witness Butts testified about potential additional future uses of the Company's smart grid system.[205] Mr. Butts also testified about how the smart grid system better enables and lowers the cost of its conservation voltage reduction ("CVR") program.[206] With regard to the useful life of the smart meters, Mr. Butts explained that the system is to be supported and not be obsolescent for 15 years; he believes the equipment itself can last 15 years or longer.[207] When questioned about the number of meters yet to be installed, Mr. Butts explained the devices that are in exception status and what the Company is doing to reduce the number in that category.[208] Mr. Butts believes that BGE's opt-out rate (4 percent) is higher than Pepco's (1 percent) due to an active group of citizens opposed to smart meters that petitioned customers in BGE's service territory.[209] He testified that the

[203] *See* Prepared Surrebuttal Testimony of William B. Pino, March 21, 2016 ("Pino Surrebuttal").
[204] Transcript of proceedings ("Tr.") at 31-32.
[205] Tr. at 33-35.
[206] Tr. at 38-39.
[207] Tr. at 41.
[208] Tr. at 45-47.
[209] Tr. at 47-48.

ongoing costs in BGE's cost effectiveness analysis are related to trained call center personnel.[210] Mr. Butts indicated that the updated figure for the cost of the entire deployment of the smart grid initiative is $503 million, which includes not only meters, but also several IT systems and two-way communication infrastructure.[211] And, after at least another $300 million is invested in subsequent years, Mr. Butts testified that the benefits of the smart grid initiative exceed those costs on a 2 to 1 net present value basis.[212] Mr. Butts explained how Commission Orders which allowed customers to opt-out resulted in increased installation costs.[213] Mr. Butts explained his calculation of the storm savings benefits of reducing the length of storms and avoided truck rolls.[214]

On cross examination by OPC, BGE witness Pino admitted that no BGE witness provided testimony disputing OPC witness Chernick's conclusion that BGE's peak time rebate program will not result in any distribution avoided cost.[215] When asked about Mr. Chernick's testimony regarding PJM's re-simulation of its load model to estimate savings from BGE's peak time rebate program, Mr. Pino disputed Mr. Chernick's conclusion that there is very little value in the SER program from the perspective of peak load reduction.[216] Mr. Pino discussed the transition that will occur in the PJM market when base resources expire at the end of Delivery Year 2019-2020; BGE will be exiting the supply market and becoming a demand-only resource. Mr. Pino discussed BGE's approximately 800-megawatt demand response (DR) portfolio, of which nearly half is SER that Mr. Pino believes is providing PJM an extremely valuable service for grid

[210] Tr. at 48-49.
[211] Tr. at 49.
[212] Tr. at 50.
[213] Tr. at 65-68.
[214] Tr. at 78-80.
[215] Tr. at 239-240.
[216] Tr. at 247.

reliability.[217] Mr. Pino argued that PJM will rationally have to adjust its load forecasts when PJM sees a "cliff" in the peak demand coming out of the supply market and into a peak demand reduction.[218] Mr. Pino stated that there are two ways for customers to save money – in the allocation of the residential capacity obligation based on peak load share, and then once PJM recognizes lower purchases, PJM will buy less capacity.[219] Mr. Pino admitted, however, that Mr. Chernick's testimony reflects how PJM currently performs load forecasting with respect to non-monetized demand response.[220] Mr. Pino testified about BGE possibly extending SER to be an annual product, as well as other ideas the Company has considered, so as to qualify as a Capacity Performance[221] product.[222] He admitted that the surcharge for the PTR bill credits includes wholesale revenue from PJM, which operates to reduce that surcharge.[223]

Mr. Pino testified as to BGE's position of not including thermal discomfort or inconvenience experienced by customers, or voluntary measures taken by customers, as costs in its cost-effectiveness analysis.[224] Mr. Pino testified that the $1.25 per kilowatt hour rebate in the SER program is not compensation paid to customers, but rather a

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[217] Tr. at 248.
[218] Tr. at 249-250.
[219] Tr. at 253-255.
[220] Tr. at 257-258.
[221] On December 12, 2014, in FERC Docket No. ER15-623, FERC approved PJM's Capacity Performance proposal, which was designed to provide greater assurance of delivery of energy and reserves during emergency conditions, including through the establishment of substantial charges for non-performance. *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015). Several intervening parties to that docket protested that PJM's Capacity Performance construct would "create[] unnecessary barriers to entry to demand response" and "functionally eliminate[]" the participation of demand response in PJM's capacity market. 151 FERC ¶ 61,208 at PP 61-62. Although PJM proposed to temporarily retain its existing capacity product (referred to as "Base Capacity,") FERC approved PJM's plan to quickly replace Base Capacity with Capacity Performance over the next few PJM capacity auctions. For the 2020-2021 Delivery Year (the auction for which is held in May 2017), PJM will procure 100 percent of the region's capacity resources as Capacity Performance resources. *Id*. at P 28. (Check cite – FERC Order at P. 28?)
[222] Tr. at 343-346.
[223] Tr. at 347.
[224] Tr. at 284-288.

financial incentive for customers to reduce load in the form of a transfer payment paid by all customers to a subgroup of customers.[225] Mr. Pino explained that BGE's benefit/cost test is not a strict total resource cost ("TRC") test in that it included avoided air emissions cost as a benefit, which the Commission in Order No. 87082 directed to be included in a societal cost test.[226]

Mr. Pino admitted that BGE does not account for load shifting prior to an energy savings event day, or deferral of usage after the savings event is over; BGE's believes that the amount of energy reduction is not very material as compared to the peak demand reduction, which is the focus of the SER.[227] Mr. Pino testified that about one-third of BGE customers have online accounts and are using the SEM portal.[228] Mr. Pino maintained that the Company's estimate of savings from SEM is conservative.[229]

In his oral testimony, BGE witness Faruqui more fully explained the regression analysis that is done on the SER participant group, and how it is applied on all summer days so as to understand how changing weather conditions affect customer loads.[230] The result BGE calculated was that on average customers lower their energy use by 17.7 percent on energy savings days.[231] Dr. Faruqui discussed the different methods of defining cost-effectiveness, and confirmed his written testimony that he does not believe the cost effectiveness analysis in this case should include a cost for the imposition on customers for their change in behavior, and that transfer payments are not counted as

[225] Tr. at 289.
[226] Tr. at 320-322.
[227] Tr. at 351-352.
[228] Tr. at 353-354.
[229] Tr. at 355-362.
[230] Tr. at 404-406.
[231] Tr. at 406-412.

costs in the TRC perspective.[232] Dr. Faruqui stated that there is no way to measure the cost of imposition on customers that is practical in a TRC test calculation.[233] Dr. Faruqui testified that in his opinion, the Commission should have a consistent methodology for how it treats rebates in efficiency and demand response programs as both types of programs are based on incentivizing customers to change behavior.[234]

Dr. Faruqui discussed how upgrading to smart meters before legacy meters were fully recovered may represent an extraordinary expenditure, but that the benefits of the new technology should not be delayed.[235] In Dr. Faruqui's opinion, whether the cost of legacy meters should be considered in the cost-effectiveness analysis, and whether you allow a return on legacy meters that are no longer being used, are two separate issues.[236]

BGE witness Vahos testified at the hearings on several issues including cost recovery of the smart grid regulatory asset. Mr. Vahos testified that if the Commission were to direct that the regulatory asset be amortized over a ten-year period, the revenue requirement would be reduced by approximately $28 million.[237] Mr. Vahos testified that it is appropriate for the Commission to consider gradualism as another aspect of its decision-making process, and that a 10-year life would be reasonable.[238] When questioned as to why post-test year smart grid costs should be treated differently than legacy meters put into service in the past, Mr. Vahos testified that it is his position that if the Company does not get recovery of the full regulatory asset in this proceeding, then it will have a regulatory asset leftover, and that the residual regulatory asset would continue

[232] Tr. at 418-427.
[233] Tr. at 451.
[234] Tr. at 437-438.
[235] Tr. at 439-443.
[236] Tr. at 464-465.
[237] Tr. at 849-850.
[238] Tr. at 850.

to accrue a return.[239] So even though the post-test year portion of the regulatory asset is an estimate, Mr. Vahos believes that it is best to not continue to accrue carrying costs into a future rate case.[240]

BGE witness Case expounded upon Company Exhibit 31.[241] Mr. Case noted that other commissions around the country are investing in smart grid technology, and that BGE has things that other commissions do not – the $200 million DOE grant and significant market side benefits.[242] Mr. Case mentioned qualitative and service benefits and modernization of the grid as preparation for new technologies as unquantified benefits in addition to the economic benefits that were quantified in this case.[243] Mr. Case explained that the Company is seeking recovery of the legacy meter costs and a return at the Company's authorized cost of capital for that investment.[244] Mr. Case testified that the settlement in Case No. 9355 established that BGE would recover the cost of the legacy meters over a ten-year amortization.[245] Mr. Case concurred that 15 years is a reasonable estimation for the useful life of the new smart meters, but believes that in 2010 in Case No. 9208, the Commission expressed a preference to use a shorter depreciable life because the smart grid technology was so new.[246] Mr. Case defended the Company's request that customers be required to pay for the new meters as well as the residual unrecovered cost of the old legacy meters.[247] Mr. Case explained how in each rate case that has been filed since deployment of the new system whatever level of

[239] Tr. at 851.
[240] Tr. at 851-852.
[241] Tr. at 978 *et seq.*
[242] Tr. at 1053.
[243] Tr. at 1053.
[244] Tr. at 1082-1083.
[245] Tr. at 1086-0187.
[246] Tr. at 1088.
[247] Tr. at 1092.

savings the Company had achieved at that point in time was flowed through to ratepayers.[248] Mr. Case also discussed the proxy approach the Company used to calculate avoided transmission and distribution costs, because the alternative requires a very complex analysis.[249]

OPC

OPC witness Maximilian Chang explained that in his written testimony he was trying to clarify the difference between what is done in a cost effectiveness screening versus what is done in a program implementation, however, he conceded that he did not know specifically how incentive payments are treated in the PeakRewards program.[250] On cross-examination, Mr. Chang also conceded that many of tools associated with the SEM program cannot be utilized with legacy meters.[251] Mr. Chang believes demand response cost effectiveness is an evolving area in the electric utility sector and that California has started treating bill credits as a proxy for participant cost.[252] Mr. Chang admitted that if his estimate of disallowed benefits in the amount of approximately $700 million ($280 million for SEM, $176 million for avoided T&D, $249 million in market benefits) contained an error on the order of five percent, or $35 million, and if the Commission did not agree that peak time rebate costs should be included in the cost effectiveness analysis, the benefit-cost ratio would be 1.0.[253] Mr. Chang believes that the

[248] Tr. at 1094-1095.
[249] Tr. at 1101-1102.
[250] Tr. at 1420-1421.
[251] Tr. at 1423-1425.
[252] Tr. at 1431.
[253] Tr. at 1436-1438.

Commission in 2010 in Case No. 9208 indicated that the cost of legacy meters would be a consideration in a cost-effectiveness analysis.[254]

On cross-examination by the Commission, OPC witness David J. Effron discussed the complexities of extending the depreciable life of the smart meters from 10 years to 15 years when in the Company's benefit-cost analysis, benefits are being considered over a 10-year horizon.[255] OPC witness Effron testified that extending the depreciable life of smart meters from 10 to 15 years would not have any impact on the present value cost of the meters, but that the remaining balance to be recovered on which the Company would earn a return would be greater years in the future.[256] Mr. Effron stated that if the Commission were to extend the depreciable life of smart meters to 15 years, while continuing to look at benefits over 10 years, per the Company's benefit-cost analysis, ratepayer costs would be reduced in the short term, however, ratepayers would pay more later due to accumulating interest.[257]

OPC witness Paul Chernick believes that in Order No. 87802 when the Commission approved the Variable Resource Requirements (VRR) methodology to calculate capacity price mitigation as presented by the EmPOWER planning group, the Commission approved it for the purposes of that round of EmPOWER program analysis.[258] Similarly, Mr. Chernick testified that the Commission was clear in Order No. 87213 that its decision to approve the VRR methodology applied to that round of the EmPOWER program, that it was open for review at the next peer review, and that the

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[254] Tr. at 1450-1451.
[255] Tr. at 1575, *et seq.*
[256] Tr. at 1576.
[257] Tr. at 1576.
[258] Tr. at 1585-1586.

Commission would take other steps to avoid inappropriate emphasis on demand response due to an excessive capacity price mitigation calculation.[259] Mr. Chernick acknowledged that the Commission approved the Phase II-A metrics report on December 11, 2012, which included a benefit for avoided transmission and distribution.[260] In his opinion there is a difference between a metric report which reflects potential savings based on assumptions, and actual reduction in transmission and distribution needs.[261] Mr. Chernick still takes issue with the Company's analysis of the benefits of the SER program because the Company's regression analysis is performed after removing customers whose usage appeared to have increased, and therefore in his opinion the Company has not properly accounted for the effect of free ridership.[262] When asked about his calculation of a reduction to benefits based on load shifting, Mr. Chernick contended that the data to better estimate the percentage reduction was not provided by BGE despite the fact that it is available from smart meters.[263] Mr. Chernick stated that his estimates are the best he could do with the data he was provided, and he believes them to be more reliable estimates than the Company's estimates.[264] When asked about the difference between the EmPOWER program and the smart grid initiative, Mr. Chernick stated that we now have better information on how the market works, how the load forecasting works, and the timing of the load reductions and how they intersect with the peaks.[265] Mr. Chernick stated that many of his points about avoided T&D and avoided capacity and capacity price mitigation are greatly reduced or go away entirely if there is load

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[259] Tr. at 1586.
[260] Tr. at 1588.
[261] Tr. at 1589.
[262] Tr. at 1590-1595.
[263] Tr. at 1595-1599.
[264] Tr. at 1600-1601.
[265] Tr. at 1607.

reduction over many hours, however, he believes the SER program is only hitting some of the high load hours.[266] Mr. Chernick stated that demand response is not energy, but that if SEM operates as the Company states it will, the conservation effects will produce some real savings.[267]

On cross-examination, OPC witness Brockway discussed possible treatment for the recovery of legacy meters, noting that in the case from California she cited in her pre-filed testimony, the California commission permitted an amount of recovery on legacy meters but reduced the rate of return applicable to the unamortized balance, thereby disallowing full recovery on the asset, treatment which Ms. Brockway described as extraordinary.[268] Ms. Brockway acknowledged that a part of the settlement agreement in BGE's recent depreciation proceeding, Case No. 9355, the parties agreed to a ten-year recovery period for legacy meter costs, based on a depreciation schedule that was attached to and incorporated into the settlement agreement.[269]

Staff

Staff witness Patricia Stinnette confirmed her recommendation that the Commission allow the actual costs in the smart grid regulatory asset which are known through February 2016.[270] Ms. Stinnette's opinion is that costs from March to May of 2016 would go into the same regulatory asset to be considered at the Company's next rate

[266] Tr. at 1605.
[267] Tr. at 1606.
[268] Tr. at 1829-1830.
[269] Tr. at 1836-1837.
[270] Tr. at 1626.

case, and that costs after June 4, 2016 (the date of the Order in this case), would no longer go into a regulatory asset.[271]

On cross examination by OPC, Staff witness Daniel Hurley testified that in addition to the TRC cost effectiveness analysis, the Commission considers other factors such as bill impact in accordance with PUA §7-211, and does not approve large incentives for programs if the bill impact is too high.[272] Mr. Hurley testified that in this case the Commission can consider the rebate costs, not in the TRC cost effectiveness analysis, but in the context of the bill impact.[273] Mr. Hurley acknowledged that in order for the capacity obligation to be reduced as BGE predicts, PJM has to recognize the load reduction capability.[274] Mr. Hurley testified that while he did not investigate whether the benefits attributable to the SEM program could be achieved without smart meters, he understands that BGE's smart grid initiative was designed with smart meters being an enabling part of the program, which is why the costs of the program have not been recovered yet.[275] Mr. Hurley distinguished the SEM program from Potomac Edison and SMECO programs that provide high energy users with behavior reports not enabled by smart meters.[276] Mr. Hurley believes that the Commission, after consideration of all the testimony from all the parties in this case, will determine whether there is a risk that avoided costs will not occur as predicted, however, in his opinion, the risk is very low.[277]

Mr. Hurley testified that the working group took the AMI metrics from Case No. 9208 and from the PeakRewards program and adopted them in EmPOWER and the

[271] Tr. at 1626-1627.
[272] Tr. at 1873.
[273] Tr. at 1875-1876.
[274] Tr. at 1885.
[275] Tr. at 1889.
[276] Tr. at 1890.
[277] Tr. at 1903.

Commission approved the metrics for use in the EmPOWER program. Mr. Hurley stated that Staff has always taken the position that benefits across energy efficiency, demand response and AMI programs should be treated consistently, so as to avoid inconsistent results.[278] Mr. Hurley acknowledged that the benefits from CVR were part of the Phase II-B metrics that were supported by Staff but that did not become a consensus document approved by the Commission.[279] Mr. Hurley agreed that calculating the avoided cost associated with CVR as a benefit is more conservative than focusing on the energy savings from CVR.[280] The Phase II-B methodologies filing also noted the potential for other benefits such as reduction in unaccounted for energy, direct load control operational effectiveness, reduction in storm restoration due to meter pinging, and reduction in bad debt, which Mr. Hurley expects will be supported by information obtained through the smart grid in the future.[281]

Mr. Hurley opined that if the cost-benefit analysis was extended to 15 years, there could be higher benefits, with only the same ongoing costs.[282] With regard to the free ridership issue, Mr. Hurley noted that PJM does not factor in free ridership.[283] Mr. Hurley testified that he monitors the quarterly smart meter costs as part of his analysis of the smart meter deployment, and that he does not recommend that the Commission disallow any of the costs in this case, including the costs associated with the customer education plan.[284]

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[278] Tr. at 1905-1906.
[279] Tr. at 1914-1915.
[280] Tr. at 1916.
[281] Tr. at 1915 *et seq.*
[282] Tr. at 1930-1931.
[283] Tr. at 1931-1932.
[284] Tr. at 1935-1936.

Commission Decision

Six years ago the Commission granted the Company's request to proceed with deployment of its Advanced Metering Infrastructure ("AMI" or smart grid initiative) in Case No. 9208, subject to certain conditions. Specifically, the Commission ordered the deferred recovery of smart grid-related costs until such time as the Company had delivered a cost-effective system.[285] Deferred cost recovery was deemed appropriate by the Commission in 2010 as a means to allocate risks between the Company and its customers while also synchronizing the costs borne by customers most closely with the onset of benefits.[286] While the Commission adopted this deferred cost recovery structure with the intention of protecting customers from the possibility that they would pay for an AMI system found ultimately to be not cost-beneficial,[287] that decision has yielded unintended consequences. However well-intentioned the 2010 Commission decision regarding cost deferral was, we now must rule on the recovery of several years' of accumulated deferred AMI costs, with the potential of causing rate shock upon incorporation of prudently-incurred smart grid-related costs into base rates. Further, it is evident based on public comments received in advance of the evidentiary hearings that some degree of disconnect persists among ratepayers regarding smart grid cost recovery

[285] Order No. 83531 at 50, ¶2. Further, the Commission noted that at the time the Company delivered a cost-beneficial AMI system, the Company could seek cost recovery in base rates. *Id.* Thus, we reject any party's assertion that the instant proceeding was not the appropriate forum in which to assess whether BGE's AMI initiative is cost-beneficial. We note that although the term "cost-effective" was used in Order No. 83531, the proper term is "cost-beneficial" since the Commission is conducting a cost-benefit analysis that compares costs to benefits expressed in dollar values.

[286] *Id.* at 35.

[287] The Commission stated that "[b]y directing cost recovery through a properly structured regulatory asset, recovered in base rates, we find that customers are appropriately protected against the possibility that they will pay in full for an AMI system that would not be cost-effective." *Id.* at 47.

and the realization of benefits derived from the AMI initiative.[288] In short, while a portion of market-side benefits and operational savings from the Company's AMI deployment began flowing through to customers immediately in rate cases over the past six years, the cost recovery of the underlying enabling infrastructure remained deferred and subject to additional carrying costs. An alternative approach could have been to allow partial cost recovery over the past six years, in concert with the phase-in of benefits derived from AMI deployment. However, the 2010 decision cannot be undone.[289] Thus, we are now charged with determining whether the Company has satisfied its burden of proof regarding the delivery of a cost-beneficial AMI system; the Commission has previously recognized that the Company is entitled to recover the prudently-incurred costs associated with the smart grid initiative, as well as an appropriate return.[290]

As an initial matter, we note that several of the metrics used to quantify benefits, both operational benefits and market-side benefits, are metrics that are reported quarterly in Case No. 9208, metrics that arose out of working group meetings in consensus documents submitted to the Commission for approval. Many of the metrics have been used in the EmPOWER proceedings as well, for purposes of screening prospective energy efficiency programs in the context of cost-effectiveness determinations. Thus, we agree that many of the categories themselves – Operational Savings, Avoided Transmission and Distribution Infrastructure, Avoided Capital Expenditures, DOE Grant,

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[288] We note that the Company bears at least some responsibility for this disconnect, likely attributable to deficiencies in its customer education efforts. While this shortcoming does not speak to the threshold question of whether the AMI system is cost-beneficial, it does impact a prudency determination regarding recovery of customer education-related costs, discussed *infra*.

[289] We acknowledge the uncertainties the Commission faced given that AMI was a relatively new technology in 2009 when BGE's proposal was first filed. As Judge Nazarian observed, "Unlike hindsight, foresight is not 20/20." Newell v. Johns Hopkins Univ., 215 Md. App. 217, 220 (2013).

[290] Order No. 83531 at 38.

Capacity Revenue, Capacity Price Mitigation, Energy Revenue, Energy Price Mitigation, and Energy Conservation – are the categories of core benefits that should be quantified as part of the necessary cost-benefit analysis.

As Staff pointed out, some of the other benefits the Company included in its analysis constitute benefits that were either established as non-consensus AMI metrics or developed outside the AMI working group process altogether. Staff termed these "Additional Benefits," which included valuations of: operational savings associated with storms; customer reliability/reduced theft; conservation voltage reduction (CVR); avoided capacity costs; and avoided emissions.[291] Staff articulated clearly, however, that it was not saying that these categories were of no benefit; rather, Staff did not assign a value to these Additional Benefits in large part because they were not needed to verify that the Company's smart grid initiative is cost-beneficial. While we recognize the value in Staff's conservative approach to this analysis, we find that a utility should not be limited to the aforementioned categories of core benefits in an attempt to demonstrate that its AMI system is cost-beneficial. Indeed, we find that should the record support inclusion of additional benefits in a cost-benefit analysis, as it does to some extent here, nothing in this Order or in Commission Order No. 83531 requires a wholesale disallowance of the additional benefit categories.

Two overarching adjustments to the benefits quantified by the Company in its analysis were presented for our consideration: the removal of Smart Energy Manager

[291] We note, however, that several of these benefits were defined subsequent to the AMI working group process by methodologies accepted by the Commission in the EmPOWER proceedings. For example, in a July 2015 Commission Order, we found it appropriate to adopt an Itron quantified business-as-usual value equivalent for the non-energy benefit category of avoided air emissions, defined as \$0.002/kWh of energy savings. Order No. 87082 (July 16, 2015) at 15, note 70.

(SEM) derived benefits from all categories; and the use of an alternative inflation rate. OPC witness Chang removed the benefits of the Smart Energy Manager (SEM) program from all benefit categories because he believes that these benefits could have been achieved without smart meters. Mr. Chang acknowledged, however, that many SEM tools would not be available without smart grid interval data.[292] Moreover, to negate the benefits of the SEM program runs contrary to the Commission's explicit authorization of BGE to proceed with its smart grid initiative in Case No. 9208 given that the SEM program is part of the Company's integrated smart grid system. We therefore decline to apply OPC's suggested reduction in benefits and thus begin our category-by-category review of the Company's analysis assuming the inclusion of SEM benefits in each.

The second overarching adjustment presented for our consideration pertained to the inflation rate used by the Company in calculating its operational benefits; BGE assumed an inflation rate of three percent (3%). Staff does not believe a 3% inflation rate is appropriate and instead used an inflation rate of 2.3% based on a 15-year average from 2001-2015. We accept Staff's recommendation to use an inflation rate of 2.3% because it incorporates a significant time period over which the fluctuation of inflation rates is smoothed out.

Utilizing an inflation rate of 2.3%, and opting for now to adopt Staff's conservative approach of analyzing core benefits, as discussed more fully below, we accept Staff's calculation of benefits for Operational Savings of $174 million.

For the Avoided Transmission and Distribution infrastructure categories, BGE used the marginal unit cost approach as a proxy for the long-term value of the avoided

[292] And the Company is not able to disaggregate the savings associated with the individual tools. Tr. at 1422.

T&D on a present value basis. The Company computed benefits of $115 million and $87.8 million for Avoided Transmission and Distribution, respectively. Staff accepted the Company's analysis,[293] recommending the Commission apply benefits of $94 million and $72 million to these categories. The marginal unit cost methodology utilized by BGE and Staff has served as a component of cost-effectiveness analysis in front of the Commission since the inception of the PeakRewards program and was used for quarterly metrics reporting in Case No. 9208; further, it has been used repeatedly in the evaluation of other utility companies' direct load control programs. Most recently, this methodology for valuing avoided T&D infrastructure was adopted as part of the Commission's proceeding on cost effectiveness in Order No. 87082, issued on July 16, 2015.[294] While OPC now asserts that the marginal unit cost approach results in overstated benefits (OPC recommended severe reductions to these numbers to $8 million and $6 million, respectively), we note that OPC has previously recommended adoption of the marginal unit cost approach to valuing avoided T&D.[295] OPC has not adequately explained its shift in reasoning, and has not convinced us that its current analysis is based on a workable methodology that produces more reliable results such that we should shift from our recent approval of the marginal unit cost approach. Given that no party has articulated a persuasive distinction between the application of the avoided T&D cost-

[293] Staff's recommended quantification of avoided T&D benefits differs from the Company's valuation due to the alternative inflation rate adopted by Staff, as discussed previously.
[294] *See* Order No. 87082 (July 16, 2015) at 10, stating that, "We find that the values derived from the Avoided Cost Study performed by Exeter Associates on behalf of MEA and the Power Plant Research Project ("PPRP") for avoided energy costs were appropriately adopted…" (citing ML#157744: *EmPOWER 2015 – 2017 Cost Effectiveness Framework* (Aug. 19, 2014)at 9-10).
[295] OPC recommended adoption of the avoided T&D infrastructure cost methodology in the 2015 EmPOWER proceeding on cost effectiveness. *See* ML##163617: *Office of People's Counsel Comments on EmPOWER Maryland* (Jan. 30, 2015) at 6, stating OPC's recommendation to "[a]dopt working group values, based on method and results from Exeter Associates study" for energy capacity, RPS compliance, avoided T&D, avoided water, and avoided heating fuel.

effectiveness assumption approved in our July 2015 EmPOWER proceeding and the avoided T&D cost-effectiveness assumption relied on by the Company in the instant proceeding,[296] we decline to deviate from what has been a consensus position in the EmPOWER docket.

We do note, however, that there is room for expanded avoided T&D benefits as part of the Company's continued commitment to realizing additional benefits stemming from smart grid deployment. Although in this proceeding we accept the method BGE used to compute avoided T&D infrastructure as a proxy for avoided T&D benefits in evaluating whether the smart grid initiative is cost beneficial, we will remain vigilant with regard to BGE fully utilizing smart grid technology to optimize its planning efforts for future T&D investment. We expect BGE to ensure that ratepayers realize a demonstrable return on their investment in smart grid technology. Therefore, as a condition of accepting BGE's calculation of avoided T&D infrastructure in the cost-benefit analysis, we will require that BGE file a Distribution Investment Plan within twelve (12) months of the date of this Order that sets forth how the Company will accomplish this goal. The required Plan shall analyze in detail the Company's strategy over the next five years for investing in its distribution system and shall include, among other things, specifics about how the Company's investment in smart meters will be utilized to improve the efficiency and effectiveness of the distribution network. In addition, the Company is directed to include as part of our next RM43 reliability metrics proceeding (during which SAIDI and SAIFI standards will be established for years 2020

[296] In fact, the avoided cost study that served as the basis for the EmPOWER cost effectiveness assumptions recommended that "avoided T&D be analyzed in the same way as is being done for the AMI proceeding." ML#157744: *EmPOWER 2015 – 2017 Cost Effectiveness Framework* (Aug. 19, 2014) at 10.

– 2023), an assessment of how AMI infrastructure is being incorporated into the distribution system plan and the role it is playing in supporting the network.

Of the remaining operational benefits categories, the parties did not dispute the Company's valuation of either the Avoided Capital Expenditures or the DOE Grant Benefit. With respect to the category of Avoided Capital expenditures, however, Staff applied its recommended inflation rate to arrive at a slightly lower benefit figure of $36 million, which we will accept based on our prior acceptance of Staff's 2.3% inflation rate. The parties accepted the Company's computation of a net present value of $60.2 million for the benefit associated with the DOE grant, and we will accept this amount as well.

After tallying the above operational benefit values for Operational Savings, Avoided T&D, Avoided Capital Expenditures, and the DOE Grant benefit, we arrive at Operational Benefits derived from the smart grid initiative of at least $436.2 million on a net present value basis, which importantly does not include amounts for categories that Staff designated as Additional Benefits. Of these additional categories, we note that OPC did not challenge the Company's benefit computations for Conservation Voltage Reduction (CVR) (Avoided Cost of Program), valued at $49.6 million on a net present value basis. Previously, the Commission directed all Maryland electric utilities to develop CVR programs due primarily to the large energy savings that can be achieved, as well as the high cost-effectiveness rating of the program.[297] We accept BGE's position that as a result of the smart grid initiative, BGE has avoided costs associated with a

[297] Order No. 84569 (Dec. 22, 2011) at 12.

standalone CVR system, and we find it appropriate to include these avoided costs as a benefit in our analysis.[298]

We note also that OPC did not dispute the Company's computation of other operational benefit categories deemed as Additional Benefits by Staff; specifically the quantification of benefits associated with increased customer reliability, reduced theft, and reduced consumption on inactive meters. Collectively, these operational benefits were valued by the Company at $161.6 million on a net present value basis, and thus their inclusion would significantly increase the total operational benefits attributable to BGE's smart grid imitative. While we decline at this time to recognize this category of Additional Benefits in our assessment of BGE's cost-benefit analysis (instead opting for now to adopt Staff's conservative approach), we note that the aforementioned benefits will likely be realized and supported by the Company with future data collection. We concur with Staff that the benefits derived from AMI with respect to enhanced customer reliability, reduced theft, and reduced consumption on inactive meters are certainly not valued at zero.

Similar to Operational Benefits, some of the Market Side Benefits were developed outside of the AMI working group process and do not have a consensus reporting metric stemming from that process, although the Commission has ruled previously on several of the methodologies in other contexts. The Market Side Benefits that *do* have an approved reporting metric developed jointly by the AMI working group include Capacity Revenue,

[298]BGE noted that it computed the benefit in this category based on avoided capital costs of $61.8 million but did not take credit for the energy and demand reductions associated with a CVR system, which the Company's representatives testified would have resulted in a larger benefit figure. Tr. at 1028-1030; Tr. at 1104-1105.

Capacity Price Mitigation, Energy Revenue, Energy Mitigation, and Energy Conservation.

Consistent with the methodology and reporting metric developed by the AMI working group, the parties accepted the Company's calculation of Capacity Revenue benefits of $42.6 million, which we also accept. OPC, however, contested the Company's calculation of the Capacity Price Mitigation benefit on the same bases generally as were asserted in last year's EmPOWER proceedings regarding cost-effectiveness screening methodologies. The Commission was unpersuaded at that time by OPC's position, and in July 2015, in Order No. 87082, the Commission accepted the majority's recommended DRIPE methodology, which BGE has relied on in this case to compute the Capacity Price Mitigation benefit derived from AMI.[299] We remain unconvinced by OPC's reasoning in regard to this issue, and note further that OPC did not offer any persuasive basis on which to distinguish our prior decision from the instant case. Further, Staff urged that the Commission should use consistent methodologies across energy conservation and demand response programs; we find it appropriate to do so, unless a reasoned and persuasive distinction can be articulated. Accordingly, we will accept for purposes of the cost-benefit analysis discussed here that Capacity Price Mitigation offers a benefit of $159 million on a net present value basis.[300]

For the category of Avoided Capacity Costs, OPC contested the Company's calculation of this benefit and Staff did not include this category in its analysis after deeming it an Additional Benefit. Although OPC agreed that there is some Avoided

[299] Pursuant to Order No. 87213, the Commission denied OPC's petition for rehearing with respect to the adopted Capacity DRIPE methodology.
[300] Note that because we have accepted Staff's recommended inflation rate, the net present value of this benefit equates to $159 million as opposed to the Company's calculation of $212.6 million.

Capacity Cost benefit and Staff observed that the benefit was not zero, we concur at this time with Staff's conservative approach to this category and note that we need not include this benefit in our analysis in order to find the Company's smart grid initiative cost-beneficial. We understand from BGE witnesses that the Company's calculation of Avoided Capacity Costs hinges on PJM adjusting its forecast once PJM fully transitions its demand response programs from the supply side to the demand side of its wholesale capacity market.[301] Accordingly, we direct BGE to file within six (6) months a plan for how the Company intends to tackle this issue with PJM in order to bring about the necessary adjustment to PJM forecasts in the future.

In calculating the Energy Revenue benefit, BGE assumed two emergency events per summer season while OPC proposed one-half of an event per summer season. Although Staff found the Company's forecast to be reasonable, Staff modeled the effect of lowering the number of emergency events from 2 to 1 per summer. We find the assumption of 1 event per summer reasonable and in line with our conservative approach to this analysis, and thus we accept an Energy Revenue benefit of $11 million on a net present value basis.

The benefit computed for Energy Price Mitigation was similarly contested. OPC submitted an analysis that incorporated different regressions than BGE's analysis. Staff agreed that OPC witness Chernick made reasonable arguments to reduce the value of this benefit to $18 million. BGE too conceded that OPC's analysis was reasonable.

[301] This Commission has been working, and will continue to work, with PJM to find ways to preserve Maryland's demand response programs, so that they are not severely diminished under PJM's proposed new paradigm.

Accordingly, we will accept a benefit of $18 million on a net present value basis for Energy Price Mitigation.

The benefit computed for Energy Conservation was also contested. OPC argued that the value of this benefit was overstated because of outdated wholesale energy prices, and because the Company's analysis did not properly account for load shifting and free riders. Thus, OPC witness Chernick reduced the value of this benefit to $95 million. BGE agreed that it would be appropriate to use updated forward wholesale energy prices and further conceded that there may be some reduction in the benefit due to load shifting, acknowledging that there was 10% load shifting in its SER pilot program. BGE maintained, however, that its regression analysis properly accounts for free riders, and Staff asserted that the issue of free ridership was moot in this context.[302] Therefore, while we decline to adjust the Company's calculated benefit due to potential free ridership for the reasons asserted by BGE and Staff, we will reduce BGE's benefit figure of $137 million for potential load shifting by the 10% BGE acknowledged, to $123 million on a net present value basis.

After tallying the above market-side benefit values for Capacity Revenue, Capacity Price Mitigation, Energy Revenue, Energy Price Mitigation, and Energy Conservation, we arrive at Market Side Benefits derived from the smart grid initiative of at least $353.6 million on a net present value basis, which does not include amounts for categories that Staff designated as Additional Benefits. Staff deemed the categories of Avoided Capacity Costs and Avoided Emissions as Additional Benefits, and while recognizing that the value of these categories was not zero, declined to include either

[302] Tr. at 1931 – 1932.

category in its assessment of the Company's cost-benefit analysis. OPC too conceded that these remaining two categories of market-side benefits represented net positives for customers, and if we accepted OPC witness Chernick's position on Avoided Capacity Cost benefits, we could add $9 million to the tally of market-side benefits attributable to the Company's smart grid initiative. Moreover, OPC accepted the Company's computed benefit for Avoided Emissions of $3.9 million. We decline, however, at this time to include a valuation of either Avoided Capacity costs or Avoided Emissions in our assessment of the Company's cost-benefit analysis, noting instead that this conservative approach supports an ultimate conclusion that the Company has delivered a cost-beneficial AMI system.

Given that no party contested the costs of the Company's smart grid initiative on a quantitative basis, we accept that the Company's actual costs associated with AMI deployment are $653.8 million. This amount does not include the unamortized balance of the legacy meter asset, which we believe constitutes a sunk cost that is not appropriately included in the cost-benefit analysis for this new initiative. We also find it inappropriate, for the reasons stated by the Company in the record, to include SER bill credits as a cost in the cost-benefit analysis. We instead view these bill credits as transfer payments. OPC did not persuade us that there was particular justification for its change in position on this issue, or a reasoned basis for the Commission to deviate from an analysis OPC endorsed, and the Commission accepted, in the recent past.

As we stated above, Operational Benefits attributable to the Company's smart grid initiative equal or exceed $485.8 million.[303] Further, we find that Market Side Benefits stemming from BGE's AMI system equal or exceed $353.6 million. As part of this valuation, we did not include the Company's computed value for certain Additional Benefits within the Company's Operational Savings category – benefits associated storms (reducing the length of storms and avoided truck rolls) or reduction in uncollectible write-offs. We also did not include any value for the Additional Benefits associated with enhanced customer reliability, reduced theft, or reduced consumption on inactive meters; nor did we include a valuation of the Additional Benefits on the market side of Avoided Capacity Costs and Avoided Emissions. We concur with Staff that incremental benefits in these areas have and will likely continue to accrue to customers moving forward; however, we also agree with Staff that a review of additional data regarding these benefits may be warranted prior to assigning a value to these categories. We anticipate and expect that the Avoided Capacity Cost benefits predicted by the Company will materialize, and avoided Emissions benefits will prove valuable as well. However, taking Operational Benefits of $485.8 million and minimum Market Side Benefits of $353.6 million, we reach a conservative benefit figure of $839.4 million, which is well above the AMI initiative stated costs of $653.6 million. Accordingly, we find that the Company has delivered a cost-beneficial AMI system.[304]

We also recognize that there is evidence in the record that the smart grid technology will produce benefits in the future that BGE did not attempt to measure in the

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[303] Operational Savings of $174M + Avoided T&D of $166M + Avoided Capital Expenditures of $36M + CVR Avoided Costs of $49.6M + DOE Grant Benefit of $60.2M = $485.8M, not including any amount for Reduction in Uncollectible Write Offs.

[304] Given this finding, we do not need to consider OPC's suggestion regarding a "hold harmless" credit.

instant proceeding. BGE witness Case testified that the next iteration of the Smart Energy Manager program will include a rates module that will allow customers to see how much their bill might go up or down if they moved from a flat rate to BGE's time-of-use rate[305], which could lead to adjustments out of the peak period into the off-peak period yielding direct cost savings to participating customers and indirect benefits to all ratepayers associated with the mitigated system peak demand.[306] New pricing options are enabled by smart meters, as well as measurement of solar output from homes and businesses. Thus, while OPC provided testimony that benefits attributable to the smart grid initiative were overstated, BGE testified about the areas in which the Company believes its analysis to be conservative and further offered examples in which currently unquantified benefits may continue to accrue and develop.[307]

2. ***Continued Reporting of Metrics***

OPC advocated for the continued collection and quarterly reporting of metric information regarding the smart grid initiative, as well as customer opt-out information. BGE has indicated a willingness to continue to report on smart grid-related metrics that

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[305] Tr. at 1082.
[306] Tr. at 1079-1080.
[307] As set forth above, the benefit associated with CVR was calculated as an avoided cost benefit, whereas the Company's representatives testified that including the energy and demand reductions associated with a CVR system would have resulted in a larger benefit figure. In addition to CVR, BGE noted that Smart Energy Manager benefits were calculated without gas residential customers. Mr. Case stated that the Company is seeing a benefit from gas customers of roughly two-thirds that of electric residential customers. In addition, Mr. Case indicated that the Company is rolling out the SEM program to commercial customers which he believes will produce additional benefits. Tr. at 1046-1047.

the Commission deems worthwhile.[308] We see no reason that this rate case would operate to halt the reporting that is ongoing in Case No. 9208, or further reporting in that case. The Company shall continue to report metrics as it has been in Case No. 9208, as well as provide additional reports as directed by the Commission.

3. ***Cost Prudency Review***

Although we find that BGE has proven that it has delivered a cost-beneficial AMI system, based on the costs BGE has and will incur as compared to the benefits that have materialized and will continue to materialize, we are still required under PUA §4-101 to set just and reasonable rates based only on necessary and proper expenses. Indeed, in Order No. 83531, issued in August 2010, the Commission noted in its authorization of BGE's AMI deployment that the Commission's "recognition of a regulatory asset is not an advance determination that all costs related to the Initiative are prudent. We recognize that 'prudent' does not mean 'clairvoyant' or 'perfect,' and that a proper prudency review should not subject the Company to an unfair, post hoc nickeling-and-diming. But we also will not deem any costs as 'prudent' in advance – the appropriate time to determine prudence is when recovery of the regulatory asset is sought."[309] Thus, as part of this case, the parties were expected to present evidence as to the prudency of the costs for which BGE is seeking recovery.

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[308] We note that in BGE's most recent Case No. 9208 filing, the Company reported that 49,212 residential customers were subject to BGE's opt-out fees, reflecting an opt-out rate of 4%. ML 190683 at 12. Although some of these customers have chosen affirmatively to reject a smart meter, a significant number of customers have been auto-enrolled into opt-out status - and consequently billed a $75 upfront fee and a recurring $5.50 monthly fee. We remain very concerned about the large number of auto-enrolled customers who BGE has not reached and remind the Company of its continuing obligation to serve these customers and provide them with access to smart meters.
[309] Order No. 83531 at 39.

Staff found reasonable both the deployment and post-deployment costs as calculated by the Company, noting that the deployment costs align closely with the metrics reported as part of the Phase I metrics in Case No. 9208, filed on a quarterly basis. OPC provided testimony disputing the prudency of the Company's customer education efforts. We agree that the Company's customer education efforts were not as successful as we expected in educating customers about the benefits of smart meters. Although BGE fulfilled the literal terms of its communication and customer education plan, the plan did not prevent customer resistance to the installation of the meters. We agree with OPC that BGE should have been able to anticipate that there would be a degree of customer resistance to smart meters given the experiences of other utilities in other jurisdictions; in fact, the Commission noted in 2010 that deployments in other states were expected to supply lessons on how not to deploy AMI and how not to (mis)communicate with customers.[310] The Company submitted that $16.6 million in costs associated with its smart grid initiative were related to customers affirmatively opting out of smart meter installations and customers who were non-responsive to BGE's outreach efforts. Because BGE should have been able to better anticipate that some customers would want to opt out of having smart meters installed in their homes, which would have allowed the Company to have an appropriate strategy for dealing with those customers ahead of deployment, we do not find it appropriate to pass on to ratepayers the resulting costs associated with these additional outreach efforts. Similarly, we agree with OPC that BGE's explanation for its failure to reach all of its customers is unsatisfactory. BGE has previously had difficulties reaching all of its customers when trying to contact

[310] *Id.* at 47-48.

them or gain access to their premises. BGE's customer education plan can be seen as deficient to the extent customers failed to respond to its requests to install smart meters in their homes. Therefore, we will disallow $16.6 million in costs that the Company stated were additional costs incurred related to the opt-out proceedings and resulting Commission decisions.[311] The resulting rate base and operating income adjustments are summarized in the next section.

Lastly, we disagree with our dissenting colleagues' characterization of our decision with respect to AMI cost recovery; chiefly, we take issue with their depiction of the Company's demonstrated benefits derived from the smart grid initiative as speculation and claimed benefits. On the contrary, the extensive operational and market-side benefits accepted in our assessment of the Company's cost/benefit analysis – valued conservatively at $839.4 million on a net present value basis – are grounded in methodologies accepted repeatedly by this Commission and routinely used by public utility commissions nationwide. Indeed, OPC was an active participant in the development of these methodologies and assumptions over the past six years. Furthermore, we note that by using OPC's own preferred methodologies, the cost/benefit ratio of BGE's AMI system ranges between 0.94 and 1.14 when excluding the SER bill credits as a cost in the cost/benefit analysis.[312] In short, we find that the Company has

[311] OPC does not agree with the Company's suggestion that the Commission's opt-out orders are to blame for BGE's rate of installation of smart meters.
[312] As discussed in this section, the SER bill credits constitute a "transfer payment." It would upend well-settled principles of cost-effectiveness testing adopted by the Commission if transfer payments were included in a cost-benefit analysis as OPC proposes. Tr. at 437-438.

delivered a cost-beneficial AMI system, and thus is entitled to cost recovery of prudently-incurred costs associated with the smart grid initiative, as well as an appropriate return.[313]

B. Adjustments to Rate Base and Operating Income

Rate base represents the investment a company makes in plant and equipment to provide safe and reliable electric service to its customers. Operating income is derived from the revenues the Company receives for electric service less the prudently incurred costs of providing service to customers. Adjustments to the Company's rate base request were offered, accepted or disputed by the various parties. We have reviewed the record and accept many of the uncontested[314] rate base and operating income adjustments, and resolve the disputed adjustments below.[315]

1. ***Smart Grid Initiative Adjustments***

a. *OIA 23/RBA 6: Smart Grid Regulatory Asset Post-Test Year*

We reject the Company's proposed Operating Income Adjustment 23 and Rate Base Adjustment 6. We disagree with BGE witness Vahos' conclusion that if the Company is not permitted to recover Smart Grid costs that are incurred after the test period and before the effective date of the new rates, BGE would be required to keep those costs in a regulatory asset. In Order No. 83531 in Case No. 9208, the Commission deferred cost recovery until BGE could offer proof that it had delivered a cost effective system. When it filed this base rate case, BGE submitted proof that it had delivered a cost-beneficial system, based on the test year ending November 30, 2015. We have

[313] Order No. 83531 at 38.
[314] OIA 26 addresses BGE's uncontested adjustment for its 2016 wage increase. Although we do not deny the adjustment, we ask that parties address wage increases outside the test period in the next rate case.
[315] *See* Appendix I for the Commission's calculation of the appropriate rate base, operating income and overall revenue requirement for rate making purposes.

determined that BGE is entitled to cost recovery of its smart grid initiative, however, that determination does not render all of BGE's costs prudent, nor does it mean that BGE is entitled to post-test year expenses as part of this rate case given the historical test year approach. Allowance of post-test year expenses is an exception to the rule, for such items as reliability spend. Costs related to BGE's smart grid system will continue to accrue. These ongoing costs, and costs that were incurred subsequent to the test year in this case, are to be expensed as normal expenses. These expenses may be recovered in future base rate proceedings to the extent they fall within the test year for those case(s).[316]

b. *Amortize Smart Grid Regulatory Asset Over 10 Years*

Although we find that BGE has shown the smart grid system to be cost-beneficial, we are extremely concerned about the level of increase that ratepayers will experience based on this Order. We believe it is appropriate to take steps to ease rate shock to the fullest extent possible. Therefore, we direct BGE to amortize the smart grid regulatory asset over 10 years as proposed by the parties in this case and which BGE conceded was reasonable. This results in an operating income adjustment of $10,051,000[317] for electric and an operating income adjustment for gas of $4,019,000.[318]

We will not, however, modify the depreciable life of the smart grid assets from 10 years to 15 years, despite the testimony at the hearings that the smart grid technology may have a useful service life of at least 15 years. A utility that is only in the preliminary

[316] In fact, we note that OIA 22 effectively provides for an appropriate amount of annual O&M expenses in the rate effective period (Vahos Direct at 12) meaning that BGE will recover its annual O&M expenses based on actual 2015 expenses going forward even if BGE does not file a rate case for over a year.
[317] Regulatory asset balance of $168,537,266 as of November 30, 2015 (Vahos Supplemental Direct, Exhibits at 28).
[318] Regulatory asset balance of $67,394,298 as of November 30, 2015 (Vahos Supplemental Direct, Exhibits at 28).

stages of deployment of smart grid technology may wish to consider whether 15 years is appropriate for the depreciable life of its new assets, but that is not the situation with BGE.

c. *Accrued Smart Grid Operational Savings*

BGE contends that the language in Order No. 83531 in Case No. 9208, as well as the Pepco Order in Case No. 9207, is clear in that the utilities were provided a choice to either flow operational savings through to customers during deployment or to defer operational savings until incremental cost recovery was determined, but not both. However, the "flow-through" that BGE proposed in Case No. 9208 was a tracker mechanism. As it turns out, BGE filed rate cases in each of the intervening deployment years, and, thus, operational savings flowed through to customers (though with lag as Mr. Effron points out) in the subsequent rate effective periods. However, BGE has not presented evidence that this type of "flow-through" was anticipated and understood by the parties in Case No. 9208, or formed the basis for the Commission's decision in Order No. 83531. Indeed, we do not believe such evidence exists.

We agree with OPC that the excess of the operational savings achieved over the amount credited to ratepayers should be offset by the deferred smart grid costs included in the recoverable smart grid regulatory asset. Ratepayers should not be worse off than they would have been under a tracker mechanism. BGE claims that this adjustment is unfair, yet BGE has not offered a reasonable explanation for why it should be given the preferential treatment of retaining a portion of the benefit of the smart grid savings for shareholders as compared to Pepco, whose ratepayers will receive credit for all of the smart grid savings. Although components of the smart grid regulatory asset were disclosed in the intervening rate cases filed during deployment, the regulatory asset did not affect the rates determined in those cases; thus, this adjustment does not, contrary to BGE's contention, constitute retroactive ratemaking. Accordingly, for electric we will make a downward adjustment to rate base of $9,643,000 and, consistent with our decision to amortize the smart grid regulatory asset over ten years, an operating income adjustment of $964,000.[319] The adjustments for gas are a downward adjustment to rate base of $4,639,000 and an operating income adjustment of $464,000.

d. *Return on Legacy Meters*

While we will allow the Company to recover the cost *of* its legacy meters that were retired as part of the Company's smart grid initiative, we find it is not appropriate for the Company to earn full recovery by earning a return *on* the unamortized balance of the legacy meters. We acknowledge that in Case No. 9355 the Commission approved as just and reasonable the rates resulting from a "black box" settlement between the parties, embedded in which was the question of a return *of* and *on* the legacy meters.[320] Despite serving as a signatory to the Case No. 9355 settlement, OPC now requests that this Commission disallow a full return of and on legacy meters, and the issue is squarely before the Commission. We find that these assets are in a different category from other assets in that the legacy meters were retired all at once while they still had useful life. Therefore, we agree with OPC that the Company is not entitled to full recovery *on* the

[319] We note that in making his calculations, Mr. Effron reflected Mr. Lanzalotta's 40% reduction to the savings attributed by BGE to reduced storm restoration costs, which reduced the overall electric operational savings by approximately 6.7%. Although we do not accept Mr. Lanzalotta's proposal, as set forth below, we incorporate Mr. Effron's 6.7% reduction because the record evidence is that while BGE disagreed with Mr. Effron's proposed adjustment, BGE did not dispute his calculation of accrued smart grid operational savings. Tr. at 742.

[320] In a "black box" settlement, the parties agree on the result without disclosing or agreeing on the various components.

unamortized balance of the legacy meters.[321] OPC describes its position as an equitable split between ratepayers and shareholders and we concur. Accordingly, rate base will be adjusted downward in the amount of $46,495,000 for electric, and for gas, rate base will be adjusted downward by $2,193,000.[322]

e. *Other Contested Adjustments*

Since we have found that the Company has delivered a cost-beneficial AMI system, as set forth above, OPC's proposed adjustment for a "hold harmless" credit is moot. OPC also proposed an operating income adjustment based on its theory that the savings attributable to reductions in storm restoration costs are overstated by the Company by 40%. Although we did not assign a value to the benefit associated with reductions in storm restoration costs for purposes of the cost-benefit analysis, some reductions have likely been the result of other reliability investments and distribution system upgrades. While a reduction in actual storm restoration costs might be appropriate, we are not convinced that it is correct to correlate the computed 40% reduction in customer interruptions (during milder weather years)[323] to a 40% reduction in the savings attributed to avoided truck rolls. Moreover, as OPC noted, the Company accounted for this to a degree, and thus, Mr. Lanzalotta's 40% reduction on top of the Company's reduction would be inappropriate. For these reasons, we cannot accept OPC's proposed operating income adjustment for rate year smart grid savings.

[321] We are not adopting what we see as an extreme position on the part of OPC; we are not adjusting recovery of the costs *of* the meters themselves, only the return *on* these assets.
[322] Uses the 13-month average balance per Chang Direct, Exhibit OPC Data Request 13 (Item No.: OPCDR13-01). BGE opposed OPC's position on this issue, but did not dispute the figure that OPC discussed in both written and oral testimony for the unamortized balance. We recognize that this figure might be reduced for ADIT, however, since BGE did not provide that information, the unamortized 13-month balance will be deducted from rate base in order to disallow a return *on* this asset.
[323] Butts Rebuttal at 22.

DOD recommended disallowing the smart grid O&M expenses in the test year because smart grid O&M expenses exceed O&M savings for that same period. As set forth above, we accept, as OPC and others did, the Company's methodology of a 10-year projection of costs and benefits. Based on this approach, smart grid O&M expenses are not expected to exceed O&M savings over the long run. The Commission did not, as part of Case No. 9208, require that smart grid O&M savings exceed O&M expenses for any one year. Moreover, the Commission's prior Order contemplated that the cost-benefit analysis would take into account market-side benefits in addition to operational savings.[324]

DOD also recommended an adjustment based on the effect of smart grid deployment on working capital. BGE testified that there are benefits to smart grid beyond those presented in this case, benefits yet to be fully developed and realized. We agree that BGE should investigate whether smart grid technology can optimize billing as Mr. Shpigler believes, in order to reduce working cash capital needs going forward.[325] We direct BGE to submit a report within sixty (60) days outlining the Company's findings and invite other parties to comment on that report within thirty (30) days of its submission.

Lastly, DOD recommended adjustments based on the "gross-up" conversion factor. While Mr. Shpigler's adjustment was based on an unsupported claim that industry experience is that smart grid reduces uncollectible accounts by more than 50%, BGE did compute a benefit associated with a reduction in uncollectible write offs, a benefit that

[324] *See, e.g.* Order No. 83531 at 46-47.
[325] For purposes of this case, cash working capital is based on the test year and BGE's current billing practices, so no adjustment is warranted.

appears to increase every year after deployment.[326] Thus, the uncollectible rate utilized in this case, based on actual test year data, is likely to decrease during the rate effective period. Therefore, we direct BGE, in its next rate case, to support its computed benefit for reduction in uncollectible write offs in future years with actual data, which should reflect a reduction in the uncollectible rate as compared to the actual uncollectible rate utilized in this case. And since BGE has projected the benefit associated with a reduction in write-offs for uncollectible accounts, we think it is appropriate for BGE to compute a projected uncollectible rate for the rate-effective period for our consideration. We will then make a finding as to whether an appropriate "gross-up" conversion factor should be used. In the interim, we reject DOD's proposed adjustment as not fully supported.

f. *Disallowed Costs*

The result of disallowing $16.6 million in costs that the Company incurred and attributed to the opt-out proceedings and resulting Commission decisions is, for electric, a rate base reduction of $3,549,000 and an operating income adjustment of $710,000.[327] For gas, there will be a rate base reduction of $1,401,000 and an operating income adjustment of $280,000.[328]

[326] Reduction in uncollectible write offs is one of the operational savings benefits; according to BGE, the operational savings benefits will continue to increase in value every year through 2025.
[327] This calculation uses the average balance of the smart grid regulatory asset, net of taxes, and assuming 71.7% attributable to electric per Vahos Supplemental Direct, Exhibit DMV-6 Actual Deferred Smart Grid Costs. We find it is appropriate to disallow this amount in costs incurred during the test period given Mr. Butts' reference to Order No. 86727, which was issued on November 25, 2014. *See* Butts Direct at 25.
[328] Assumes 28.3% attributable to gas per Vahos Supplemental Direct, Exhibit DMV-6 Actual Deferred Smart Grid Costs.

2. ***Baltimore City Conduit Fees (OIA 28, 29, 30; RBA 7, 8)***

The City of Baltimore ("City") owns and maintains an underground conduit system that contains utility-related equipment and cables.[329] BGE is the largest user of the conduit system and occupies approximately 12.4 million linear feet of conduit space.[330] BGE electric assets in the conduit system include electric cables, switches, transformers, street lighting cable, and communication cable.[331] All users of the conduit system, including BGE, pay to the City on a semi-annual basis a lease and maintenance fee based upon linear feet of occupancy.[332] The Baltimore City Board of Estimates approved an increase in the fees for all users from $0.9785 per linear foot to $3.33 per linear foot, effective November 1, 2015.[333] BGE's position is that the City is only permitted to charge a fee to BGE that is reasonably related to the actual expenses incurred by the City in maintaining the conduit system.[334] On October 16, 2015, BGE brought suit against the City to prevent improper use by the City of the conduit fee revenues and to place constraints on the City's ability to set the conduit fee in the future.[335]

BGE asserts that operating Income Adjustment 28 reflects a known and measurable increase in costs during the rate-effective period, as compared to the level of conduit expenses in the test year.[336] Operating Income Adjustment 29 provides for amortization over five years for the expenses related to the conduit rate increase during

[329] Vahos Direct at 16.
[330] Vahos Direct at 17.
[331] Vahos Direct at 17.
[332] Vahos Direct at 17.
[333] Vahos Direct at 17.
[334] Vahos Direct at 18.
[335] Vahos Direct at 18.
[336] Vahos Direct at 19.

the 7-month period between the effective date of the conduit increase on November 1, 2015 and the rate-effective period commencing in early June 2016.[337] Rate Base Adjustment 7 establishes a regulatory asset for the $15.4 million net increase in Baltimore City conduit fees incurred during the 7-month period between the effective date of the conduit rate increase on November 1, 2015 and the rate-effective period commencing in early June 2016.[338] These adjustments show the effect of treating the conduit fee increase as a base rate item.[339] Operating Income Adjustment 30 and Rate Base Adjustment 8 eliminate the impacts of Operating Income Adjustments 28 and 29 as well as Rate Base Adjustment 7 should the conduit fee increase instead be recovered through a rider as proposed by BGE. BGE proposed two versions of this rider: Option A would apply the charge only to customers who live in Baltimore City; Option B would apply the charge to all electric distribution customers regardless of jurisdiction.[340]

Party Positions

BGE

BGE believes that it is most appropriate to recover the incremental conduit fees through a rider.[341] A rider ensures that if adjustments are made to the fees as a result of the pending litigation or other reasons, customers will pay only the actual costs of maintaining the conduit system.[342] In his supplemental direct testimony, BGE witness Vahos provided an update on the status of the pending litigation. Mr. Vahos noted that

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[337] Vahos Direct at 20. We note that the test period in this case ended November 30, 2015, however, the Company treats the entire conduit fee increase as a post-test year event; apparently because the Company disputed the amount invoiced by Baltimore City, the Company did not accrue this expense on its books during the test year.
[338] Vahos Direct at 20.
[339] Vahos Direct at 20.
[340] Prepared Direct Testimony of John C. Frain, November 6, 2015 (“Frain Direct”) at 3.
[341] Direct Testimony of Mark D. Case, November 6, 2015 (“Case Direct”) at 29.
[342] Case Direct at 29.

the Circuit Court recognized that the parties' current contract requires an annual "true-up" of revenues and expenses to ensure that BGE only pays its pro rata share of the actual costs incurred by the City to operate and maintain the underground conduit system.[343] Mr. Vahos claims that the Circuit Court's recognition of the required "true-up" process further supports the need for a rider because the rider mechanism will ensure that customers receive the benefit of any funds returned to BGE as a result of the "true-up."[344]

On surrebuttal, Mr. Vahos responded to MEG witness Baudino's position that the Commission should disallow recovery of the increase in conduit fees during the November 2016-June 2016 time period, contending that BGE has met the standard for recovery of these post-test year costs as known, measurable and significant costs.[345]

City of Baltimore

Three witnesses submitted written testimony on behalf of the Mayor and City Council of Baltimore (the "City"). Mr. William M. Johnson, Director of the Baltimore City Department of Transportation ("DOT") testified that the parties are still operating in part under a 2008 Agreement in Principle which includes the concept of a "true-up" mechanism, however, Mr. Johnson testified that the true-up process was not clearly developed.[346] Mr. Johnson testified that in 2015, the DOT assessed its operations for conduit maintenance and concluded that a more proactive and preventative maintenance program was required for the conduit system instead of the "reactive" manner in which it historically conducted maintenance on the conduit system, making repairs as problems

[343] Prepared Supplemental Direct Testimony of David M. Vahos, January 5, 2016 ("Vahos Supplemental Direct") at 12.
[344] Vahos Supplemental Direct at 12.
[345] Vahos Surrebuttal at 9.
[346] Direct Testimony of William M. Johnson ("Johnson Direct") at 6.

arose.[347] Mr. Johnson testified that the City does not intend to use revenues from the conduit lease fees for city services and programs other than those related to operation and maintenance of the conduit system.[348] Mr. Johnson testified that the $3.33 per linear foot rate was developed based on the professional judgment of the DOT concerning the level of maintenance required by the aging conduit system.[349]

Lindsay M. Wines, Deputy Director of Administration for the City DOT also testified on behalf of the City. Ms. Wines testified that in addition to operating maintenance costs, the conduit lease fee was calculated to incorporate capital maintenance projects such as replacement of aged conduit system manhole covers and street restoration necessitated by conduit system repairs.[350] The $3.33 conduit lease fee also includes an annual amount for an emergency reserve and overhead (overhead costs include expenses incurred by other City agencies such as Legal, Fiscal, Contract Administration, and Human Resources).[351]

Ms. Wines testified that all revenue generated by the conduit lease fees charged to entities using the City's conduit system is accounted for separately in the City's Conduit Enterprise Fund ("Conduit Fund") which is audited annually by the City's Department of Audits and KPMG, LLP.[352] Ms. Wines explained that amounts are only transferred from the Conduit Fund to the City's General Fund so that appropriate amounts can be allocated to the budgets of the various departments or agencies supporting the operation of the

[347] Johnson Direct at 6-7.
[348] Johnson Direct at 13.
[349] Johnson Direct at 14.
[350] Direct Testimony of Lindsay M. Wines ("Wines Direct") at 7.
[351] Wines Direct at 7-8.
[352] Wines Direct at 11.

conduit system and the administration of the Conduit Fund.[353] Ms. Vines also testified as to how the true-up process has operated since 2008, stating that BGE has implemented the true-up by reducing its second semi-annual conduit lease payment each fiscal year by a true-up payment estimated by BGE for the prior fiscal year, and then performing a reconciliation based on the City's Comprehensive Annual Financial Report ("CAFR") once it is released.[354]

Dale A. Kessinger addressed cost allocation issues related to the recovery of the conduit lease fees.

OPC

Jonathan Wallach testified on behalf of OPC with regard to the recovery of increased Baltimore City conduit fees. Given the unique circumstances in this case, specifically uncertainty with regard to the outcome of litigation, OPC witness Wallach found the Company's proposal to recover incremental conduit fees through a separate surcharge reasonable.[355] Mr. Wallach states, however, that BGE has not offered any justification for why exceptional treatment of conduit fees should continue once litigation has been finally resolved, and that instead surcharge recovery should be temporary.[356] Noting that the Company currently recovers conduit fees from all ratepayers, Mr. Wallach opined that it is not reasonable to recover the increased conduit fees solely from Baltimore City ratepayers.[357] On rebuttal, Mr. Wallach added that if the fee increase is recovered from all ratepayers through BGE's proposed surcharge mechanism, then all

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[353] Wines Direct at 13.
[354] Wines Direct at 14.
[355] Direct Testimony of Jonathan Wallach, February 8, 2016 ("Wallach Direct").
[356] Wallach Direct at 21.
[357] Wallach Direct at 21-22.

ratepayers would be held harmless regardless of an eventual court ruling through the surcharge true-up mechanism.[358]

Department of Defense

DOD witness Dennis Goins recommended that because the Commission has a responsibility to protect ratepayers from paying rates to recover costs that BGE cannot demonstrate are just and reasonable, the Commission reject BGE's electric Rider 5 as proposed.[359] Instead, Dr. Goins recommended that the Commission require BGE to treat incremental City conduit fees as a deferred expense until the ongoing conduit fee litigation between BGE and the City is resolved (including a determination of appropriate conduit charges and terms of service).[360] Under his recommended approach, once the litigation is resolved, the Commission can then adjust the accumulated deferred expense (including a reasonable carrying charge) to reflect conduit rate adjustments (if any) resulting from the litigation and BGE can then be allowed to recover the deferred expense as well as future conduit fees using a Commission-approved rate recovery mechanism.[361]

Maryland Energy Group

MEG witness Richard Baudino recommended that the Commission disallow the Company's request to collect $18.97 million of increased Baltimore City conduit fees during the period of November 2015 through June 2016.[362] In his opinion, BGE is attempting to overcome the normal operation of regulatory lag for one isolated expense

[358] Rebuttal Testimony of Jonathan Wallach, March 4, 2016 ("Wallach Rebuttal") at 3.
[359] Direct Testimony of Dennis W. Goins, Ph.D., February 8, 2016 ("Goins Direct") at 8-10.
[360] Goins Direct at 10.
[361] Goins Direct, p 10.
[362] Direct Testimony and Exhibits of Richard A. Baudino, February 8, 2016 ("Baudino Direct") at 3.

item, which is inappropriate.[363] Mr. Baudino explained that revenues and expenses should be measured and annualized for known and measurable changes within the test year, so with respect to the increased conduit fees BGE should be allowed to collect the annualized difference between the existing level of conduit fees in base rates and the higher level of these fees that began on November 1, 2015 since it was still within BGE's test period.[364] However, Mr. Baudino stated that BGE should only be allowed to collect the increased conduit fees when new rates become effective in this case.[365] He further stated that BGE should not be allowed to pick and choose one of its cost elements that increased during the test year and then try to collect this increase before rates become effective later this year, either through a rider or regulatory deferral.[366] Mr. Baudino pointed out that BGE should be able to keep any refund from the City of excessive fees within the 7-month period of November 2015 through June 2016.[367]

Staff

Staff witness Patricia M. Stinnette discussed the prudency of the Company spending on City conduit charges and matters related to the accounting treatment of conduit-related monies. Staff witness Craig Taborsky discussed the engineering issues associated with the City's conduit. Staff witness Loubens Blaise discussed appropriate rate design for recovery of either total or partial conduit fees from ratepayers if the Commission chooses to accept the proposal to recover increased costs via a rider. Staff

[363] Baudino Direct at 12.
[364] Baudino Direct at 12-13.
[365] Baudino Direct at 13.
[366] Baudino Direct at 13.
[367] Baudino Direct at 14.

witness C. Shelley Norman, Ph.D, discussed the proposal to treat these costs as distinct from other Company-incurred costs, as well as the allocation of the costs.

Witness Stinnette explained that as an initial matter the conduit costs must be a prudent expense that provides used and useful service to customers.[368] Because the City wants to recover all of the costs of making capital improvements to its conduit before or during the year the costs are actually incurred, the accounting may not be appropriate or consistent with regulatory principles.[369] However, Ms. Stinnette went on to indicate her agreement with the period BGE used for the proposed rider if the costs are recoverable.[370] Ms. Stinnette recommended a CPI-U five year average of 1.82% instead of the proposed 2.75% for the July 2016 through June 2017 period.[371] Ms. Stinnette agrees with Option A for the rider noting that a similar mechanism is used for the Montgomery County Fuel Surcharge, applicable only to Montgomery County residents.[372]

Witness Craig Taborsky described the City conduit system, explained modes of failure of the conduit lines, and described some of the operational and maintenance issues associated with the underground conduit. Witness Taborsky indicated that BGE provided a confidential preliminary analysis estimating costs to enhance inspection, maintenance, and repair of the conduit which has significant differences in both the costs and method required for a proactive maintenance program.[373] Mr. Taborsky opined that the City studies for the proposed conduit work may not be specifically limited to the reliability,

[368] Corrected Direct Testimony and Exhibits of Patricia M. Stinnette, February 18, 2016 ("Stinnette Direct") at 8.
[369] Stinnette Direct at 8-9.
[370] Stinnette Direct at 9.
[371] Stinnette Direct at 10. CPI-U is CPI-Urban according to Ms. Stinnette's testimony at the hearing. Tr. at 1628.
[372] Stinnette Direct at 10.
[373] Direct Testimony of Craig Taborsky, February 8, 2016 ("Taborsky Direct") at 8.

safety, and maintenance of the system but rather include growth and enhancements.[374] Mr. Taborsky stated that if the system is being expanded to accommodate broadband networks, for example, then those customers should pay a greater share of the overall expense, because BGE customers should not be required to pay for work that is caused by and will benefit broadband customers and/or the City in general.[375] Mr. Tabosky concluded that the additional yearly charge of $30.7 million requires further justification before the cost can be flowed through to ratepayers in base rates; it must be shown to be prudently incurred.[376]

Staff witness C. Shelley Norman, Ph.D., explained that currently, the conduit rental fees are treated as other utility costs associated with maintenance of underground lines, and recovered from ratepayers throughout the utility service territory in base rates.[377] Dr. Norman noted that all other conduits within the BGE territory are owned and operated by the Company, with expenses recovered from ratepayers across the territory in distribution base rates.[378] Dr. Norman reviewed the pending litigation between BGE and the City and believes that the basis of the Company's complaint is that BGE does not believe that the City has demonstrated that the increased fees will be used solely for the operation and maintenance of the conduit.[379]

Dr. Norman explained that there are other bill amounts charged only to customers served in certain jurisdictions.[380] BGE recovers local taxes from ratepayers in Anne Arundel, Baltimore and Prince George's counties, and Baltimore City, as well as the

[374] Taborsky Direct at 9.
[375] Taborsky Direct at 9.
[376] Taborsky Direct at 9.
[377] Direct Testimony of C. Shelley Norman, Ph.D., February 8, 2016 ("Norman Direct") at 27.
[378] Norman Direct at 27.
[379] Norman Direct at 27.
[380] Norman Direct at 30.

Montgomery County Fuel Energy Tax surcharge.[381] Dr. Norman testified that these tax amounts are not specifically directed towards the provision of utility service in those jurisdictions.[382] She further testified that BGE does not charge geographically differentiated rates for any costs not designated as taxes.[383] She stated that in general, for reasons of equity and complexity, regulators do not typically analyze or require locational cost estimates within utility territory, instead differentiating rates by only territory-wide class characteristics.[384]

Although Dr. Norman could not find points of clear comparison in this jurisdiction or others, she stated that there are some previous policies and decisions to rely upon.[385] New service extensions or modifications may be charged to users requesting new investments.[386] More relevant, infrastructure requirements imposed on utilities by jurisdictions have in the past been deemed to be beyond those needed to provide quality service and have been thus excluded from recovery in rates.[387] The capital costs associated with undergrounding of utility equipment in parts of Annapolis was an issue in the 1980s. The work was characterized as "municipal" and deemed to have been to a substantial degree done for aesthetic reasons. Dr. Norman claimed recovery in base rates was found to be inequitable because the excess undergrounding costs would not provide substantial benefit to ratepayers generally, but rather primarily benefitted those residing in the historic areas where the relocation occurred. Dr. Norman noted a similar issue in the pending litigation - that improving the conduit for non-utility

[381] Norman Direct at 30.
[382] Norman Direct at 30.
[383] Norman Direct at 30.
[384] Norman Direct at 31.
[385] Norman Direct at 31.
[386] Norman Direct at 31.
[387] Norman Direct at 31.

purposes, in particular increased network infrastructure, has been considered the reason for spending on some sections of the conduit.[388] Dr. Norman stated that if spending on the conduit were not driven by utility needs, the inclusion of these costs in rates could lead to BGE customers being assessed a significant burden of costs associated with work they did not request, their electricity use did not cause a need for, they do not benefit from, and which may not be closely related to the service they receive.[389]

Dr. Norman testified that the utility equipment within the conduit system is part of a network operated and maintained by BGE for the benefit of the service territory.[390] She stated that while in general the equipment in City conduits serve City customers, some City customers are served by overhead lines and some customers outside of the City are served by circuits and equipment partially located within City conduits.[391]

Although the City and the Company agree that increased work needs to be done to maintain the conduit system to an acceptable standard, each has its own analysis of ways to enhance inspection, maintenance and repair activities.[392] Dr. Norman found that it is not clear from the data available which improvements considered by either party most improve the utility service received by ratepayers.[393] Dr. Norman noted that the existing true-up process utilized by the parties has not been sufficient to resolve disputes regarding whether or not expenses are truly related to conduit maintenance.[394] She concluded that the record does not allow her to make a clear determination regarding which amounts of the conduit lease fee increase might be related to the provision of

[388] Norman Direct at 33-34.
[389] Norman Direct at 34.
[390] Norman Direct at 35.
[391] Norman Direct at 35.
[392] Norman Direct at 35.
[393] Norman Direct at 36.
[394] Norman Direct at 38.

improvements desired by the City but are not necessary for maintenance of the conduit system adequate to meet BGE's needs.[395] Thus, she believes she must allow for the possibility that some portion of the requested rate increase is related to purposes extending beyond those of the provision of utility service.[396]

Dr. Norman stated that an interim solution to the situation of being required to make a determination regarding disputed third party costs which are currently being litigated in another venue is to include incremental costs in a rider.[397] She recommended a rider be allowed for customers within the City, with the Company being required to bring the matter before the Commission within thirty days of reaching an agreement with the City or of a decision in the pending litigation, as well as in any future rate cases that may occur prior to a full resolution of this issue.[398] She stated that any agreement between the Company and the City should detail responsibilities and methods for assessing needs, determining prioritization, locations and timing of work, accounting for capital and operational costs and an annual true-up process, managing shared space within the conduit system, and determining appropriate actions to improve and remediate conditions within the system to serve utility needs.[399] Dr. Norman noted that in accordance with long standing ratemaking principles, only costs determined to be reasonably and prudently incurred and directly related to the provision of utility service may be included in base rates applicable system-wide.[400]

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[395] Norman Direct at 39.
[396] Norman Direct at 39.
[397] Norman Direct at 40.
[398] Norman Direct at 40.
[399] Norman Direct at 40-41.
[400] Norman Direct at 41.

Dr. Norman stated that on an ongoing basis, recovery of costs for used and useful infrastructure in isolation is not consistent with regulatory best practices, but she believes the current situation presents an appropriate exception; thus she does not believe recovery of the conduit fees via a rider constitutes inappropriate single issue ratemaking.[401] Dr. Norman recommended that the Company be required to bring any requests to increase or decrease the rider rate, as a result of CPI adjustments, rate changes, late fees, an annual true-up, or any other reason, before the Commission for review and consideration.[402] Lastly, Dr. Norman recommended that the large amount proposed to be recovered in the first year of the rider should be mitigated by spreading recovery of the November 2015-June 2016 amounts over five years, as the Company proposed.[403]

On surrebuttal, Dr. Norman stated that Baltimore City witness Johnson mischaracterized her testimony regarding agreements or contracts between the City and the Company.[404] Dr. Norman does not intend for the Commission to dictate terms of any agreements between the City and BGE; rather the Commission may review any contracts or agreements entered into by the Company as part of its provision of regulated electric distribution services.[405] She requests that the Company be directed to bring any agreement with the City before the Commission, and report on how the various underlying disputes have been resolved, to aid the Commission in determining the appropriate allocation of conduit lease cost responsibility going forward.[406] She notes that Staff has a duty to recommend positions that protect customers from unjust and

[401] Norman Direct at 41.
[402] Norman Direct at 42.
[403] Norman Direct p. 42.
[404] Surrebuttal Testimony and Exhibits of C. Shelley Norman, Ph.D, March 21, 2016 ("Norman Surrebuttal") at 3.
[405] Norman Surrebuttal at 3.
[406] Norman Surrebuttal at 3.

unreasonable charges, which requires information about the nature and composition of any proposed charges, in order to ensure that the City is not taking advantage of its apparent monopoly power to unfairly assess charges that are socialized across the BGE service territory.[407] Absent such information and review, Dr. Norman recommends that costs be paid by those who, firstly, can hold decision makers accountable for their choices, and, secondly, will benefit from any improvements over and above those needed to support adequate and efficient provision of electrical distribution services.[408]

Dr. Norman notes that the Company has testified that it seeks a process, through the litigation, to monitor the City's expenditures.[409] Thus, Dr. Norman envisions a process by which conduit costs would be assigned to a Rider 5-A, where incremental costs are distributed locally to Baltimore City ratepayers unless and until they can be moved to socialization through a territory wide Rider 5-B.[410] This process would permit treatment of conduit lease costs incurred to provide adequate electric distribution services in a manner consistent with other necessary system expenses, while excluding "municipal project" costs from general rates.[411]

Testimony at Hearings

BGE

Mr. Vahos testified that while the Company supports the change from Baltimore City's reactive conduit maintenance program to a proactive maintenance program, the current litigation has to do with the scope and speed of the proposed proactive

[407] Norman Surrebuttal at 5-6.
[408] Norman Surrebuttal at 6.
[409] Norman Surrebuttal at 7.
[410] Norman Surrebuttal at 8.
[411] Norman Surrebuttal at 8.

maintenance program, and the City's commitment to actual costs of conduit maintenance only, and to perform true-ups.[412] Mr. Vahos testified that he proposed the alternative of the Company purchasing the City's conduit system.[413] According to Mr. Vahos' testimony, on December 18, 2015, BGE disbursed a payment in the amount of $4,875,448.28, the difference between the rate of $0.9785 per liner duct foot (that BGE had paid) and the amount the City had invoiced, which incorporated the increased rate beginning November 1, 2015.[414] Mr. Vahos testified that on March 23, 2016, BGE paid the City $18,987,785 on the second semi-annual invoice for fiscal year 2016, which incorporated a true-up of $1,825,366.76 for fiscal year 2015.[415] Mr. Vahos testified that historically the true-up is based on taking the City's independently audited financial statements and subtracting from the amount the Company paid the actual amount the City spent on the conduit system maintenance.[416] However, during the time period until BGE receives the audited financial statement, which can be two years, BGE uses an estimate based on past experience. Thus, the $1,825,366.76 true-up was based on the fact that the City spent roughly 30 percent below what the City charged BGE in prior years.[417] BGE's method for taking a true-up, which does not take into account monies reserved into the next fiscal year for an ongoing project, is one of the disputed issues in the litigation between the parties.[418]

Mr. Vahos testified that the Company is still proposing two options, Option A and Option B for Rider 5 for incremental conduit fees, though once the Company was able to

[412] Tr. at 615, *et seq*.
[413] Tr. at 617.
[414] Company Exhibit 22, Vahos Supplemental Direct at 12.
[415] Tr. at 627.
[416] Tr. at 629-630.
[417] Tr. at 630.
[418] Tr. at 635-640.

get two important concessions through the litigation in Circuit Court – that the increased conduit fees will only be used for actual costs of maintaining the conduit system and that there will be a true-up mechanism for returning amounts not spent – he now believes Option B is more reasonable.[419] However, Mr. Vahos also testified as to his doubt that the City could accelerate from a $15 million program to a $50 million program in one year,[420] and that there will come a time when the City does not need $50 million per year to maintain the conduit system, even on a proactive basis.[421] Mr. Vahos acknowledged that over the past 11 years, from 2004 when the rate was $0.27 per linear foot to 2015, when the rate was $0.98 per linear foot, the conduit fee increased approximately 365 percent, yet BGE never previously approached the Commission and proposed a rider to collect these fees.[422] He also acknowledged that the existing true-up mechanism is not specific as to timing, and that the audited financial statements that provide the basis for a fiscal year true-up come out as much as two years after the end of a fiscal year.[423] Mr. Vahos explained that because the Company does not have the audited financial statements, the Company estimates what the true-up will be for the fiscal year in question, and takes a credit against the second semi-annual bill from the City for the amount of that estimated true-up.[424] When BGE receives the audited financial statements, the estimated true-up is corrected to an actual true-up.[425] Mr. Vahos confirmed that the true-up only addresses the amount the City actually spent according to

[419] Tr. at 686-699.
[420] Tr. at 690-691.
[421] Tr. at 707.
[422] Tr. at 701-702.
[423] Tr. at 773.
[424] Tr. at 782.
[425] Tr. at 782.

its audited financial statements as compared to the amount BGE paid.[426] There is nothing in the current true-up mechanism that allows BGE to review for prudency the projects that the City has planned for the next year, or for a review of the projects that were completed in the prior year.[427] Lastly, if the credit that BGE takes off the second semi-annual invoice is not during a test year, that credit goes back to the Company, not ratepayers.[428]

With regard to the mediation that is to take place in the pending litigation between the City and the Company, BGE witness Case testified that the Company wants, as a result of the mediation, to obtain a level of comfort that the $3.33 per linear foot conduit fee is the proper charge based on the work the City is proposing.[429]

City of Baltimore

City witness Johnson testified about how the City's procurement process requires that the Department of Transportation have the "cash in hand" to fund a contract before it may execute that contract.[430] Mr. Johnson explained how the City encumbers the funds for a project.[431] Mr. Johnson agrees that there should be a process of reconciliation that takes place on a regular basis, but he does not agree that an annual true-up process makes sense because many projects cannot be completed in one year; he spoke of a three-year period.[432] Mr. Johnson confirmed that the $3.33 fee should decrease over time.[433] Mr. Johnson indicated that he has heard rumors but otherwise is unfamiliar with a plan on the

[426] Tr. at 782-786.
[427] Tr. at 820-828.
[428] Tr. at 862-863.
[429] Tr. at 1061.
[430] Tr. at 1149-1150.
[431] Tr. at 1151.
[432] Tr. at 1156-1163.
[433] Tr. at 1163-1165.

part of the City to use the underground conduit system for broadband purposes.[434] Mr. Johnson discussed the historical approach of these O&M costs being in base rates and stated that he does not understand why there would be a different approach of a surcharge simply because the fee is based on proactive maintenance as opposed to reactive maintenance.[435] Mr. Johnson testified that while it is possible all of the funds the City has received could become encumbered in this fiscal year, it is also possible that the City will still be in the process of executing the contracts that would encumber those funds into the next fiscal year.[436] Mr. Johnson explained that the City is trying to get to 12 to 15 percent of the conduit system each year, but may only have enough resources to complete between 10 and 12 percent, which is not enough to do all of the work that is identified but at least enough inspection resources to be able to perform an assessment of damages in order to re-prioritize the capital plan for future years.[437] Mr. Johnson stated that the City intends to bring in a program management firm to conduct much of the assessment of the conduit system.[438] He does not see the process of accountability with regard to the conduit fund to be any different than the City's routine process of accountability for all of the federal funds the City receives.[439]

Maryland Energy Group

On cross-examination by the Company with regard to his recommendation to disallow the Company's proposed recovery of increased conduit fees between November 2015 and June 2016, MEG witness Baudino explained that there is always a time period

[434] Tr. at 1186-1187.
[435] Tr. at 1190-1191.
[436] Tr. at 1224-1225.
[437] Tr. at 1228-1229.
[438] Tr. at 1223, 1250.
[439] Tr. at 1252-1253.

between the end of the test period and the rate-effective period during which the Commission adjudicates the case and decides what rates will be going forward, and that many things change between the end of a test period and the rate effective period – costs can go up or down and revenues can go up or down, but the Commission needs to be able to make its determination based on what is known as of the end of the test period.[440] Mr. Baudino testified that the conduit fee is a recurring cost, set at whatever level is determined to be reasonable, but that since it is ongoing, it is not extraordinary, and thus, in his opinion the Company should not be permitted to jump normal regulatory lag for this item.[441]

Staff

Staff witness Norman explained that Staff wants to investigate the City's proposed conduit maintenance program to determine whether or not the proposed level of spending is appropriate and necessary for the efficient and economical provision of reliable electrical distribution service. Option A for Rider 5 is proposed by Staff as an interim solution pending the development of an adequate review process.[442] Dr. Norman noted that Staff would not suggest what the City should do with regard to its conduit system; Staff would simply evaluate the conduit expense for inclusion in rates.[443] However, until the conduit maintenance costs can be examined for their prudency and for their appropriateness and for whether or not they are necessary to the efficient and economical operation and provision of reliable electric distribution service, it is Staff's

[440] Tr. at 1404.
[441] Tr. at 1407-1408.
[442] Tr. at 1688.
[443] Tr. at 1697.

position that they should be considered separately because they cannot be evaluated.[444] Staff's position that these costs be treated differently is based on the size of the increase in conduit fees that BGE has been assessed, and the fact that the costs are for work that has not yet been done, which typically gives rise to a higher level of scrutiny.[445]

Dr. Norman testified that once Staff has the information and can review the conduit fee expense in sufficient detail, Staff would support a move to socialization of the costs that are found to be appropriate and necessary for the reliable and efficient provision of electric distribution service.[446] Dr. Norman agreed that a hybrid approach with both Option A and Option B in place simultaneously might be less challenging under retroactive ratemaking constraints.[447] Dr. Norman conceded that under Option A, it is possible that City customers could pay for costs associated with the increased conduit fee that do not bear any relation to the provision of electric service, and that under Option B, customers outside of Baltimore City could pay costs related to Baltimore City projects and not related to the provision of anyone's electric service, neither of which are ideal outcomes.[448] Dr. Norman acknowledged that there is not much precedent for how to handle the situation of the City conduit fee, however, if the conduit system is being improved to a degree beyond that which is necessary, that is a decision the City would be making related to things other than electrical distribution services.[449] That is why, in her opinion, the costs of such work should be paid by those who can hold decision-makers

[444] Tr. at 1705.
[445] Tr. at 1706.
[446] Tr. at 1718.
[447] Tr. at 1724.
[448] Tr. at 1724-1725.
[449] Tr. at 1727.

accountable for their choices.[450] Alternatively, Dr. Norman agreed that the conduit fee could simply be part of the Company's regular O&M expense.[451] Dr. Norman testified that it is Staff's position that once there is a resolution regarding how the conduit maintenance work is to be evaluated, the conduit fee could move into base rates and remain there.[452]

Dr. Norman testified that, given the uncertainty surrounding the proper amount of the conduit fee, directing BGE to put the conduit fee expense into a regulatory asset would be an option, noting that a regulatory asset could become substantial in size if the matter was not resolved quickly.[453] Dr. Norman also confirmed that the Commission could disallow the cost.[454]

Commission Decision

We spent several days' worth of the hearings in this case embroiled in questioning and testimony related to the Baltimore City conduit system. BGE and the City are currently involved in litigation in which BGE's stated objectives are to develop a process in which it collaborates with the City on the size, scope and priorities of the City's proposed proactive maintenance plan and becomes comfortable that the newly increased conduit fee is appropriate to pass on to ratepayers. BGE's stated objectives comport with PUA §4-101, which provides that just and reasonable rates take into account only those expenses that are necessary and proper. The Court of Appeals of Maryland has described the Commission's ratemaking role as one of determining "what rates the utility should be

[450] Tr. at 1725-1729.
[451] Tr. at 1794.
[452] Tr. at 1794.
[453] Tr. at 1799-1801.
[454] Tr. at 1809.

allowed to charge in future years to cover prudent expenses…." *OPC v. Md. Pub. Serv. Comm.*, 355 Md. 1 (1999). Thus, the Commission must determine whether the expenses for which the Company seeks recovery in rates, including those associated with the Baltimore City conduit fee, are prudent.

In reviewing a utility company's expenses, we utilize a historical test year approach.[455] The test year in this case is the 12 months ending November 30, 2015. The Company has proposed several adjustments to the actual test year book data, including adjustments to operating income and rate base to reflect changes resulting from the increased Baltimore City conduit fee. Adjustments to the actual test year book data are made in order to develop the most likely set of financial conditions the utility will face during the rate effective period. However, these adjustments are typically for unusual events that occurred during the actual test year period, or for known and measurable changes that will occur within a given time period after the end of the test year.[456]

We disagree with the Company contention that Operating Income Adjustment 28 reflects a known and measurable increase in costs. Litigation between BGE and the City about the increased conduit fee is ongoing. Despite the parties' agreement on some general principles and attempts to mediate the dispute, BGE witness Vahos indicated that the litigation process could take years before it is fully resolved.[457] The parties disagree as to how the true-up process should work. We note that historically, BGE has been calculating an estimated true-up of thirty percent (30%) of the City's second semi-annual invoice. For the past few years, the City's actual annual spend was approximately 15%

[455] *See Bldg. Owners and Mngrs Ass'n v. Pub. Serv.Comm'n,* 93 Md.App. 741 (1992).
[456] *See, e.g.* Case No. 9326, Order No 86060 at 14-15; Case No. 9336, Order No. 86441 at 21.
[457] Tr. at 798.

less than the amount collected in conduit lease fees.[458] Company witnesses testified that they anticipate a large true-up associated with the new lease rate, given that the City cannot accelerate from its current spend of about $10 million per year to such a larger program of over $40 million in one year.[459] Indeed, there was testimony to indicate that the City is not very far along in its planning process for implementing its proactive maintenance program. Witness Johnson stated that the City was only just now obtaining approval to issue an RFP (request for proposal) for the program manager contract, under which an entity would perform the assessments of the conduit that the City needs before it can even begin to prioritize proactive maintenance work.[460] Then, according to BGE, there will come a time when the City does not need the amount of the increased fee per year to maintain the conduit system, even on a proactive basis. In addition, the elements of the increased conduit fee are also not yet known, such as the amount of the "emergency reserve fund" and "overhead" to be assigned to other City agencies. .

We recognize that no Party proposed disallowing the Company's proposed adjustment to recover increased conduit fees in the rate effective period.[461] The Parties, apparently in reaction to the Company's proposal, largely offered comments on whether they believed one version of a rider or another was reasonable. We are not bound by the proposals of the Parties in the case, however. We are guided by our statutory mandate

[458] We note that no party has objected to BGE continuing to collect in base rates the prior conduit lease fee of approximately $0.98 per linear foot, even though that amount has not been fully spent by the City in recent years.
[459] We are unpersuaded by BGE's argument that the increased conduit lease fee is known and measurable simply because the City has invoiced BGE and BGE is under an obligation to pay the City's invoice. It is uncontested that the net conduit fee amount – that is, the amount that will have been paid after the appropriate true-up – is not known, and even difficult to estimate, at this time.
[460] Tr. at 1174.
[461] We note that DOD recommended rejecting the rider but suggested placing the increased conduit fee amounts in a regulatory asset, which could allow recovery of those amounts in the future.

and sound regulatory principles. The Company proposed a rider mechanism for the very reason that the incremental conduit lease fee expense is not known and measurable. Applying sound regulatory principles, we will not allow an adjustment to the Company's test year expenses for an expense that is not known and measurable, and thus disallow proposed Operating Income Adjustment 28.

The Company also proposes to recover in rates the post-test year expenses for the 7-month period between the effective date of the conduit rate increase on November 1, 2015 and the rate-effective period commencing in early June 2016. We will disallow Operating Income Adjustment 29 and Rate Base Adjustment 7 because, for the reasons set forth above, the change in costs associated with the Baltimore City conduit fee are not known and measurable during this period,[462] and for the additional reason that BGE has not supported its request to overcome the normal operation of regulatory lag for this one isolated expense item. While the Commission has allowed post-test year adjustment for particular types of expenses, such as reliability expenses, such adjustments must be known and measurable as of the time of the hearings and are still exceptions to the historical test year approach. Here, the increased conduit fees are not known and measurable, and they are a basic operating expense that does not warrant an exception to the historical test year approach.

While it is not within the Commission's jurisdiction to determine the amount of the Baltimore City conduit lease fee, it is the within the Commission's jurisdiction – and

[462] Mr. Vahos testified that the City had not started the proactive maintenance program even as of the hearings in this case. Tr. at 785. Director Johnson testified that the RFP for project planning had not yet been issued. Therefore, we seriously doubt that much of the fee increase paid by BGE for this period will be spent during this period, meaning that most of the increased amount paid for this period should be returned in a true-up.

indeed, it is the Commission's responsibility to Maryland ratepayers – to ensure that just and reasonable rates include only those expenses that are necessary and proper. Our task with regard to the increased conduit lease fee is the same as with all expenses for which a utility seeks cost recovery – to determine whether the conduit lease fee expense, or a portion thereof, is reasonably related to the provision of safe and efficient electricity service such that it is appropriate for BGE to include the expense in rates, and if so, when and how any such amount should be apportioned among ratepayers. What we would like to see is for the City and BGE to negotiate a reasonable lease rate that as closely as possible reflects BGE's use of the City's conduit system on a going forward basis. Particularly because the City's stated purpose is to engage in a proactive maintenance program, we believe the City should be able to plan the necessary inspection and maintenance work to be performed and manage the amount of funds it receives for that maintenance work accordingly.

We understand that whatever rate the City and BGE might negotiate as fairly compensating the City for BGE's use of the City's conduit system might increase at a later date, for inflation or other reasons. However, we believe that there could be a set rate for a given period of time that would more closely resemble a typical operating expense, as opposed to an atypical expense that requires separate regulatory treatment. We are not suggesting that there not be a true-up; rather, we envision that the results of a true-up might be to adjust the conduit lease rate prospectively, if BGE and the City determine that the City is collecting too much revenue as compared to what it spends to proactively maintain the conduit, and thus has reserves beyond that which is necessary or reasonable.

When the Company elects to file its next base rate case, and the corresponding test year for the rate case, is up to BGE. The litigation (or mediation) between BGE and the City will be further along and potentially finalized by the time of the next rate case, and BGE will be able to provide conduit lease fee information based on a City-developed proactive conduit maintenance plan[463] such that the amount of the conduit fee expense is known and measurable. We will conduct a prudency determination at that time and BGE will need to be able to support the amount of the conduit lease fee that is reasonably related to the provision of safe and efficient electricity service and demonstrate that it properly reflects the ongoing cost of service. If the evidence shows that the City is charging BGE an excessive or inappropriate conduit fee, we will consider all options to ensure that all BGE ratepayers are not paying for non-utility expenses.[464]

3. ***OIA 2: Defer and Amortize Gains / Losses on Sale of Real Estate***

BGE witness Vahos testified that OIA 2 reflects the deferral of the August 2015 gain on the sale of real estate and the related amortization of the net gain in accordance with the FERC Uniform System of Accounts. BGE realized a gain of $1,007,000 on real estate sold in 2015. The Company proposed to amortize the net gain of the sale of real

[463] We believe that given BGE's technical capabilities and its knowledge of the conduit system, it is appropriate for BGE to seek to play a collaborative role throughout the program's planning and implementation.

[464] Use of a rider could potentially allow charges above and beyond those found to be reasonably related to the provision of safe and efficient electricity service to be assigned to City residents if such charges are found to represent an "excess investment". *See Re Baltimore Gas and Electric Company*, 80 MD PSC 112, Case No. 8127, Order No. 68240 (1989), *citing* Order No. 56351 (1966) in which the Commission adopted the following policy: "Whenever electric utilities in the State are required by local zoning, ordinance or by other exercise of the police power of a local subdivision to construct an electric line underground at a cost substantially higher than the cost to construct the same line overhead using acceptable standards of utility line construction, then in the absence of the proof of unusual circumstances, and [sic] annual fixed charges needed to support the excess investment shall be imposed on all of the utility's customers receiving service *in the geographic area and/or the local subdivision to which the regulation or ordinance is applicable as a whole.*"

estate during the test year over a two-year period, pursuant to Commission Case No. 7695.[465]

OPC witness Effron opposed BGE's proposed adjustment. Mr. Effron observed that BGE reflected only three months of annual amortization because the gain began on September 1, 2015, when there were only three months remaining in the test year.[466] Mr. Effron testified that because BGE will be amortizing the gain annually going forward from the test year, the pro forma operating income should reflect annual amortization of the full gain.[467] Accordingly, Mr. Effron recommended an annual amortization of $504,000 (representing an increase of $378,000 above the amortization of $126,000 reflected by BGE), resulting in an increase in the electric after-tax net operating income of $225,000.[468]

On rebuttal, Mr. Vahos testified that BGE's adjustment is consistent with Commission precedent that the amortization of deferred gains and losses included in operating income be amortized over 24 months commencing on the effective date of the gain/loss.[469] Mr. Vahos noted that in previous rate cases, it consistently applied the same amortization schedule to real estate sales, irrespective of when the 24-month amortization happened to commence, and that changing that methodology as Mr. Effron suggested would be tantamount to changing Commission practice.[470] OPC replied that Mr. Effron's

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[465] Vahos Direct at 44. In companion RBA 5, the Company reflects the unamortized gain on real estate which is being amortized into operating income for ratemaking purposes over a two year period. *Id*. at 56.
[466] Effron Direct at 14.
[467] Effron Direct at 15, Effron Surrebuttal at 15.
[468] Effron Direct at 15.
[469] Vahos Rebuttal at 39, citing PSC Order Nos. 70476, 80460, 83907, and 85374.
[470] Vahos Rebuttal at 39.

adjustment is consistent with the numerous annualization adjustments that the Company has proposed.[471]

Commission Decision

We decline to accept Mr. Effron's recommendation to amend BGE's adjustment to reflect annual amortization of the full gain from the sale of real estate. We find (and OPC does not appear to dispute) that BGE's adjustment is consistent with Commission precedent that the amortization of deferred gains and losses included in operating income be amortized over 24 months *commencing on the effective date of the gain/loss*. BGE has followed this practice and we have approved it through various rate cases, including those cited by BGE above. *See also* Case No. 7695, Order No. 66273, *Baltimore Gas and Electric Co.*, 74 Md. PSC 249, 265 (July 1, 1983). Mr. Effron's adjustment would require a change in Commission practice, which we decline to require at this time. We note that if we did change Commission practice in this case, when utilities filed adjustments that involved real estate *losses*, the ratepayers would be disadvantaged by Mr. Effron's adjustment. Accordingly, we accept BGE's Operating Income Adjustment 2 as filed resulting in an operating income reduction of $526,000 for BGE's electric operations.

4. *OIA 8: Annualize Certain Regulatory Asset Amortization Periods Revised in Case No. 9355*

In Order No. 86757, the Commission accepted the unanimous settlement agreement in Case No. 9355, involving BGE's 2014 application for a rate increase.[472]

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[471] OPC Initial Brief at 47.

Part of that settlement included the continued amortization of certain generation-related regulatory assets from the 1999 Restructuring Settlement in Case Nos. 8794/8804.[473]

In OIA 8, BGE adjusted the amortization expense to reflect the full annual effect of the revision to the amortization schedule for Case No. 8794/8804 regulatory assets agreed to by the parties in Case No. 9355. That revision affected the amortization of Case No. 8794/8804 regulatory assets included in rate base.

OPC witness Effron testified that the Case No. 8794/8804 regulatory assets not in rate base are now nearing the end of their recovery period.[474] He calculated that by May 31, 2016, the remaining balance of the Case No. 8794/8804 regulatory assets not in rate base will be $14.8 million, and that the amortization of that balance will be complete by the end of year 2017. Mr. Effron observed that if the rates established in this case are in effect beyond the end of 2017, when recovery is complete, then BGE will over-recover costs. He therefore recommended that the remaining Case No. 8794/8804 regulatory assets not in rate base as of May 31, 2016 be amortized over three years, consistent with how the rate case expenses associated with the present rate case are treated in OIA 20. Mr. Effron's recommendation would result in a reduction to the annual amortization expense of $4,314,000 and an increase to pro forma electric operating income of $2,573,000.[475]

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[472] Case No. 9355, *In The Matter Of The Application Of Baltimore Gas And Electric Company For Adjustments To Its Electric And Gas Base Rates.*
[473] The referenced cases addressed rates and other issues related to BGE's electric restructuring. Case No. 8794, *In the Matter of BGE's Proposed (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates* and Case No. 8804, *In the Matter of the Petition of People's Counsel for a Reduction in the Rates and Charges of BGE*, 90 MD PSC 197 (1999).
[474] Effron Direct at 18-19.
[475] Effron Direct at 19.

Mr. Vahos opposed Mr. Effron's recommended adjustment. He observed that OPC was a signatory to the settlement agreements discussed above. He further asserted that "[s]ince this asset is not in rate base, the Company is undeniably harmed relative to the terms of the restructuring settlement agreement."[476]

Commission Decision

We accept BGE's Operating Income Adjustment 8, which adjusts the amortization expense to reflect the full annual effect of the revisions to the amortization schedules in Case No. 8794/8804 regulatory assets, which were in turn agreed to by the parties in Case No. 9355. Although Mr. Effron makes an important point that the assets may be fully amortized by the end of year 2017, we note that that date is more than a year and a half from the beginning of the rate effective period in June 2016. Given BGE's predilection for filing rate cases nearly annually, we find OPC's recommendation unnecessary.[477] Additionally, we find persuasive Mr. Vahos' testimony that the amortization schedules were previously agreed to in settlements. Accordingly, we accept BGE's adjustment. This results in an operating income adjustment of $177,000 for BGE's electric operations.

5. *OIA 13: Annualize Allowance for Funds Used During Construction to Reflect Requested Returns*

In OIA 13, BGE witness Vahos annualizes the allowance for funds used during construction ("AFUDC") included in unadjusted operating income at the 7.46% electric rate of return and 7.41% gas rate of return agreed to in the Case No. 9355 settlement

[476] Vahos Rebuttal at 38.
[477] Additionally, the Commission's Staff will track any over recovery of assets and the Commission will determine the appropriate treatment of any such over recovery in BGE's next rate case.

agreement, to reflect a level that is consistent with the 7.74% and 7.69% rates of return for electric and gas, respectively, that are supported by BGE.[478] Staff witness Poberesky adjusted AFUDC to reflect Staff's proposed weighted cost of capital.[479]

No party disputed BGE's methodology for making the adjustment, however, OIA 13 is impacted by other adjustments that have been contested. Pursuant to the other decisions that have been made in this Order, OIA 13 as revised results in an operating income reduction of $92,000 for BGE's electric operations and an operating income reduction of $81,000 for BGE's gas operations.

6. ***OIA 19: Annualize CVR Costs Since Case No. 9355***

Maryland's electric utilities are required by Commission regulations to delivery electric distribution service to their customers within certain voltage parameters.[480] However, customers at the higher end of the voltage band tend to consume more energy than customers at the lower end.[481] BGE's Conservation Voltage Reduction ("CVR") program lowers overall electric consumption by reducing the voltage delivered to appliances such as air conditioners, without negatively affecting their functionality.[482]

BGE witness Vahos testified that pursuant to Commission Order No. 84756 in Case No. 9153, the Company has been deferring O&M expenses, depreciation expense, property taxes and return associated with its CVR program[483] into a regulatory asset and

[478] Vahos Direct at 46.
[479] Poberesky Direct at 5.
[480] *See* COMAR 20.50.07.02.
[481] Tr. at 37.
[482] Tr. at 37 (Butts).
[483] BGE's CVR program reduces electric consumption by reducing the voltage delivered to appliances such as air conditioners, without negatively affecting their functionality. *See* Hearing Transcript at 36 (Butts).

amortizing the regulatory asset over two years upon approval in a base rate case.[484] Mr. Vahos testified that BGE followed (and the Commission approved) that practice in Case Nos. 9299 and 9326. In the present proceeding, OIA 19 recovers the amortization of the CVR costs incurred subsequent to August 2014 (the end of the test year in Case No. 9355) through the end of the test year in this proceeding (November 2015) over a two-year period. This adjustment also provides for the reversal of certain CVR-related deferrals (*i.e*. depreciation, property taxes, and returns) in the test year in order to recover ongoing expenses and return.[485]

OPC witness Effron recommended that OIA 19 be modified. He observed that the revenue requirement in Case No. 9355 included approximately $1.1 million of CVR costs and that amortization of $547,000 per year commenced in December 2014.[486] He further noted that at the start of the rate effective period, the remaining balance to be amortized will be only $274,000. He concluded that if the rates established in this case are in effect for more than six months, BGE will over-recover the CVR costs authorized for recovery in Case No. 9355.[487] He therefore recommended that the costs remaining at the start of the rate effective period be amortized over two years, which would result in annual amortization of $137,000 in lieu of the $547,000 proposed by BGE.[488]

In response, Mr. Vahos observed that BGE already eliminated the amortization of deferred costs that were completed in the test year through OIA 9 (a point that OPC does not contest). However he argued that it would be inappropriate to extend the two-year

[484] Vahos Direct at 51.
[485] Vahos Direct at 48.
[486] Effron Direct at 16.
[487] Tr. at 1567.
[488] Effron Direct at 16-17.

amortization period for remaining CVR costs through a re-set of the two-year amortization period commencing on May 2016, as proposed by Mr. Effron.[489] Mr. Vahos further argued that Mr. Effron's recommended treatment of CVR costs would be inconsistent with the Commission-accepted amortization period in previous proceedings.

Mr. Effron rejoined that BGE has offered no other mechanism to avoid the over-recovery of CVR costs that he has testified could occur pursuant to OIA 19.[490]

Commission Decision

We agree with Mr. Effron that BGE's proposed adjustment carry's a very high probability of over recovery of certain CVR costs. Case No. 9355 included about $1.1 million of CVR costs that commenced amortization at a rate of $547,000 per year beginning in December 2014. Only $274,000 of unamortized assets will remain at the start of the rate effective period. As Mr. Effron testified, if BGE declines to file a new rate case for more than six months after the beginning of the rate effective period, the Company will over recover. Accordingly, we adopt OPC's recommendation to modify Operating Income Adjustment 19 by amortizing the costs remaining at the start of the rate effective period over two years. That modification results in annual amortization of $137,000 in lieu of the $547,000 proposed by BGE. Our decision results in an operating income reduction of $1,040,000 for BGE's electric operations.

[489] Vahos Rebuttal at 38.
[490] Effron Surrebuttal at 15.

7. *OIA 21: Recover Exelon Business Service Company Compensation in OIA 11*

BGE Position

In Order No. 86060 in Case No. 9326, the Commission disallowed a portion of the related costs for long term incentive compensation plans "on the basis that the plans failed to clearly show a nexus between the plans' metrics and ratepayer value."[491] In that Order the Commission required that prior to a future rate filing, the Company should be prepared to "to demonstrate the extent to which incentive compensation plans include operational metrics related to BGE, and how such metrics deliver value to BGE ratepayers."[492] In this proceeding, BGE proposed uncontested Operating Income Adjustment 11, which reflects compliance with the Commission's decision in Case No. 9326 in Order No. 86060 where the Commission "authorize(d) BGE to recover 50% of its Restricted Stock plan and only 40% of its LTIP costs related to the Performance Share and One Time Bridge Award."[493] For those programs that have not changed[494], witness Vahos testified that through OIA 11, BGE is excluding BGE and Exelon Business Services Company ("BSC") long-term compensation costs at the same percentages disallowed by the Commission in Case No. 9326.[495]

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[491] Vahos Direct at 30.
[492] *Re Baltimore Gas and Electric Company,* 104 MD PSC 653, 681 (2013)..
[493] Poberesky Direct at 4.
[494] Vahos Direct at 31 explained that Case 9326 BGE's long term incentive compensation programs were" (1) Restricted Stock and (2) Performance Share program. Beginning in 2014, BGE took steps to better align its long term incentive compensation plans with operational performance. In 2014, for Key Managers and Vice Presidents, BGE replaced the long term incentive compensation programs considered by the Commission in Case No. 9326 with two new programs: (1)the Long Term Performance Program ("LTPP") and the Long Term Cash Award Program ("LTPCA").
[495] Vahos Direct at 30.

Mr. Vahos argued, however, that because the services provided by Exelon BSC are no different than services provided by unaffiliated third party vendors, the Commission should reconsider its prior decision to disallow a portion of the costs allocated to BGE associated with Exelon BSC's long-term incentive compensation programs.[496] Mr. Vahos argued that BGE should be allowed to fully recover the costs of long term incentive compensation because these "costs are only one of many costs that Exelon BSC incorporates into what it charges BGE and other Exelon companies for the range of shared services that Exelon BSC provides."[497] And the same would be true of any third party vendor providing these services to the Company, according to Mr. Vahos. "In other words, the cost of employee compensation would be included with all other costs of operating the business in the prices charged to BGE for the vendor's services, in addition to the profit margin," which Exelon BSC does not charge BGE.[498] BGE's proposed OIA 21 would permit recovery of the costs of Restricted Stock and Performance Share Award programs for Exelon BSC employees.[499] With OIA 21, the Company seeks to recover $2.7 million of the compensation associated with Exelon BSC long-term incentive plans.[500]

Staff Position

Staff witness Yulia Poberesky recommended that the Commission reject BGE's OIA 21 for several reasons. First, in Order No. 86060, the Commission did not differentiate the authorized portion of Restricted Stock plan and Performance Share

[496] Vahos Direct at 30-31
[497] Vahos Direct at 33.
[498] Vahos Direct at 34.
[499] Vahos Direct at 35.
[500] Vahos Direct at 35.

expenses applicable to BGE employees and Exelon BSC employees. The same adjustment percentages should be used for BGE employees and Exelon BSC employees, as BGE did with OIA 11.[501] Ms. Poberesky also noted that "BGE did not provide clear evidence, via analysis or other support, showing a cost benefit to BGE customers by using Exelon BSC employees, as opposed to using a vendor… to warrant this adjustment."[502] Thus, Staff recommended disallowing BGE OIA 21.

OPC Position

OPC witness Effron testified that the real issue "is not whether Exelon can pay its employees the incentive compensation that it deems appropriate, but rather the extent to which such incentive compensation should be recoverable from ratepayers."[503] Mr. Effron recommended that the Commission reject OIA 21 because Exelon has not made the necessary showing for the inclusion of this expense in its revenue requirement.[504]

Commission Decision

Based on the foregoing, we do not find that BGE has provided the necessary support for us to reconsider our decision in Order No. 86060. Therefore, we accept the recommendation of Staff and OPC, and disallow BGE Operating Income Adjustment 21.

8. *OIA 34: Tax Impact on Interest Synchronization*

Interest synchronization refers to the procedure whereby the interest deduction used for Federal income tax treatment is synchronized with the interest component of the return on rate base to be recovered from ratepayers. The interest deduction is calculated

[501] Poberesky Direct at 5.
[502] Poberesky Direct at 5.
[503] Effron Direct at 13.
[504] OPC Initial Brief at 46.

by multiplying the rate base by the weighted cost of debt.[505] The resulting interest is then multiplied by the State and federal income tax rates to arrive at the operating income adjustment. In this case, the parties do not contest that an interest synchronization adjustment is necessary to reflect the tax effect of pro forma interest. Furthermore, the calculation is uncontested as to methodology. Therefore, using a capital structure including a 51.9 percent equity ratio, as determined herein, we find that the appropriate interest synchronization results in an electric operating income reduction of $2,177,000 and a gas operating income adjustment of $18,000.

9. ***RBA 9: Cash Working Capital***

Cash working capital ("CWC") represents the amount of investor supplied cash a company requires in order to provide the funds necessary to operate the business on a day to day basis.[506] The amount of CWC required is determined by a lead/lag study, which measures the difference between the company's revenue lag and its expense lag. The revenue lag measures the average number of days from the date service is rendered to the date payment for such service is received. The expense lag represents the number of days from the incurrence of an expense to the date the company pays the expense. Once the revenue and expense lags are determined, the CWC requirement is calculated by applying the net lag to the average daily amount of operating expense.[507]

BGE witness Vahos presented the Company's requirements regarding CWC based on BGE's most recent Lead/Lag Study on 2014 actual payments and revenue

[505] Effron Direct at 25-26.
[506] Vahos Direct at 59.
[507] Poberesky Direct at 3.

collections.[508] The results of the Study are presented in BGE Exhibit DMV-8. Mr. Vahos calculated, for example, a revenue lag of 47.0 days.[509] He also determined expense lags for numerous categories of expenses. The parties do not contest BGE's methodology for determining CWC. However, CWC is affected by other operating income adjustments being contested.

Based on the Commission's determinations in the other sections of this Order, BGE's CWC requirement will be decreased in the amount of $4,466,000 for the Company's electric operations and decreased in the amount of $218,000 for its gas operations.

10. ***Accumulated Deferred Income Taxes - Bonus Depreciation***

The Protecting Americans from Tax Hikes Act of 2015 ("PATH Act") extends 50% bonus depreciation on Accumulated Deferred Income Taxes ("ADIT") through the year 2017.[510] It allows taxpayers to take immediate income tax deductions for 50% of qualifying plant additions.[511] Although the Act was not signed into law until December 18, 2015, it expressly provides for retroactive effect to January 1, 2015.

OPC witness Effron observed that BGE reflected the impact of the extension of bonus depreciation for 2015 and 2016 on ADIT offsets to pro forma plant additions in

[508] Vahos Direct at 63.
[509] Vahos Direct at 64.
[510] Tr. at 725-26. OPC witness Effron described ADIT as the "cumulative effect of taxable temporary differences." Effron Direct at 3. ADIT results from differences in the rates at which an asset is depreciated for tax versus ratemaking purposes. For example, BGE may elect an accelerated method of depreciation for tax purposes that provides for a higher depreciation expense in the early years compared to the straight-line method used for rate purposes. Because the net deferred tax liability represents income tax expenses that have been recognized but not paid, ADIT is treated as a deferred tax liability. The balance represents a non-investor source of cash that is available to the utility and is deducted from utility plant in service in the determination of rate base. *Id*. at 4.
[511] Effron Direct at 4. Mr. Vahos testified that the PATH Act will allow BGE to deduct as expense for tax purposes 50% of applicable 2015 plant additions, rather than record them as plant-in-service, resulting in reduced taxable income and reduced tax payable. Effron Rebuttal at 31.

RBAs 1 and 2, but the Company did not reflect the impact of the PATH Act on the balance of ADIT on BGE Exhibit DMV-6.[512] Mr. Effron testified that BGE should have adjusted the average ADIT balance throughout the test year based on the retroactive application of the Act. To remedy that omission, Mr. Effron reflected the impact of 50% bonus depreciation on ADIT related to AMI plant additions and other electric and gas plant additions for January 2015 through November 2015.

Mr. Vahos retorted on behalf of BGE that the Company did not receive any cash benefit from 2015 bonus depreciation during the test year (given that the law was not signed until December 2015), making an adjustment for that period inappropriate. Additionally, he argued that Mr. Effron's pro forma adjustment would violate the matching principle, which requires that all rate base and operating income components associated with an ADIT adjustment be adjusted consistently. Mr. Vahos claimed that if bonus depreciation is carried forward into the rate-effective period as proposed by Mr. Effron, then additional depreciation expense and rate base related to the 2015 plant additions should also be carried forward.[513] Mr. Vahos calculated that making this further adjustment would result in an increase to BGE's revenue requirements of $13.3 and $2.1 million for electric and gas, respectively.[514]

In his Surrebuttal testimony, Mr. Effron testified that as a result of the PATH Act, the tax depreciation associated with BGE's 2015 plant additions included in the Company's rate base was increased.[515] In other words, the 2015 bonus depreciation authorized by the PATH Act directly affected the tax attributes of plant included in

[512] Effron Direct at 4.
[513] Vahos Rebuttal at 31-32.
[514] Vahos Rebuttal at 30, Tr. at 731.
[515] Effron Surrebuttal at 3.

BGE's test year rate base. With regard to Mr. Vahos' testimony that BGE never received any cash benefit from the PATH Act during the test year, Mr. Effron retorted that BGE "is able to reflect the effect of 2015 bonus depreciation in subsequent estimated tax payments, and the additional cash resulting from the 2015 bonus depreciation will be available to the Company during the rate effective period."[516] He concluded that "[t]his is a known and measurable change that should be incorporated into the determination of the Company's revenue requirement."[517] Responding to Mr. Vahos' argument that the proposed adjustment violates the matching principle, Mr. Effron stated that he is "only proposing to recognize the effect of 2015 bonus depreciation on the average balance of ADIT for the test year."[518]

Mr. Effron argued that his proposal is consistent with the Company's inclusion of the average test year balance of plant in service in the Company's rate base and depreciation on that plant in test year expenses. Mr. Effron observed that he did not propose to annualize the effect of bonus depreciation to reflect the increased balance of ADIT as of November 30, 2015, making it unnecessary to state plant in service as of the end of test year or to annualize depreciation expense based on the end of test year plant in conjunction with his ADIT adjustment.

During the hearing, Mr. Vahos testified that despite the retroactive nature of the PATH Act, he did not restate BGE's balance sheets. "[W]e, as financial reporting experts, we don't go back and reopen prior periods and restate events simply because they

[516] Effron Surrebuttal at 4.
[517] Effron Surrebuttal at 4.
[518] Effron Surrebuttal at 4.

passed a law that is retroactive in nature."[519] Nevertheless, he stated that BGE does intend to take the benefits of bonus depreciation for 2015, which will likely lead to tax benefits (a reduction in taxes paid) when BGE files its 2016 return.[520] Mr. Effron agreed with that assessment, stating "Any subsequent estimated payments after the extension of the bonus depreciation in December 2015 would in effect capture the benefit of the extension of the bonus depreciation."[521]

During questions by the Commission, Staff witness Stinnette was asked whether any precedent existed that addressed how bonus depreciation should be treated given the explicit retroactive language contained in the PATH Act. Although Ms. Stinnette was unaware of any precedent at the time, she stated that she could provide an answer in response to the Commission's bench data request. On April 19, 2016, Staff filed a response to the Commission's inquiry, stating that only one state – Michigan – has had a proceeding addressing this issue, though no order had been issued.[522] Nevertheless, the utility in that case provided the impact on Deferred Federal Income Tax and reduced debt and equity 50/50.[523] Based on Ms. Stinnette's communications to the National Association of Regulatory Utility Commissioners, Staff further provided that "many Commissions are expecting companies to take a retroactive tax implementation and reflect it in the rate base deferred tax account." Finally, Staff stated that the Staff of the Virginia State Corporation Commission plans to recognize the retroactive change in tax

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[519] Tr. at 727.
[520] Tr. at 728, 887.
[521] Tr. at 1562.
[522] Michigan Public Service Commission, Case No. U-17999 – DTE Energy.
[523] Staff April 19, 2016 Response at 7.

law for ratemaking purposes, with the increase in ADIT resulting in a rate base deduction and reduced cost of service.

Commission Decision

We find that it is appropriate to reflect the impact of the 50% bonus depreciation on ADIT conferred by the PATH Act related to AMI plant additions and other electric and gas plant additions for January 2015 through November 2015. Accordingly, we accept Mr. Effron's recommendation to require BGE to adjust the average ADIT balance throughout the test year based on the retroactive application of the Act.

We are not persuaded by BGE's argument that it never received any cash benefit from 2015 bonus depreciation during the test year. The record demonstrates that BGE was or will be able to immediately deduct more depreciation expense for plant in service in calendar year 2015 from its 2015 tax payments than it would have been able to do absent the Act.[524] Whether that is acknowledged through a reduced 2015 quarterly tax payment or first quarter 2016 true up is not the critical consideration for ratemaking purposes.[525] Mr. Vahos confirmed that BGE does intend to take advantage of the benefits of bonus depreciation for 2015, which will likely lead to a reduction in taxes paid when BGE files its 2016 return.[526] Additionally, as OPC notes, the PATH Act "changed the tax attributes of the plant in service in 11 of the 12 months constituting the Company's test

[524] Tr. at 887.
[525] Mr. Effron confirmed during the hearing that: "Any subsequent estimated payments after the extension of the bonus depreciation in December 2015 would in effect capture the benefit of the extension of the bonus depreciation." Tr. at 1562.
[526] Tr. at 728, 887.

year."[527] We find that BGE ratepayers should receive some value from this tax reprieve, which was specifically made retroactive by Congress.[528]

We are likewise unpersuaded by BGE's argument that Mr. Effron's adjustment violates the matching principle. Mr. Vahos testified that if bonus depreciation is carried forward into the rate-effective period, then additional depreciation expense and rate base related to 2015 additions should also be carried forward, leading to an increase in BGE's revenue requirements of $13.3 for the Company's electric operations and $2.1 million for its gas operations. Nevertheless, we agree with Mr. Effron that BGE's proposal to include additional depreciation is unnecessary because he is merely proposing to recognize the effect of 2015 bonus depreciation on the average balance of ADIT for the test year. In other words, Mr. Vahos' argument assumes that Mr. Effron is making an adjustment in the rate effective period, which would invoke the matching principle. However, Mr. Effron did not do that – his changes were only to the test year.[529] We also agree with OPC that the Commission's decision here is consistent with its decision in a previous case related to the 1981 Economic Recovery Tax Act of 1981.[530]

Accordingly, we adopt OPC's recommendation on this issue, which results in a rate base reduction of $9,425,000 for BGE's electric operations and a reduction of $3,061,000 for its gas operations.

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[527] OPC Initial Brief at 38.

[528] *See* Tr. at 729, where Mr. Vahos refers to bonus depreciation as "a nice treat, nice Christmas present for us as a company and the customers."

[529] During the hearing, Mr. Vahos appears to have conceded that Mr. Effron did not propose to make adjustments in the rate effective period. Tr. at 731-32.

[530] *Re Baltimore Gas and Electric Company*, Case No. 7574, Order No. 65648, 73 Md.PSC. 61 (1982).

11. ***Riverside Remediation Accrual***

BGE accrued to expense $2.0 million based on its estimate of costs to investigate and remediate environmental issues at BGE's Riverside site, which housed a former gas purification plant.[531] Mr. Vahos testified that the accrual represented the minimum amount of expense it would take for BGE to complete the investigation and remediation. The estimated Riverside costs were charged to expense because they did not meet the criteria stated in the relevant accounting standards as to when environmental treatment costs may be capitalized.[532]

OPC witness Effron testified that it is not appropriate to include this accrual as an expense in the Company's gas revenue for three reasons: (i) The accrual does not represent an actual cost incurred by the Company – it is merely an accrual for *estimated* costs that the Company may incur in the future; (ii) including this item in test year expenses inappropriately treats it as a cost that will be incurred annually on a recurring basis; and (iii) it has not been demonstrated that these costs meet the Commission's established standards for recovery through rates. The treatment of this item as an ordinary annual expense is not appropriate for ratemaking purposes.

Mr. Vahos responded that BGE has paid $196,000 through November 2015 in actual investigation costs.[533] Additionally, he listed a series of actions BGE believes will be necessary to remediate the Riverside site, and explained that the remediation costs will be spent in accordance with BGE's legal obligation to comply with State and Federal environmental laws.

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[531] Vahos Rebuttal at 35.
[532] Effron Direct at 21.
[533] Vahos Rebuttal at 35.

Commission Decision

We will disallow BGE's accrual related to the investigation and remediation of the Riverside site. We agree with Mr. Effron that the accrual does not represent an actual cost incurred by the Company, but is rather an estimation for costs the Company expects to incur in the future. Moreover, including the accrual in test year expenses inappropriately treats it as a cost that will be incurred annually on a recurring basis. Accordingly, BGE is directed to eliminate the accrual from the pro forma test year gas operation and maintenance expenses.

We acknowledge Mr. Vahos' argument that the Company is acting to comply with State and Federal law, but BGE's treatment of the remediation costs is not appropriate in this instance. We accept Mr. Effron's recommendation that BGE will be authorized to establish a deferred charge account for the investigation and remediation costs associated with Riverside. After the funds are expended, we will determine the extent to which such costs are recoverable from customers and the appropriate period over which those costs should be amortized. Our decision results in an operating income adjustment of $1,193,000 for BGE's gas operations.

12. OIA 35: PHI Merger Costs and Savings

During the hearing, BGE witness Vahos responded to the Commission's questions regarding whether the merger consummation between Exelon and PHI resulted in any savings for BGE customers during the rate-effective period. He answered the questions using Company Exhibit 26, which presents calculations related to the synergies and costs to achieve merger benefits relative to the PHI merger.[534] Specifically, he testified that certain synergy savings could be measured and captured during the rate-effective period pursuant to the known and measurable standard and passed through to customers. Mr. Vahos estimated approximately $4 million in synergy savings in the first year after the merger (Year 1). He also stated that the Company proposed to set up a regulatory asset to capture the costs to achieve the merger benefits, which would yield a $1.2 million amortization cost.[535] The net benefit to customers at this time would therefore be approximately $2.8 million. Mr. Vahos further testified that the merger synergies would "ramp up over time."[536] Through Operating Income Adjustment 35, BGE proposed to account for the Year 1 projected net synergy savings to BGE customers during the rate year.

OPC objected to BGE's proposed handling of Exelon-PHI merger costs. OPC observed that one of the Commission's primary rationales for approving the merger was the synergy savings that Exelon projected would inure to Pepco and BGE ratepayers. OPC also noted that Mr. Vahos forecast that the synergy savings would increase markedly over time, at least for several years. Specifically, the Year 2 projected merger savings would increase to $10.3 million and the Year 3 merger benefits would reach $11.8 million.[537] OPC argued that allowing BGE to use the Year 1 projected merger benefits could be inequitable to BGE ratepayers if BGE failed to file a new rate case for more than approximately one year. In that event, Exelon shareholders would reap the increased net merger benefits instead of the ratepayers.

[534] Tr. at 953- 954.
[535] Tr. at 954.
[536] Tr. at 954.
[537] OPC Reply Brief at 17, citing Tr. at 1526. (Vahos).

OPC further lamented the asymmetry between the Company's proposed treatment of costs to achieve *vis-a-vis* merger benefits. OPC noted that BGE proposed to track all costs to achieve in a regulatory asset, so that they are recovered dollar for dollar, regardless of when the next rate case is filed, while some merger benefits that should be passed through to ratepayers may slip between rate cases and go to shareholders.

BGE responded that the Company's treatment of synergies and costs to achieve follow the Commission's typical practice. Mr. Vahos further noted that it is possible that some costs to achieve will not be collected in this rate case, though he acknowledged that the regulatory asset proposal will ensure that all costs to achieve are eventually collected.

OPC proposed two solutions to the apparent asymmetry. First, it suggested that OIA 35 reflect the projected Year 2 savings of $10.3 million, in lieu of the $4 million BGE proposed. Alternatively, OPC recommended that BGE reflect the last two months of Year 2 merger savings (option 2). OPC observed that the Exelon/PHI merger began on March 24, 2016 and the rate effective period in this proceeding commences in the beginning of June, 2016. Therefore, the rate year (June 2016 through June 2017) will overlap the Year 2 merger year (March 24, 2017 through March 24, 2018) by two months.[538] Accordingly, OPC recommended that the rate year synergy savings be modified such that they reflect 10/12 of Year 1 and 2/12 of Year 2.[539]

<u>Commission Decision</u>

The Commission accepts BGE's OIA 35 as adjusted by OPC's alternative two. OPC is correct that one of the primary reasons the Commission approved the Exelon-PHI

[538] Specifically, the overlap will be March 24, 2017 through May 31, 2017.
[539] OPC Reply Brief at 21.

merger was because of the synergy savings Exelon projected would pass through to Pepco and BGE ratepayers.[540] We are very concerned that the timing of BGE's next rate case could jeopardize synergy savings that BGE professed would inure to Maryland ratepayers. We also are concerned about the seeming asymmetry between BGE's proposed treatment of costs to achieve and synergy savings.

We find that OPC's alternative two provides an equitable solution and a fair compromise between the positions of BGE and OPC. OPC's first proposal – to fully reflect Year 2 savings – extends our reach beyond what is known and measurable. Alternative two, however, includes two months of Year 2 merger benefits that are within the rate year. Additionally, Mr. Vahos acknowledged that this approach was reasonable. *See* Tr. at 1527 stating "I follow your logic. Yes, I think that would be reasonable." We will also approve BGE's request for a regulatory asset to track its costs to achieve that accrue after the rate year and review those costs, in conjunction with merger benefits, in the next rate case. Our decision results in an operating income adjustment of $1,543,000 and a rate base adjustment of $197,000 for BGE's electric operations and an operating income adjustment of $660,000 and a rate base adjustment of $85,000 for the Company's gas operations.

C. Cost of Capital

1. ***Return on Equity***

The cost of capital is a utility's overall rate of return ("ROR"), which is the sum of the weighted returns the utility must earn on its stock (equity) and bonds (debt) to

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[540] Order No. 86990 at pp. 1, 4, 10 fn. 35, 66, 80, 81.

attract investors in those securities. Unlike return on debt, which is directly observable, return on equity ("ROE") must be estimated based on market data. No party opposed the cost of preference stock, short-term or long-term debt proposed by the Company. However, witnesses for BGE, OPC and Staff presented differing estimations regarding an appropriate ROE.

Party Positions

BGE

BGE witness Vahos requested that BGE receive an overall rate of return of 7.74% for electric and 7.69% for gas based on BGE's embedded cost of debt and preference stock as well as the returns on equity requested by BGE witness McKenzie.[541]

Mr. McKenzie presented BGE's case regarding the fair rate of return on equity that the Company requested it be authorized to earn on its investment in providing electric and gas utility service. Generally, he cautioned that regulatory signals – such as those sent by the Commission through its orders – are a major driver of investors' risk assessment for utilities.[542] He stated: "When investors are confident that a utility has reasonable and balanced regulation, they will make funds available even in times of turmoil in the financial markets."[543] He performed several quantitative analyses to estimate the cost of equity for separate reference groups of electric and gas utilities. Those analyses included the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on

[541] Vahos Direct at 28.
[542] McKenzie Direct at 6.
[543] McKenzie Direct at 6.

allowed ROEs for electric and gas utilities.[544] He also tested his recommended ROEs for BGE's electric and gas utility operations against alternative ROE benchmarks for his proxy groups, including application of the traditional Capital Asset Pricing Model ("CAPM.") Finally, he reviewed his utility quantitative analyses by applying the DCF model to a select group of low risk non-utility firms.

Mr. McKenzie testified that current capital market conditions are not representative of what investors expect in the future because they continue to reflect the Federal Reserve's "unprecedented monetary policy actions in the aftermath of the Great Recession."[545] Due to heightened risk, he argued that investors have repeatedly sought the "safe haven" of U.S. government bonds.[546] As a result of federal policies and volatility, Treasury bond yields have fallen significantly. He labeled current bond yields resulting from the Federal Reserve's policies "an anomaly" when compared to historical experience.[547] He further warned that historically low interest rates were not expected to continue, and that investors "continue to anticipate that interest rates will increase significantly from present levels."[548] He concluded that the long-term cost of capital will be substantially higher over the 2016 to 2020 time period.[549]

Mr. McKenzie testified about the risks of attrition, which he defined as "the deterioration of actual return below the allowed return that occurs when the relationships

[544] McKenzie Direct at 4.
[545] McKenzie Direct at 13. For example, Mr. McKenzie pointed to the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities of more than $4 trillion, an all-time high. McKenzie Direct at 17.
[546] McKenzie Direct at 13.
[547] McKenzie Direct at 14.
[548] McKenzie Direct at 15.
[549] Mr. McKenzie alluded to FERC's upward adjustment of its DCF range to compensate for what it considered unrepresentative market conditions and the risk of increased interest rates in the future. McKenzie Direct at 21.

between revenues, costs, and rate base used to establish rates do not reflect the actual costs incurred to serve customers during the period that rates are in effect."[550] Mr. Case testified that BGE has faced a consistent pattern of under-earning relative to its authorized return on equity in recent years, as a result of factors such as rising costs and flat customer growth.[551] He argued that those imbalances are exacerbated as the regulatory lag increases between the time when the data is used to establish rates and the date when rates go into effect. He testified that attrition and regulatory lag have been persistent problems for BGE over the last five years, resulting in the Company being unable to earn its authorized ROE.[552]

Given the risk of attrition, Mr. McKenzie questioned the Commission's reliance on a historic test year, arguing that investors are concerned about what can be expected in the future, "not what they might expect in theory if a historical test year were to repeat."[553] Mr. Case testified similarly, stating that in times of significant infrastructure investment and rising costs, relying on a historic test year "results in a poor matching of distribution rates with the actual cost of providing service during the rate effective period."[554]

In order to ensure that BGE's investors earn a return that is fair and commensurate with its authorized return, Mr. McKenzie urged the Commission to

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[550] McKenzie Direct at 7.
[551] Case Direct at 32. Mr. Case calculated that BGE has experienced a revenue shortfall of nearly 25% below its combined authorized return on equity, on average. Case Direct at 33.
[552] McKenzie Direct at 8. Although Mr. McKenzie stated that his discussion of attrition is synonymous with regulatory lag as that term is used by BGE's other witnesses, he discussed both terms in his Direct Testimony. *Id*. at 7-8, n. 4.
[553] McKenzie Direct at 7.
[554] Case Direct at 31-32.

approve an ROE "from the upper end of my range of reasonableness."[555] Case testified that "authorizing an ROE for BGE that is within the upper end of his range of reasonableness … is actually necessary under *Hope* and *Bluefield*" because of regulatory lag and the Commission's use of a historic test year.[556]

Mr. McKenzie utilized quantitative methods to estimate the cost of common equity for BGE's electric and gas operations. In doing so, he developed a list of 21 companies derived from Value Line's[557] electric utility industry groups that he determined were representative of BGE's electric operations and that would constitute his electric proxy group.[558] Similarly, he developed a list of ten publicly traded firms in Value Line's Natural Gas Utility industry to constitute his gas proxy group.[559] For his electric proxy group, he claimed that he developed a "conservative risk profile," in line with the Commission's judgment that BGE represents a lower-risk investment than the average utility.[560] Nevertheless, he did not remove utilities from his electric proxy group that own and operate generation assets. He further testified that adjustment mechanisms and cost trackers, such as BGE's Strategic Infrastructure Development and Enhancement ("STRIDE") surcharge and its Electric Reliability Investment ("ERI") initiative, had become increasingly prevalent in the utility industry in recent years and were comparable to those of his utility proxy groups.[561]

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[555] McKenzie Direct at 9.
[556] Case Direct at 5.
[557] As Mr. VanderHeyden explained, Value Line Investment Survey and other data provided by Value Line, Inc. provide a well-known source of data that can reasonably be expected to represent the information known to the general body of investors. VanderHeyden Direct at 5.
[558] McKenzie Direct at 23.
[559] McKenzie Direct at 25-26.
[560] McKenzie Direct at 27, citing Order No. 85374 at 64.
[561] McKenzie Direct at 28.

Among other tools, Mr. McKenzie utilized the DCF analysis to estimate the cost of common equity to BGE. The DCF model is designed to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model estimates the cash flows investors expect to receive from the stock through future dividends and capital gains.[562] Because common stocks are more risky than investments in long-term bonds, Mr. McKenzie eliminated DCF results that in his opinion were not sufficiently higher than the yield available on less risky utility bonds.[563] Specifically, he eliminated eight low-end DCF estimates ranging from 5.4% to 6.9%.[564] However, Mr. McKenzie did not eliminate any high-end DCF values for the electric group, finding that "there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values."[565] After eliminating values he deemed illogical, Mr. McKenzie's constant growth DCF model produced an ROE range of 9.3% to 9.7% for BGE's electric operations.[566] Similarly, Mr. McKenzie's constant growth DCF analysis produced an ROE range of 8.8% to 10.4% for BGE's gas operations.[567]

Mr. McKenzie also evaluated BGE's common equity requirements through the ECAPM model, a variant of the traditional CAPM. The CAPM analysis determines an equity risk premium for a particular stock based on its relative risk against the overall stock market.[568] Using this model, the relevant risk of an asset (such as an individual

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[562] McKenzie Direct at 34. Mr. McKenzie noted that the DCF model can be set forth mathematically (in its simplified "constant growth" form) as $k_e = D_1/P_0 + g$, where k_e equals the cost of common equity, D_1 represents the expected dividend per share, P_0 is equal to the current price per share, and g is equal to the investors' long-term growth expectations. McKenzie Direct at 34-35. *See also* VanderHeyden Direct at 11.
[563] McKenzie Direct at 41.
[564] McKenzie Direct at 43-44.
[565] McKenzie Direct at 44.
[566] McKenzie Direct at 10.
[567] McKenzie Direct at 11.
[568] VanderHeyden Direct at 17.

stock), is its volatility relative to the market as a whole.[569] That model uses the beta coefficient to measure a utility's stock price volatility relative to the market, and reflects the tendency of a stock's price to follow changes in the market.[570] Mr. McKenzie employed the ECAPM variant as a result of empirical tests that demonstrate that low-beta securities earn returns somewhat higher than CAPM would predict and that high-beta securities earn less than predicted.[571] Additionally, Mr. McKenzie added a "size premium" to the ECAPM result to account for research that indicates that the ECAPM does not fully account for differences in rates of return attributable to firm size.[572] Mr. McKenzie's ECAPM analysis produced an ROE range of 10.5% to 10.8% for his electric group.[573] Similarly, Mr. McKenzie's ECAPM analysis produced an ROE range of 10.3% to 12.18% for his gas group.

Mr. McKenzie additionally utilized a utility risk premium approach to estimate BGE's common equity requirements. The risk premium method estimates the additional return investors require to forgo the relative safety of bonds and to bear the higher risks associated with common stocks, and then adds this equity risk premium to the current yield on bonds.[574] Mr. McKenzie based his estimates of equity risk premium on surveys of previously authorized ROEs. He testified that when interest rates are high, equity risk

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[569] McKenzie Direct at 46. The CAPM can be expressed mathematically as $R_j = R_f + B_j(R_m – R_f)$ where R_j is the required rate of return for stock j, R_f is the risk-free rate, B_j is the beta, or systematic risk, for stock j, and R_m is the expected return on the market portfolio. Regarding R_f, a stock that tends to respond less to market movements has a beta less than 1.0 while stocks that tend to be more volatile than the market have betas greater than 1.0. McKenzie Direct at 46.
[570] McKenzie Direct at 25.
[571] McKenzie Direct at 47. The ECAPM adjusts for this phenomenon through the following weighted formula:
$R_j = R_f + 0.25(R_m – R_f) + 0.75[B_j(R_m – R_f)]$.
[572] McKenzie Direct at 49.
[573] McKenzie Direct at 10.
[574] McKenzie Direct at 51.

premiums narrow, but when interest rates are low, as they are now, the risk premiums become greater.[575] Mr. McKenzie's risk utility premium approach produced an ROE range of 10.0% to 11.1% for electric utilities.[576] Similarly, Mr. McKenzie's risk utility premium approach produced an ROE range of 9.60% to 10.6% for gas utilities.[577]

Based on the results of his analyses, Mr. McKenzie recommended a range of 9.7% to 10.9% for BGE's electric operations.[578] Similarly, he recommended a range of 9.6% to 10.8% for BGE's gas operations.[579] Given the risk of attrition and other economic factors, he recommended an ROE in the upper range of reasonableness of 10.6% for BGE's electric utility operations and an ROE of 10.5% for the Company's gas utility operations.[580]

Mr. McKenzie's final ROE recommendations include a ten basis point adjustment for flotation costs.[581] He explained that when equity is raised through the sale of common stock, there are costs associated with floating the new equity securities in the form of legal, accounting and printing costs as well as the fees and discounts paid to compensate brokers for selling the stock to the public.[582] Mr. McKenzie observed that while debt flotation costs are recorded on the books of the utility and amortized over the life of the issue, that is not the case for equity issuance costs. He testified that unless they

[575] McKenzie Direct at 52. Mr. McKenzie opined that today's unprecedented low bond yields implied "a sharp increase in the equity risk premium that investors require" to accept the added risk of utility common stocks vs. bonds. McKenzie Direct at 53.
[576] McKenzie Direct at 10.
[577] McKenzie Direct at 11.
[578] McKenzie Direct at 10.
[579] McKenzie Direct at 11.
[580] McKenzie Direct at 9-10. Specifically, Mr. McKenzie chose 10.6% for BGE's electric operations as the midpoint of the upper end of his ROE range. McKenzie Direct at 11. His calculation for BGE's gas operations employed a similar methodology. McKenzie Direct at 12.
[581] McKenzie Direct at 11, 60. For example, the addition of flotation costs increased his gas ROE range from his original 9.5% to 10.7% range, to 9.6% to 10.8%.
[582] McKenzie Direct at 55.

are accounted for, such as through an upward adjustment to the cost of equity, the utility's revenue requirement will not fully reflect all of the costs incurred for the use of investors' funds.[583] Mr. McKenzie further testified that an adjustment for flotation costs associated with past equity issues is appropriate even when the utility is not contemplating any new sales of common stock.

Finally, Mr. McKenzie utilized alternative tests to demonstrate that the results of his primary ROE analyses were reasonable. Specifically, he used the traditional CAPM analysis, an expected earnings approach, and a DCF analysis for a select group of low-risk, non-utility firms to confirm the reasonableness of his results. In Mr. McKenzie's opinion, the alternative benchmarks he utilized confirmed the reasonableness of his recommended ROE ranges of 9.7% to 10.9% for BGE electric and 9.6% to 10.8% for BGE's gas operations.[584]

Staff

Mr. VanderHeyden, Director of the Commission's Electricity Division, provided testimony on behalf of Staff on BGE's electric distribution service. Regarding proxy groups, he testified that a utility's return should be comparable to other companies of similar risk. In that regard, he observed that BGE is solely a distribution company and does not include any generation or transmission assets in its rate base.[585] Unfortunately, few companies are organized as stand-alone electric distribution companies, making a perfectly representative proxy group difficult to achieve. Mr. VanderHeyden noted that

[583] McKenzie Direct at 55-56.
[584] McKenzie Direct at 68-69.
[585] VanderHeyden Direct at 8.

many of Value Line's electric utility groups have other operations, such as generation and non-regulated businesses.

Mr. VanderHeyden derived his electric utility proxy group primarily from the proxy group utilized by BGE witness Mr. McKenzie. However, Mr. VanderHeyden removed Duke Energy, NextEra Energy, and PPL Corporation from that group, because of their recent or proposed mergers or spinoffs.[586]

Mr. VanderHeyden derived his recommended ROE for BGE by averaging the results of his DCF and CAPM results, after excluding the results from certain methods that he concluded were outside of a reasonable range. He also utilized the Internal Rate of Return/Discounted Cash Flow method ("IRR/DCF") and the Risk Premium Buildup Method.

Regarding the DCF, Mr. VanderHeyden used data from Value Line to obtain the annual dividend for each year. However, given the significant investment in reliability spending for many electric utilities, Mr. VanderHeyden excluded the low dividend growth results from his DCF calculation because in his opinion, many utilities would be unable or unwilling to increase dividends while spending heavily on reliability improvements.[587] Mr. VanderHeyden also excluded companies from his DCF with earnings growth rates outside a reasonable range. For example, he removed El Paso Electric Co. and Edison International because their calculations indicated an ROE less

[586] VanderHeyden Direct at 8.
[587] VanderHeyden Direct at 12.

than 7%.[588] Using the DCF method, Mr. VanderHeyden calculated an ROE of 9.66% for BGE.[589]

The IRR/DCF method is a type of DCF that focuses on the capital appreciation of an investment. It determines an ROE based solely on the dividend projections and the change in the price of a stock over a fixed period.[590] Specifically, it is calculated on the projected capital gain on the stock and the dividend projections over a four-year period.[591] Mr. VanderHeyden calculated the IRR/DCF by averaging the IRR results for each of the companies in his electric proxy group. Using this method, Mr. VanderHeyden calculated an ROE of 9.44%.

The Risk Premium Buildup Method calculates the ROE for a given investment by adding a risk-related premium to the return on a riskless investment. The Risk Premium Buildup Method adds to the market's ROE (for example, the S&P 500) two components, (i) an equity risk premium, and (ii) the risk-free rate, which here was represented by the 30-year Treasury bond.[592] This method produced an ROE of 7.5% for the industry category of "electric services industry group," which is similar to, but not the same as, Mr. VanderHeyden's electric proxy group.[593]

Finally, using the CAPM method, Mr. VanderHeyden calculated an ROE of 9.71% for BGE.[594] He reached his final recommendation of 9.68% for BGE's electric

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[588] VanderHeyden Direct at 13.
[589] VanderHeyden Direct at 10.
[590] VanderHeyden Direct at 13-14.
[591] The IRR/DCF differs from the traditional DCF in this regard. In the traditional DCF method, the present value is the result of a continuing stream of dividends. Mr. VanderHeyden characterized the IRR/DCF as providing "a short-term view of investor returns, but [one which] may not properly account for the longer-term utility investor expectations." VanderHeyden Direct at 15.
[592] VanderHeyden Direct at 15.
[593] VanderHeyden Direct at 15.
[594] VanderHeyden Direct at 17.

operations based on the average of his DCF and the CAPM analyses. He excluded the RP Buildup Method because its results "are outside of the range of recent rate orders and do not reflect current investor expectations."[595] He excluded the IRR/DCF because it is based on similar data as the DCF method and including both would overweight dividend yield based methods. Finally, he chose to average the DCF and CAPM results because "it is reasonable to weight differently determined results equally using the assumption that no single method is superior."[596]

Mr. VanderHeyden testified against BGE's request to be authorized an ROE that reflects flotation costs. He argued that the Commission has been clear in previous orders that an award for flotation costs would be granted only based on verifiable costs of issuing new stock. Because BGE has not provided information in its Application on these threshold issues, Mr. VanderHeyden recommended against an adjustment for flotation costs to BGE's ROE.[597]

Mr. VanderHeyden recommended a rate of return of 7.46% for BGE's electric operations. That figure is based on his ROE recommendation discussed above as well as BGE's capital structure calculations regarding long-term debt, short-term debt, preferred stock, and common stock.

Mr. VanderHeyden critiqued the cost of capital analysis provided by BGE witness Mr. McKenzie. Mr. VanderHeyden noted that the DCF analyses conducted by BGE and Staff were "close"[598] in results, with the primary difference being BGE's use of the

[595] VanderHeyden Direct at 19.
[596] VanderHeyden Direct at 19.
[597] VanderHeyden Direct at 21, citing Commission Order No. 86441 at 88.
[598] Mr. VanderHeyden observed that Mr. McKenzie's DCF produced an average result of 9.4% compared to Staff's 9.66%. Nevertheless, Mr. McKenzie used the DCF midpoint of 9.7%.

midpoint for its result. Mr. VanderHeyden observed that unlike BGE, he did not use the ECAPM method. That is because he found the use of an adjustment for beta to be unnecessary in this case and also because the ECAPM method "was not a mainstream method."[599] Additionally, Mr. VanderHeyden objected to Mr. McKenzie's use of a size adjustment in his ECAPM method, seeing no merit for such an adjustment with regard to regulated utilities in Maryland. Mr. VanderHeyden also characterized Mr. McKenzie's risk premium analysis as incomplete because the historical authorized returns granted by state commissions may be higher or lower than the returns on market equity that current investors expect.[600]

Finally, Mr. VanderHeyden testified that he would revise Mr. McKenzie's results by using the average of his complete proxy group rather than taking a midpoint, yielding a result of 9.4%. He would exclude the risk premium and ECAPM analyses. He would then average the 9.4% with his CAPM result of 9.71%, which would result in a final ROE of 9.55%.[601] Mr. VanderHeyden concluded that BGE's cost of equity capital is 9.68% and that the Company's overall rate of return is 7.46%.[602]

Jennifer Ward, Regulatory Economist within the Commission's Telecommunications, Gas, and Water Division, testified on behalf of Staff regarding cost of capital for BGE's gas distribution service. She calculated her recommended ROE using the traditional DCF and CAPM analyses. In assembling her proxy group, she started with the recommended gas proxy group of Mr. McKenzie and made two changes. First, she removed Piedmont Natural Gas from the group, observing that Piedmont is

[599] VanderHeyden Direct at 23-24.
[600] VanderHeyden Direct at 26.
[601] VanderHeyden Direct at 27.
[602] VanderHeyden Direct at 2.

currently subject to a pending acquisition with Duke Energy. Ms. Ward testified that the pending acquisition creates market expectations that may skew the results of the ROE analysis. Second, she conducted an outlier analysis to eliminate any outlier growth rates from the proxy group, and removed NiSource and New Jersey Resources from her recommended proxy group.[603] Ms. Ward testified that the resulting proxy group matched BGE's risk profile. She observed that BGE is a public utility company that is widely regarded as having a low credit risk, receiving a Moody's credit rating of A3 for its long term debt.[604] The gas proxy group also exhibits a low risk profile, with five of the seven companies in the group receiving credit ratings from Moody's of A3 or higher.

In her DCF analysis, Ms. Ward did not rely exclusively on dividend per share growth rates, but followed FERC practice in also considering the short term dividend yield and the long term economic growth rate. Ms. Ward's DCF analysis resulted in an ROE of 9.62%.[605] Ms. Ward also conducted a CAPM analysis. Because she found that current economic conditions have resulted in unusually low interest rates, she used the mean of the projected 30-year note yields for the time period 2015 through 2019 to more accurately capture the future expectations of investors and anticipated interest rate increases in the near future.[606] Ms. Ward testified that it was not appropriate to make an explicit size adjustment in her CAPM analysis, as Mr. McKenzie had done. She explained that using beta coefficients for each proxy group company incorporates the risk of a company to a well-diversified portfolio, thereby embedding in the beta coefficient a

[603] Ward Direct at 7.
[604] Ward Direct at 8.
[605] Ward Direct at 11.
[606] Ward Direct at 12.

size adjustment and making further adjustment unnecessary and inappropriate.[607] Ms. Ward also declined to use a risk premium method similar to Mr. McKenzie. She stated that authorized returns from a diverse group of state commissions often reflect issues specific to a particular utility, geographic area, or regulatory environment, making awarded ROEs a poor proxy for a specific risk profile.

Ms. Ward testified against BGE's request for flotation costs. She stated that Staff asked BGE to provide evidence of any incurred expenses, investments, or fees related to flotation costs, and the Company responded that it "does not issue publicly traded common stock and, therefore, will not incur flotation costs directly."[608] She concluded that without evidence of known and measurable costs, she cannot recommend an allowance for flotation costs.

Ms. Ward adjusted her recommended ROE based in part on reduced risk to BGE as a result of its STRIDE initiative. Ms. Ward testified that STRIDE authorizes BGE to accelerate cost recovery related to certain gas infrastructure investments, thereby reducing the Company's risk. The program allows BGE to more quickly recover certain infrastructure expenses and improve cash flows, while improving the safety of aging infrastructure and reducing leakages.[609] She determined that attributing a precise value to the reduction in risk from STRIDE was difficult, but testified that it was appropriate to acknowledge the reduced risk by recommending an ROE equal to the lower end of her range of reasonableness.[610]

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[607] Ward Direct at 14.
[608] Ward Direct at 16.
[609] Ward Direct at 16-17.
[610] Ward Direct at 17.

Ms. Ward concluded that the range of reasonableness for BGE's ROE is 9.62% to 9.81%. Based on that range, she determined that an ROE of 9.60% will adequately compensate BGE for the risks associated with the provision of gas service in Maryland.[611] Furthermore, she calculated that an overall rate of return of 7.41% for BGE is adequate and appropriate.[612]

OPC

Dr. J. Randall Woolridge testified on behalf of OPC. He adopted BGE's proposed short-term debt, long-term debt, and preferred stock costs rates. His main contention was in the calculation of BGE's ROE. Dr. Woolridge applied the DCF and CAPM methods to proxy groups of publicly-held electric utilities and gas distribution companies to determine an equity cost ratio of 8.7% for BGE's electric operations and an equity cost ratio of 8.6% for BGE's gas operations.[613] He testified that these recommendations were on the upper end of his equity cost rate range of 8.1% to 8.7%. When BGE's capital structure and senior capital cost rates are taken into consideration, Dr. Woolridge calculated an overall rate of return of 6.75% for BGE's electric utility operations and 6.70% for BGE's gas distribution operations.[614]

Dr. Woolridge relied primarily on the DCF analysis for his ROE determination, finding that the DCF method provides the best measure of equity cost rates for public

[611] Although it appears that Ms. Ward's final recommended ROE is below the bottom of her range of reasonableness, she testified that her practice is to round to the nearest 0.05, which led to her recommended ROE for BGE's gas operations of 9.60%. Tr. at 1962.
[612] Ward Direct at 4.
[613] Woolridge Direct at 4.
[614] Woolridge Direct at 4.

utilities.[615] He also performed the CAPM analysis, but put less weight on its results because the CAPM provides a "less reliable indication of equity cost rates for public utilities," in his opinion.[616] In deriving the DCF growth rate forecast for his proxy group, Dr. Woolridge did not rely exclusively on the earnings per share forecasts, arguing that "it is well known that the long-term [earnings per share] growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased."[617] The DCF analysis for Dr. Woolridge's electric proxy group produced an equity cost rate of 8.7% and for his gas distribution proxy group produced an equity cost rate of 8.6%.[618] Using the CAPM analysis, Dr. Woolridge determined a cost of equity for the electric proxy group of 8.10%. For the gas proxy, he calculated a cost of equity of 8.30%.[619] Given the results of his DCF and CAPM analyses, he computed an equity cost rate range of 8.1% to 8.7% for the electric proxy group and 8.3% to 8.6% for the gas proxy group.[620] Because he relied primarily on the DCF, he chose a final ROE recommendation at the upper end of the range and concluded that the appropriate equity cost rate is 8.7% for BGE's electric operations and 8.6% for the Company's gas operations.

Dr. Woolridge observed the return the Commission has authorized for BGE has been consistent over the years. In Case Nos. 9326 and 9299, the Commission authorized an ROE of 9.75% for BGE's electric operations and 9.60% for BGE's gas distribution operations. Dr. Woolridge testified that since December 13, 2013, when Case No. 9326

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[615] Woolridge Direct at 36. Given the utility industry's relative stability, maturity of demand for utility services, and regulated nature, Dr. Woolridge testified that the utility business is in the steady-state or constant-growth stage of the three-stage DCF, making it well-suited to the DCF analysis. Dr. Woolridge Direct at 40.
[616] Woolridge Direct at 37.
[617] Woolridge Direct at 47.
[618] Woolridge Direct at 51.
[619] Woolridge Direct at 60-61.
[620] Woolridge Direct at 61.

was decided, BGE has become "an even lower risk investment operating in an even lower interest rate environment."[621]

Dr. Woolridge argued that capital costs have declined since the Commission last addressed BGE's ROE. Although he acknowledged that the Federal Reserve ended its Quantitative Easing III bond buying program in 2014, the "dire predictions of higher long-term rates have proved to be 100 percent wrong."[622] He noted that the 30-year Treasury yield, which was 3.88% on December 13, 2013, declined to the 2.5% range in early 2015 and remained below 3.0% for the remainder of 2015.[623] Similarly, long-term rates were not impacted by the Federal Reserve's decision to increase the target rate for Federal Funds. Dr. Woolridge observed that "there is no direct link between the federal funds rate and long-term interest rates."[624] Regarding his prediction for long-term rates, he argued that slowing economic growth coupled with significant and growing "stored wealth that is available to fund investments" will keep interest rates low for the foreseeable future.[625] He testified that U.S. GDP growth remains low by historic standards, inflationary expectations remain low in this country, and global economic growth is slowing, with Europe stagnant and China slowing significantly.[626] He also testified that economists have consistently over-forecast interest rate increases and that "interest rates have not fulfilled the predictions."[627] Finally, addressing Mr. McKenzie's warning that a sudden interest rate increase is just around the corner, Dr. Woolridge

[621] Woolridge Direct at 6.
[622] Woolridge Direct at 6.
[623] Woolridge Direct at 6.
[624] Woolridge Direct at 15-16.
[625] Woolridge Direct at 18-20. He referred to this phenomenon as "more wealth chasing few opportunities for investment rewards," and alluded to Ben Bernanke's characterization of the phenomenon as a "global savings glut." Woolridge Direct at 20.
[626] Woolridge Direct at 23.
[627] Woolridge Direct at 14.

testified that: "Investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns."[628]

Beyond interest rates, Dr. Woolridge testified that BGE is in a better position because of its credit rating. Dr. Woolridge testified that BGE's credit rating has improved since its last rate case, from Baa1 to A3.[629] Dr. Woolridge also claimed that authorized ROEs for electric utilities and gas distribution companies around the country have decreased since BGE's last rate case. He cited data from Regulatory Research Associates indicating that authorized ROEs for gas distribution companies have declined from 9.94% in 2012, to 9.68% in 2013, to 9.78% in 2014, and to 9.60% in 2015.[630] Similarly, the authorized ROEs for gas distribution companies have declined from 9.94% in 2012 to 9.60% in 2015, according to the same source.

Dr. Woolridge criticized BGE's Mr. McKenzie's cost of capital evaluation. First, he argued that Mr. McKenzie improperly eliminated low-end equity and cost rate results that he determined were too low. Second, Dr. Woolridge argued that Mr. McKenzie "relied excessively on the overly optimistic and upwardly biased earnings per share growth rate forecasts of Wall Street analysts."[631] Third, Mr. McKenzie made several errors regarding his CAPM analysis, including using the ECAPM in place of the traditional analysis, making an unwarranted size adjustment, and using an inflated market risk premium that does not reflect current market fundamentals. Specifically, Dr. Woolridge argued that Mr. McKenzie's use of an expected stock market return of 11.7%,

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[628] Woolridge Direct at 24.
[629] Woolridge Direct at 7, referencing Moody's January 30, 2014 rating upgrade.
[630] Woolridge Direct at 7.
[631] Woolridge Direct at 8.

based primarily on analysts' earnings per share growth projections, was unrealistic.[632] Dr. Woolridge also criticized Mr. McKenzie's utility risk premium model because (i) the approach is a gauge of state commission behavior and not investor behavior; (ii) the methodology produces an inflated measure of the risk premium; and (iii) state commission authorized returns have been greater than necessary to attract investors.[633] Like Staff witness Mr. VanderHeyden, Dr. Woolridge criticized Mr. McKenzie for including a flotation cost adjustment "without identifying any flotation costs actually paid by BGE."[634]

Party Responses

BGE and OPC submitted rebuttal testimony regarding cost of capital. Mr. Vahos testified that OPC witness Woolridge's recommended ROEs of 8.7% and 8.6% for electric and gas should be rejected because they would be lower than any of the 332 ROEs granted to an electric or gas utility by a state commission over the last five years.[635] Mr. Vahos also observed that Dr. Woolridge's current recommendation is even lower than OPC's 9.0% ROE proposal in Case No. 9336, which was rejected by the Commission as too low in its July 2014 order.[636]

Mr. Vahos criticized Staff witness Ward for including in her ROE recommendation a negative adjustment for STRIDE. Mr. Vahos explained that the gas proxy groups in this proceeding already reflect the market's perception of gas infrastructure cost recovery programs like STRIDE. He noted that a recent Edison

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[632] Woolridge Direct at 9.
[633] Woolridge Direct at 11.
[634] Woolridge Direct at 11.
[635] Vahos Rebuttal at 23. *See also* McKenzie Rebuttal at 23.
[636] Vahos Rebuttal at 24, citing Case No. 9336, Order No. 86441 at 87.

Electric Institute report found that 37 of 50 states in the U.S. use gas capital cost trackers. Additionally, he downplayed the importance of STRIDE, stating 2015 STRIDE revenues were only 1% of total gas distribution revenues.[637] In an apparent criticism of her rounding practice, Mr. Vahos denigrated Ms. Ward for recommending an ROE that is below her range of reasonableness, not just on the lower end of her range.[638] Mr. Vahos warned that authorizing a low ROE could hurt the Company's credit rating, given that credit rating agencies view cash flows as one of the most important aspects of a company's financial position since they are essential to meeting debt obligations.[639] Mr. Vahos reiterated his concern that the Commission should authorize ROEs from the upper end of BGE's proposed ranges of reasonableness in order to address the phenomenon of attrition, or regulatory lag. Mr. Vahos maintained that neither OPC nor Staff presented any evidence on this issue.

In his Rebuttal Testimony, Mr. Case reiterated his position that since 2012, BGE has under-earned its authorized ROE by approximately 25%, due in part to the Commission's practice of utilizing a historic test period. He criticized OPC's "extreme" ROE position and asked that the Commission approve a return that incorporates the Company's position on attrition.[640]

Mr. McKenzie's Rebuttal Testimony presented numerous criticisms of the ROE testimony of Staff witnesses VanderHeyden and Ward as well as OPC witness Woolridge. He claimed that Ms. Ward underestimated the dividend yield component of the DCF model by relying improperly on dividends for a past period (2015), rather than

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[637] Vahos Rebuttal at 25.
[638] Vahos Rebuttal at 25.
[639] Vahos Rebuttal at 27-28.
[640] Case Rebuttal at 32.

for the year-ahead period (2016).[641] Mr. McKenzie also disagreed with Ms. Ward's use of dividend per share growth projections in lieu of his utilization of earnings per share.[642] He found fault with Mr. VanderHeyden and Ms. Ward for ignoring a size adjustment when applying the CAPM analysis.[643]

Mr. McKenzie reiterated his support for the ECAPM methodology, arguing that financial research has documented a downward bias in CAPM estimates for low beta industries like rate-regulated utilities. Mr. McKenzie also testified that other Staff witnesses have employed the ECAPM analysis in past proceedings.[644] Mr. McKenzie defended his use of the utility risk premium model, arguing that it provides meaningful insight into current investor expectations of a reasonable ROE, contrary to the contentions of the Staff witnesses.[645] Mr. McKenzie disagreed with Staff's recommendation not to include an adjustment for flotation costs, stating that the relevant financial literature has recognized that a flotation cost adjustment in all future years is required even if no further stock issuances are contemplated.[646] Mr. McKenzie also disagreed with Ms. Ward's decision to apply to BGE's gas operations the lower end of her reasonable ROE range as a result of BGE's STRIDE rider, referring to her adjustment as an "ROE penalty."[647] He observed that many companies in the proxy group had mechanisms similar to STRIDE, concluding that "there is no basis to distinguish between

[641] McKenzie Rebuttal at 5-6.
[642] McKenzie Rebuttal at 6-7.
[643] McKenzie Rebuttal at 9-10.
[644] Mr. McKenzie referenced previous BGE (Case No. 9326) and Pepco (Case No. 9336) rate cases. *Id*. at 11.
[645] McKenzie Rebuttal at 12-13.
[646] McKenzie Rebuttal at 14.
[647] McKenzie Rebuttal at 15.

BGE and its industry peers on the basis of [such] regulatory mechanisms."[648] Finally, Mr. McKenzie criticized the Staff witnesses for failing to address regulatory lag, claiming that there has been a chronic shortfall between BGE's authorized ROE and its actual earned returns. He reiterated his position that the attrition problem warrants an ROE at the upper end of the range of results.

Mr. McKenzie chastised OPC's Dr. Woolridge for recommending ROEs that he considered "extreme outliers."[649] He noted that Dr. Woolridge's proposed ROEs are at least 100 basis points lower than the currently authorized ROEs for BGE's utility operations, and that they are approximately 100 basis points less than the Staff's recommendations in this case. He also accused Dr. Woolridge of ignoring clear evidence of investors' expectations of higher interest rates as well as the implications of widening yield spreads between utility and Treasury bonds, which in Mr. McKenzie's opinion demonstrates that investors' required risk premium for common stocks over Treasury bonds has increased.[650] Mr. McKenzie also challenged Dr. Woolridge's determination that interest rates have fallen, arguing that unlike risk-free Treasury rates, the premium for public utility debt has increased.[651]

Mr. McKenzie criticized Dr. Woolridge's methodology for creating proxy groups as well as his focus on market to book ratios. He specifically disagreed with Dr. Woolridge's requirement that a company derive at least 50 percent of its revenues from regulated utility operations.[652] Mr. McKenzie claimed that Dr. Woolridge erred in

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648 McKenzie Rebuttal at 17.
649 McKenzie Rebuttal at 4.
650 McKenzie Rebuttal 42-43.
651 McKenzie Rebuttal at 26-27.
652 McKenzie Rebuttal at 25.

applying his DCF analysis by failing to illuminate and discard illogical data, alleging that he relied upon “a mishmash of historical and projected growth rates over varying time periods” for earnings, dividends, and book values.”[653] Mr. McKenzie claimed that Dr. Woolridge could have obtained almost any DCF result based on the data he cited.

Finally, Mr. McKenzie argued that Dr. Woolridge’s CAPM results were unreliable because they were based on a “hodge-podge of historical data that fail to reflect forward-looking expectations.”[654] Mr. McKenzie argued the CAPM analysis is *ex ante* and must be applied using data that reflects the expectations of actual investors in the market. Mr. McKenzie concluded that Dr. Woolridge’s results are “downward biased, unreliable, and should be ignored.”[655]

In his Rebuttal Testimony, OPC’s Dr. Woolridge testified that Staff’s VanderHeyden erred in his ROE analysis by (i) failing to consider or evaluate the riskiness of BGE relative to other electric utilities; (ii) arbitrarily eliminating the results of the IRR/DCF and Risk Premium Buildup methods (which produced lower ROEs) and instead relying exclusively on the higher DCF and CAPM results; (iii) using in his DCF analysis inappropriate growth rates and relying on two high-end outliers that skew the distribution of ROE results; and (iv) utilizing a flawed measure of the equity risk premium in his CAPM analysis.[656]

Dr. Woolridge also critiqued Ms. Ward’s testimony, arguing that she erred by eliminating two low-end DCF ROEs (New Jersey Resources and NiSource), but failed to

[653] McKenzie Rebuttal at 41.
[654] McKenzie Rebuttal at 4.
[655] *Id*.
[656] Woolridge Rebuttal at 5. Dr. Woolridge took aim at Mr. VanderHeyden’s proxy group, arguing that he erred by including ITC Holdings, which is an electric transmission company, not a traditional electric utility company. Dr. Woolridge argued that as a result, ITC has a risk profile that is higher than BGE’s. Woolridge Rebuttal at 7.

eliminate corresponding high-end returns.[657] He also criticized her for erroneously using historical annual stock returns in her CAPM analysis to measure an *ex ante* equity risk premium.

In his Surrebuttal Testimony, Mr. McKenzie defended his as well as Staff's cost of capital analyses from the criticisms of Dr. Woolridge. He stated that the proxy groups BGE and Staff selected reflected a conservative risk profile.[658] He also stated that Mr. VanderHeyden properly excluded the results of his risk premium build-up method, notwithstanding the objections of Dr. Woolridge. He also defended Mr. VanderHeyden's use of earnings per share and his elimination of low-end DCF estimates in his DCF analysis.

Dr. Woolridge provided Surrebuttal Testimony responding to BGE's witnesses on the topics of changes since the last rate case, capital market conditions, equity cost rate issues, and credit ratings. Dr. Woolridge testified that authorized ROEs for electric utilities and gas distribution companies have decreased since BGE's last rate case, to an average of 9.58% for electric utilities and 9.60% for gas distribution companies in 2015.[659] Regarding future interest rates, Dr. Woolridge observed that in BGE's last rate case (Case No. 9326), BGE's cost of capital witness projected dire warnings of imminent rate increases, a prediction that did not come to fruition.[660] Dr. Woolridge stated that the cost of long-term capital did not increase significantly in the years after BGE's last rate case. He also claimed that Mr. McKenzie erred by assuming (i) that investors share economists' erroneous views that higher interest rates are approaching; and (ii) that these

[657] Woolridge Rebuttal at 15.
[658] McKenzie Surrebuttal at 2.
[659] Woolridge Surrebuttal at 5-6.
[660] Woolridge Surrebuttal at 7.

views are incorporated into the investors' decision making. Regarding methodology, Dr. Woolridge defended his use, and/or criticized Mr. McKenzie's application, of proxy groups; constant-growth DCF analysis; application of the CAPM; application of the bond yield risk premium method; inclusion of flotation cost adjustment; and final ROE recommendations.

In his Surrebuttal Testimony, Staff witness VanderHeyden defended his ROE analysis from Dr. Woolridge's criticisms regarding: (i) analysis of BGE's riskiness relative to the proxy group; (ii) removal of the IRR/DCF and Buildup methods; (iii) reasonableness of the DCF Results, including composition of the proxy group, use of Value Line equity growth rates, removal of outliers, and skewed results; and (iv) CAPM analysis, including use of historical market risk premium. Mr. VanderHeyden also provided Surrebuttal response to Mr. McKenzie's critiques regarding: (i) lack of a size adjustment in the CAPM analysis; (ii) election of the CAPM method over the ECAPM analysis; (iii) the validity of authorized ROE as a risk premium method; (iv) the need for flotation expense as a requirement for a flotation ROE adjustment; and (v) the lack of a specific adjustment for BGE's regulatory lag.

Mr. VanderHeyden testified that the results of Staff's and BGE's DCF results were very similar and that the difference in final ROE recommendation stemmed mainly from Mr. McKenzie's use of ECAPM instead of CAPM, and his use of a risk premium method based on awarded returns.[661] Additionally, Mr. McKenzie added 10 basis points for flotation costs and 30 basis points to reduce regulatory lag. In response to BGE's position that Staff had not addressed regulatory lag, Mr. VanderHeyden testified that the

[661] VanderHeyden Surrebuttal at 11-12.

Commission has already approved programs that improve regulatory lag, such as BGE's ERI, and that "an explicit upward adjustment is not necessary."[662] Additionally, Mr. VanderHeyden observed that in the past the Commission has rejected ROE adjustments related to current market conditions due to BGE's rapid filing of rate cases.[663] Mr. VanderHeyden further stated that the case has not been made that BGE is unique with regard to other utilities and regulatory lag. "The delay between investment and recovery is a known circumstance in regulated industries and is an expected characteristic of regulated utility investment."[664]

Staff witness Ward filed Surrebuttal testimony defending her elimination of two low-end DCF ROEs. She also stated that she corrected her DCF analysis in response to Mr. McKenzie's Rebuttal Testimony regarding the appropriate year to measure the dividend yield, but her change did not affect her final recommended ROE for BGE's gas distribution of 9.60.[665] Despite Dr. Woolridge's criticism, Ms. Ward defended her use of a historical market return to calculate CAPM. Finally, Ms. Ward explained that she chose her recommended ROE from the lower end of her range of reasonableness, due to an adjustment she made to account for the risk reducing effects of STRIDE.[666] Ms. Ward testified that STRIDE provides a very specific cost recovery mechanism that allows BGE to recover carrying costs in real-time, unlike the traditional rate making processes where the carrying costs are carried by the utility until the regulatory asset is put into rate base.

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662 VanderHeyden Surrebuttal at 18.
663 VanderHeyden Surrebuttal at 18, citing Case 9299, *Re Baltimore Gas and Electric Company,* 104 MD PSC 64, 102 (2013).
664 VanderHeyden Surrebuttal at 19.
665 Ward Surrebuttal at 4.
666 Ward Surrebuttal at 7.

She testified that this mechanism provides significant risk reduction to BGE that is unlike mechanisms used by other utilities in BGE's proxy group.

Commission Decision

Staff witness Cross observed that pursuant to regulatory principles, regulated utilities are allowed the opportunity to recover the costs of prudently incurred debt financing and to earn a return on equity financing. The total rate at which utilities are allowed to recover financing costs is referred to as the rate of return, which in turn is determined by summing the products of the long-term debt, short-term debt, preferred stock, and common equity.[667]

No party in this proceeding disputed the proposed costs of short-term debt, long-term debt, or preference stock proposed by the Company, leaving as the only issue before us the appropriate return on equity. Witnesses for BGE, Staff, and OPC presented markedly different recommendations regarding the appropriate ROEs for the Company's electric and gas operations.[668]

The Supreme Court set forth the fundamental elements for determining a fair return on the investments of a regulated utility in the cases *Bluefield Waterwork* and *Hope Natural Gas*.[669]

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[667] Cross Direct at 13.

[668] Even though BGE in fact has no publicly traded common stock and Exelon Corporation is the Company's only shareholder (McKenzie Direct at 32), we find it appropriate to continue our policy of determining separate returns on equity for BGE's electric operations and gas distribution services. That decision is consistent with our past precedent. *See* Case No. 9230, finding "gas and electric services are separable on the Company's books, and have different financing needs." Case No. 9230, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base Rates,* 102 MD PSC 74, 104 (2011).

[669] *Bluefield Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 693 (1923) ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties."); and *Fed. Power Comm'n v. Hope Natural Gas*

In those cases, the Court found that a return on equity should be: (i) comparable to returns investors expect to earn on investments of similar risk; (ii) sufficient to assure confidence in the company's financial integrity; and (iii) adequate to maintain and support the company's credit and to attract capital.[670] After having reviewed and considered the witnesses' testimony in view of the *Bluefield* and *Hope* decisions, we find that an ROE of 9.75% for BGE's electric operations and 9.65% for BGE's gas distribution services are fair and appropriate returns.

We start our discussion by observing that the witnesses used different methodologies and assumptions to estimate BGE's cost of equity. That is not a criticism. As Company witness Mr. McKenzie explained, the cost of common equity "cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed."[671] The determination of a fair ROE therefore requires a degree of discretion from the cost of capital expert. For example, he or she must choose which model or models to employ, how to assemble the most representative proxy group, and whether or how to exclude outliers from the analysis, to name just a few of the parameters. As OPC witness Dr. Woolridge explained, "estimating the cost of equity capital requires a degree of subjectivity in a number of areas, including the selection of models, the inputs for the models, and the measurement of the inputs for the model."[672]

Co., 320 U.S. 591, 603 (1944) ("the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

[670] *See* Woolridge Direct at 2-3 and McKenzie Direct at 5.

[671] McKenzie Direct at 33.

[672] Woolridge Surrebuttal at 19.

The ROE witnesses used various analyses to estimate the appropriate return on equity for BGE's electric and gas distribution operations, including the DCF model, the IRR/DCF, the traditional CAPM, the ECAPM, and risk premium methodologies. Although the witnesses argued strongly over the correctness of their competing analyses, we are not willing to rule that there can be only one correct method for calculating an ROE. Neither will we eliminate any particular methodology as unworthy of basing a decision.[673] The subject is far too complex to reduce to a single mathematical formula.[674] That conclusion is made apparent, in practice, by the fact that the expert witnesses used discretion to eliminate outlier returns that they testified were too high or too low to be considered reasonable, even when using their own preferred methodologies.

The ROEs we approve for BGE's electric and gas distribution operations are consistent with what we have approved in recent years. In Case No. 9299, decided on February 22, 2013, the Commission issued an order approving an ROE of 9.75% for BGE's electric utility operations and 9.60% for BGE's gas distribution operations.[675] BGE filed its next rate case promptly on May 17, 2013, initiating Case No. 9326. In that proceeding, decided on December 13, 2013, the Commission approved the same ROEs for the Company's electric and gas operations.[676] The Commission reasoned that BGE was a "low-risk investment" based upon its status as a monopoly provider of electric and gas distribution service, its lack of ownership of any generating facilities, and its stable

[673] For example, although we agree with Staff that BGE's risk premium analysis is somewhat circular (since it considers the ROEs issued by other state regulators), we find the analysis helpful in determining a just and reasonable return.
[674] This decision is consistent with our prior precedent, where we stated: "We find all of these analytical tools helpful and will not rely on any one to the exclusion of the others in making our decision." Case No. 9326, Order No. 86060 at 76.
[675] Case No. 9299, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates*, 104 MD PSC 64, 98 and 102 (2013).
[676] Case No. 9326, *Re Baltimore Gas and Electric Company*, 104 MD PSC 653, 695 (2013).

service territory with a BSA mechanism.[677] The Commission also found that the "low interest environment" provided BGE with "ample opportunity to obtain necessary capital at reasonable rates."[678] BGE's most recent rate case prior to the current proceeding was Case No. 9355, filed on July 2, 2014. That case resulted in a "black box" settlement among the parties to the proceeding, with many rate-specific details left out of the settlement. Nevertheless, the settlement provided overall rates of return for the Company and stated that the costs of equity used to determine those rates of return were 9.75% for electric and 9.65% for gas.[679] The ROEs approved today are consistent with the returns granted in Case Nos. 9299, 9326 and 9355. Rate stability is an important ratemaking goal – for ratepayers and utilities alike.[680] As Mr. VanderHeyden testified regarding returns on equity, it is important that the Commission "make gradual changes, and otherwise encourage a regulatory environment that does not surprise investors with changes that impact them adversely."[681] We believe this decision supports those laudable goals.

Beyond the importance of rate stability, the record in this case does not support a dramatically different ROE. We find that BGE continues to constitute a low-risk investment. Its status as a monopoly provider of electric and gas distribution service in a stable service territory has not changed. The Company does not own generating

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[677] *Id.* at 694.. The BSA refers to BGE's Bill Stabilization Adjustment mechanism, which decouples sales of electricity from BGE's revenues. The mechanism produces risk mitigating benefits for the Company.
[678] *Id*.
[679] Case No. 9355, *Re Baltimore Gas and Electric Company*, 105 MD PSC 596, 602, n. 28 (2014).
[680] VanderHeyden Direct at 3.
[681] VanderHeyden Direct at 7.

facilities, which lowers its risk, and it enjoys other risk-reducing attributes such as the ERI initiative, the BSA decoupling mechanism, and the STRIDE surcharge.[682]

BGE has ample access to capital on good terms. Indeed, we find nothing in the record to support the notion that BGE has faced restricted or impaired access to capital under its existing rates of return. It is true that BGE's witnesses have warned of an impending storm of interest rate hikes.[683] Perhaps interest rates will increase in the future, but a sudden and dramatic increase in interest rates does not appear imminent.[684] For example, even though the Federal Reserve ended its Quantitative Easing III bond buying program in 2014, the country has not seen a significant increase in rates.[685] To the contrary, Dr. Woolridge demonstrated a slight decrease in interest rates in that timeframe and he provided compelling evidence that long-term interest rates will remain low for the foreseeable future.[686]

We decline BGE's request for a specific upward adjustment to its ROE to compensate for flotation costs. In BGE's last fully litigated rate case, we rejected BGE's request for flotation costs, reasoning that the Company had not presented any evidence

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[682] Staff witness Ward and BGE witness McKenzie disagreed over whether the risk-reducing STRIDE surcharge warranted the granting of a lower ROE. Ms. Ward recommended an ROE on the lower range of her range of reasonableness, while Mr. McKenzie argued that many other gas utilities (including those in the proxy groups) possess similar mechanisms that allow for the recovery of infrastructure replacement costs. We will not make a specific downward adjustment as a result of the STRIDE mechanism, but rather consider it among many of the other factors that demonstrate to us the reasonableness of a 9.65% ROE for BGE's gas distribution operations.

[683] *See* McKenzie Direct at 15.

[684] This is not the first time the Commission has heard from BGE the dire warning that interest rates were on the verge of a steep ascent. In Case No. 9299, we responded to that argument by stating: "Whether the historic low interest rates are the result of a sluggish economy gradually recovering from a devastating recession, or are the consequence of artificial government interference in financial markets as testified by [BGE's witness], or both, they are … current reality." Case No. 9299, 104 MD PSC at 102 (internal quotations omitted). Our finding in this proceeding is the same. A low interest environment is our current reality.

[685] Dr. Woolridge Direct at 6.

[686] Dr. Woolridge Direct at 18-20. Although Dr. Woolridge provided valuable testimony to the Commission, we found his ultimate ROE recommendations too low to constitute a just and reasonable return for the Company.

that it had incurred the costs and therefore did "not satisfy the known and measurable principle."[687] Staff witness VanderHeyden correctly observed that in cases where we have awarded an ROE adjustment for flotation costs, the utility was able to provide specific evidentiary support of actual costs incurred.[688] For example, in Case No. 9336, we granted Pepco's request, stating: "We have consistently awarded flotation costs based on the verifiable costs of issuing new stock."[689] That is not the case here, where BGE has merely presented argument that investors are entitled to an adjustment for flotation on an ongoing basis whether or not the Company actually incurs such costs. We reject that argument.[690]

We also deny BGE's request for a specific adjustment to counter the effects of attrition. We find BGE's arguments on this topic unpersuasive for several reasons. First, BGE's argument amounts to a thinly veiled attack on the Commission's long-standing practice of using a historic test year to determine just and reasonable rates. *See* McKenzie Direct at 7, stating investors are concerned about what can be expected in the future, "not what they might expect in theory if a historical test year were to repeat."[691] But this Commission has consistently regulated through a historic test year because it best balances the financial needs of the regulated utility with the interests of the ratepayers in efficient and cost-effective service. It is true that the test year is unlikely to repeat itself exactly. However, the use of the test year provides the utility with a powerful incentive to control costs going forward, so that it earns or even exceeds its

[687] Case No. 9326, 104 MD PSC at 695.
[688] VanderHeyden Surrebuttal at 17.
[689] Case No. 9336, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, 105 MD PSC 329, 370 (2014).
[690] *See* OPC Initial Brief at 55, n. 235, observing that "[t]he Commission has consistently rejected *theoretical* flotation costs." (Emphasis in original).
[691] McKenzie Direct at 7.

authorized ROE. To simply grant a utility all of its costs and disregard the test year would eviscerate that incentive.

Second, although BGE complains that it cannot earn its authorized return in an environment of rising costs, its implicit assumption that costs will always be rising is unpersuasive. BGE has spent a significant amount of ratepayer money improving the reliability of its distribution system in compliance with Commission regulations, and it has expended considerable funds building new infrastructure through installation of the AMI system. Although those expenditures are important, there is no reason to believe that that level of infrastructure spending will continue indefinitely, or even accelerate as the Company seems to argue, such that the Commission must grant to BGE an elevated ROE that is adjusted upward for so-called regulatory lag. It is within BGE's power to control its spending and thereby earn its ROE.

Third, BGE's arguments suggest a right to a ***guaranteed*** return, an argument we reject. *See* McKenzie Direct at 9, stating in relation to his attrition argument: "Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation." It is not confiscatory to acknowledge that a regulated utility is not guaranteed a specific return. As Mr. VanderHeyden explained, the ROE is a specific calculation that is used at the time rates are set in a base rate case through the use of a historic test year.[692] The setting of an authorized ROE "does not represent an entitlement to a particular level of return over any period of time. Rates are not continuously recalculated to provide the awarded ROE."[693] In other words, in this State, rates are not based on a formula that raises and lowers revenue in order to

[692] VanderHeyden Direct at 2.
[693] VanderHeyden Direct at 2.

ensure the utility that it achieves its awarded ROE. Instead, in the interest of rate stability, rates are fixed with each case. And just as importantly, the "utility's earnings are variable based on the success of management in controlling costs and operating conditions."[694]

Finally, we deny BGE's attrition argument because the Company has filed cases on a very frequent basis. To the extent costs increase, including the surge in interest rates predicted by BGE witnesses, the Company may file a new rate case to address the changed environment.[695] In that regard, we look to our decision in Case No. 9299, where we stated: "Especially given BGE's recent predilection for filing rate cases frequently with the Commission, we see no value in awarding an anomalously high ROE during a time of historic low interest rates because of the risk that interest rates could increase several years in the future." [696]

In conclusion, we find that a return on equity of 9.75% for BGE's electric operations and 9.65% for BGE's gas distribution services complies with the standards established by *Hope* and

Bluefield. Those returns are comparable to returns investors expect to earn on investments of similar risk, as demonstrated through the use of the witnesses' proxy groups. They are sufficient to assure confidence in BGE's financial integrity, enabling the Company's investors to receive a fair return commensurate with risk. And the returns are adequate to maintain and support BGE's credit and to attract needed capital, as the

[694] VanderHeyden Direct at 3.
[695] *See* VanderHeyden Surrebuttal at 19: "BGE has filed rate cases on an almost annual schedule that allows the Company to rapidly increase rates in response to new investments. With this and other aspects of the rate setting process, there is no need to make an additional upward adjustment to BGE's ROE to reduce regulatory lag."
[696] 104 MD PSC at 102.

Company has successfully done with its existing returns. Given that BGE is a low-risk company, we are convinced that the returns authorized today will attract the necessary capital in the current low-interest rate environment to meet its statutory duty to provide safe and reliable service to its customers.[697]

2. ***Capital Structure***

Party Positions

BGE

In his Direct Testimony (submitted on November 6, 2015), Mr. Vahos projected BGE's capital structure as of November 30, 2015. On the electric side, he stated that BGE's capital structure would be: 39.1% long-term debt; 5.3% short-term debt; 3.7% preference stock; and 51.9% common equity.[698] He made the same projections for the gas side. From those calculations, he derived embedded cost rates and weighted costs for each category of capital, as reproduced below.

BGE's Requested Electric Rate of Return

	Capital Structure	Embedded Cost Rates	Weighted Cost
Long-term debt	39.1%	4.95%	1.94%
Short-term debt	5.3%	0.80%	0.04%
Preference stock	3.7%	7.02%	0.26%
Common Equity	51.9%	10.60%	5.50%
	100%		**7.74%**

[697] We were likewise unpersuaded by Dr. Woolridge that BGE's ROEs should be lower.
[698] Vahos Direct at 29.

BGE's Requested Gas Rate of Return

	Capital Structure	Embedded Cost Rates	Weighted Cost
Long-term debt	39.1%	4.95%	1.94%
Short-term debt	5.3%	0.80%	0.04%
Preference stock	3.7%	7.02%	0.26%
Common Equity	51.9%	10.50%	5.45%
	100%		**7.69%**

BGE requested an embedded cost rate of common equity for its electric business of 10.60% and an embedded cost rate of common equity for its gas business of 10.50%. Mr. Vahos requested that the Commission approve BGE's overall rate of return for electric of 7.74% and overall rate of return for gas of 7.69%.[699] Mr. Vahos observed that it is the Commission's practice to use the actual end of test year capital structure as the approved capital structure for the utility. Acknowledging that his November 6, 2015 testimony contained projections, he stated that BGE "will update this table with actual November 30, 2015 data when the results become available."[700]

On January 5, 2016, Mr. Vahos filed his Supplemental Testimony, which presented actual test year financial data for the twelve months ending November 30, 2015. One significant change in BGE's capital structure is the update in the common equity ratio from 51.9% to 53.7%. BGE's current requested capital structure is presented below:

BGE's Requested Electric Rate of Return

	Capital Structure	Embedded Cost Rates	Weighted Cost
Long-term debt	40.0%	4.95%	1.98%
Short-term debt	2.5%	0.44%	0.01%
Preference stock	3.8%	7.02%	0.27%
Common Equity	53.7%	10.60%	5.69%
	100%		**7.95%**

[699] Vahos Direct at 28-29.
[700] Vahos Direct at 28.

BGE's Requested Gas Rate of Return

	Capital Structure	Embedded Cost Rates	Weighted Cost
Long-term debt	40.0%	4.95%	1.98%
Short-term debt	2.5%	0.44%	0.01%
Preference stock	3.8%	7.02%	0.27%
Common Equity	53.7%	10.50%	5.64%
	100%		**7.90%**

Staff

Jason A. Cross, Regulatory Economist in the Commission's Division of Telecommunications, Gas and Water, provided testimony on behalf of Staff on BGE's capital structure. He stated that utilities operate in regulated environments where regulators must balance the interests of shareholders and ratepayers. One of the matters regulators must balance is the utility's debt equity ratio – a highly leveraged company faces a higher risk of default and can incur higher costs of debt, while a utility with a high percentage of equity becomes expensive for ratepayers. Mr. Cross warned that it is important for the regulator to scrutinize the relationship between the capital structures of the parent company and the utility to ensure that the financial integrity of the utility is not being compromised.[701]

Mr. Cross observed that on January 5, 2016, BGE updated its capital structure to reflect its actuals as of November 30, 2015. The updated capital structure moved upward from 51.9% to 53.7% common equity. Mr. Cross testified that "BGE's proposed capital structure is substantially more underleveraged than the capital structures recently approved for BGE by the Commission."[702] He emphasized that BGE's "equity-heavy capital structure continues a trend of increasing equity ratios in BGE's capital structure"

[701] Cross Direct at 14.
[702] Cross Direct at 16.

over the Company's last four rate cases.[703] Mr. Cross further testified that Staff conducted a trend analysis on BGE's common equity ratio over the 18 reporting quarters between June 2011 and September 2015 and found a statistically significant positive slope, demonstrating that BGE's equity position is increasing over time.[704]

Mr. Cross also testified regarding the detriments of high equity ratios. First, he testified that high common equity ratios may result in captive rate payers being burdened with higher rates, since common equity is the most expensive component of a utility's capital structure.[705] He observed, for example, that BGE's proposed equity cost on gas operations of 10.50% is more than two times the proposed cost of its long-term debt of 4.95%. Second, Mr. Cross warned that when a utility has a higher common equity position than its parent, the parent has the ability to shift the financial risk of the corporation onto ratepayers. Because credit agencies view the stability of a company as a whole, the parent company has an incentive to increase the utility's equity position (whose higher cost is paid for through ratepayers) in order to increase its own debt ratio without facing the attendant reduction in credit rating it would otherwise face.[706] Staff compared Exelon's long-term debt ratio compared to that of BGE over the last four reporting quarters and determined that the potential exists for indirect risk shifting from Exelon to BGE, given that Exelon is "substantially more leveraged than BGE."[707] Mr. Cross concluded that "[t]his consistent and substantial difference in leverage may be a

[703] Cross Direct at 16.
[704] Cross Direct at 17.
[705] Cross Direct at 19.
[706] Cross Direct at 20.
[707] Cross Direct at 20-21.

sign that Exelon is shifting some risk indirectly to BGE."[708]

Despite the trend, Mr. Cross did not conclude that the Commission should take action to reduce BGE's equity ratio, noting that the common equity ratios in Ms. Ward's proxy group were similar, with an average common equity ratio of 53.36%. Nevertheless, Mr. Cross advised that the Commission "monitor closely BGE's capital structure going forward to ensure ratepayers aren't unfairly burdened in the future."[709]

OPC

OPC witness Dr. Woolridge stated in his Direct Testimony that he would adopt BGE's initial capital structure, but with the caveat that BGE's relatively high equity ratio of 51.9% "presents a lower level of financial risk than the proxy group companies."[710] In particular, Dr. Woolridge observed that BGE's proposed capitalization of 51.9% has a higher common equity ratio (and therefore less financial risk) than the averages of the two proxy groups he used in his ROE analysis.[711] Dr. Woolridge also adopted BGE's recommended senior capital cost rates.

Party Responses

Mr. Vahos presented Rebuttal Testimony on behalf of BGE, stating that the Company's equity ratio in this proceeding is in line with its proxy group and that it is consistent with industry benchmarks.[712] Mr. McKenzie stated that BGE's proposed

[708] Cross Direct at 21.
[709] Cross Direct at 19.
[710] Woolridge Direct at 11.
[711] Woolridge Direct at 28.
[712] Vahos Rebuttal at 29.

capital structure, with 53.7% common equity, falls within the ranges of comparable gas distribution companies, as demonstrated in his gas proxy groups.[713]

In his Rebuttal Testimony, OPC's Dr. Woolridge opposed BGE's updated capital structure, proposed by the Company with its other updates for the test year. Dr. Woolridge testified that he would not adopt the updated capital structure due to its excessive common equity ratio of 53.70%, which he noted is about five percentage points higher than the averages of his two proxy groups.[714] Specifically, Dr. Woolridge stated that the median common equity ratios of his electric and gas proxy groups are 48.6% and 47.9%, respectively. Dr. Woolridge also argued that Staff witnesses VanderHeyden and Ward erred in accepting BGE's updated capital structure without conducting any study to determine if it was appropriate for electric utility or gas distribution companies.

In his Surrebuttal Testimony, Company witness Vahos stated that BGE's actual equity ratio of 53.7% is consistent with the equity ratios of the proxy groups used by BGE witness McKenzie in determining BGE's appropriate ROE. He also cited past decisions that reflect the Commission's preference for utilizing a utility's actual end-of test year capital structure in determining the appropriate capital structure in base rate cases.[715] Mr. Vahos further argued that the primary reason BGE's equity ratio has increased in recent years is because it was required to comply with the ring-fencing requirements provided in Commission Order No. 84698 in Case No. 9271 (the Exelon-

[713] McKenzie Rebuttal at 22.
[714] Dr. Woolridge Rebuttal at 2.
[715] Vahos Surrebuttal at 2-3. He cites Case Nos. 9230, 9299, and 9326, where BGE's actual test year ending capital structure was accepted by the Commission.

Constellation merger), which constrained BGE's ability to issue dividends.[716] BGE did not issue dividends between 2012 and 2014, which Mr. Vahos argued led to a higher equity ratio. Mr. Vahos argued that comparison of BGE's actual equity ratio to OPC's proxy groups is unreliable given the flawed methodology Dr. Woolridge used in picking the proxy groups. Finally, Mr. Vahos testified that the ring fencing provisions required by the Commission in Case Nos. 9173 and 9271 created distance between BGE and its parent company for purposes of credit rating separation, thereby mitigating the concerns articulated by OPC regarding cost shifting.[717]

Mr. Cross filed Surrebuttal Testimony opposing OPC's recommendation to utilize BGE's equity ratio as filed in the Company's original Application. Mr. Cross testified that the Commission's preference has been to utilize the actual equity ratio absent evidence that the ratio would be unduly burdensome to ratepayers and that OPC has provided no such evidence.[718]

<u>Commission Decision</u>

BGE is correct that the Commission's practice is to utilize a utility's actual test-year-ending capital structure when determining its authorized rate of return in a base rate proceeding.[719] We have often stated: "It is our long-standing policy to base the utility's

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[716] Mr. Vahos explained that without the ability to pay a dividend, all of BGE's earnings were retained in equity, thereby increasing the Company's equity ratio over that time period. Nevertheless, BGE began issuing dividends again 2015. Vahos Surrebuttal at 5.
[717] Vahos Surrebuttal at 5-6.
[718] Cross Surrebuttal at 2-3.
[719] BGE Initial Brief at 53. *See also* Vahos Surrebuttal at 2-3, citing Case Nos. 9230, 9299, and 9326, where BGE's actual test year ending capital structure was accepted by the Commission.

return on its actual capital structure absent evidence that the actual capital structure would impose an undue burden on ratepayers."[720]

Nevertheless, the practice is not immutable. We have required the use of a capital structure other than the actual end-of-test year capital structure proposed by the company where the circumstances have warranted it, such as with regard to Washington Gas and Light ("WGL"). In Case No. 9104, WGL proposed a hypothetical capital structure with a common equity ratio of 56.02%. The Commission rejected the equity-heavy capital structure and approved instead WGL's year-end actual capital structure with a common equity ratio of 53.02%. (*See* Hearing Examiner's Proposed Order finding "the Company's percentage of common equity of 56.02 percent is too large and will burden ratepayers with excessive equity. … WGL has failed to meet its burden to justify such a large increase in the common equity percentage in its proposed capital structure."[721] In Case No. 9267, the Commission adopted WGL's actual capital structure over Staff's objection, but informed WGL that absent proactive measures to increase its leverage, it would consider reducing its common equity ratio for rate making purposes in future cases.[722] In Case No. 9322, WGL proposed a capital structure with a common equity ratio of 60.80%, which the Commission rejected as overly burdensome. The Commission held that "the cost imposed by WGL's high equity ratio is out of proportion

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[720] Case No. 9311, *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*, 104 MD PSC 292, 347 (2013).
[721] Case No. 9104, *In the Matter of the Application of Washington Gas Light Company for an Increase in Rates and Charges for Gas Service and to Implement a Performance-Based Rate Plan*, Oct. 5, 2005 Proposed Order of Hearing Examiner at 42.
[722] Case No. 9267, *In the Matter of the Application of the Washington Gas Light Company for Authority to Increase Its Existing Rates and Charges and to Revise Its Terms and Conditions for Gas Service,* Order No. 84475.

to that of other utilities" and imputed a capital structure of 53.02% common equity.[723] Part of the Commission's rationale for reducing WGL's common equity in that case was that WGL's non-regulated parent company "has been able to leverage much of its non-utility, competitive affiliate risk onto WGL and its ratepayers."[724] Additionally, the Commission observed that if WGL successfully reduced its equity ratio, "the award of a high equity ratio now would enable WGL to reap a windfall because its rates would be based on an excessive equity ratio that far exceeds [its] actual capital structure."[725] (Internal quotations omitted).

In the present case, BGE has significantly increased its equity ratio from 51.9%, as reported in Mr. Vahos' November 6, 2015 Direct Testimony, to 53.7%, as stated in his January 5, 2016 Supplemental Testimony.[726] We find troublesome the substantial increase of 180 basis points in slightly over two months, especially given the magnitude of infrastructure that the Company has moved into rate base in this proceeding. Mr. Cross testified on behalf of Staff that "BGE's proposed capital structure is substantially more underleveraged than the capital structures recently approved for BGE by the Commission."[727] He explained that the Company's "equity-heavy capital structure continues a trend of increasing equity ratios in BGE's capital structure" over the Company's last four rate cases. That trend is illustrated in the chart below.[728]

[723] Case No. 9322, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Its Existing Rates and Charges and to Revise Its Terms and Conditions for Gas Service*, Order No. 86013 at 9.
[724] Order No. 86013 at 11.
[725] Order No. 86013 at 11.
[726] Vahos Direct at 29.
[727] Cross Direct at 16.
[728] Cross Direct at 16.

Common Equity Ratios in Last Six BGE Rate Cases[729]

Case No.	Year	Common Equity Ratio
9036	2003	48.40
9230	2010	51.93
9299	2012	48.40
9326	2013	51.05
9355	2014	52.30
9406	2015	53.70

Moreover, Staff's trend analysis over 18 reporting quarters of BGE's common equity ratio demonstrates a statistically significant increase in BGE's equity position over time.[730]

At the time of filing of his Direct Testimony, Dr. Woolridge's position was that BGE's actual capital ratio of 51.9% should be accepted, with the caveat that BGE presented a lower level of financial risk than his proxy group companies. However, after reviewing Mr. Vahos' Supplemental Testimony with the substantial change in capital structure, he argued that BGE's equity ratio should be set at the number provided by the Company when it filed its Application.[731] He observed that BGE's proposed common equity ratio is approximately five percentage points higher than the averages of his two proxy groups.[732] In its Initial Brief, OPC further stated that the Company's equity ratio is outside the range authorized in Maryland's last several electric rate cases or the averages for other electric companies.[733]

Overly high equity ratios impose significant burdens on ratepayers. As Mr. Cross testified, high common equity ratios may result in captive rate payers being burdened with higher rates, since common equity is the most expensive component of a utility's

[729] From Cross Direct at 17.
[730] Cross Direct at 17.
[731] Woolridge Direct at 11.
[732] Dr. Woolridge Rebuttal at 2.
[733] OPC Initial Brief at 61, citing Tr. at 1468.

capital structure.[734] Clearly BGE's authorized 9.75% return for electric and 9.65% return for gas are substantially above BGE's long-term debt of 4.95%. Additionally, when a utility has a higher common equity position than its parent, the parent has the ability to shift the financial risk of the corporation onto ratepayers.[735] Indeed, the potential of risk shifting was a significant driver in the Commission's decision to disallow WGL's proposed capital structure in the proceedings cited above. In the present case, Staff found that the potential exists for indirect risk shifting from Exelon to BGE, given that Exelon is "substantially more leveraged than BGE."[736] We concur with Staff's observation. Additionally, during the hearing, Mr. Cross conducted calculations that revealed that the burden to ratepayers of accepting BGE's updated capital structure, rather than its original one, is in the range of $4.5 to $4.6 million.[737] We find that cost imposes an undue burden on ratepayers.

In defense of BGE's position, Mr. Vahos argued that the Company's equity ratio increased as a direct result of it compliance with Commission-mandated ring-fencing provisions, which the Commission required as part of its approval of the Exelon-Constellation merger.[738] Specifically, Mr. Vahos claimed that BGE's high equity ratio stemmed from merger conditions that prohibited the Company from issuing dividends between 2012 and 2014, thereby driving upward retained earnings. Nevertheless, Mr. Vahos' defense does not explain the sudden increase in the Company's common equity

[734] Cross Direct at 19.
[735] Cross Direct at 20.
[736] Cross Direct at 20-21. Mr. Cross concluded that "[t]his consistent and substantial difference in leverage may be a sign that Exelon is shifting some risk indirectly to BGE." *Id*. at 21.
[737] Tr. at 1488.
[738] Vahos Surrebuttal at 5. Commission Order No. 84698 in Case No. 9271 (the Exelon-Constellation merger) provided at page 113, Condition 31: "BGE to Retain Internally Generated Equity Through 2014: BGE will not pay a dividend on BGE's common shares through the end of 2014."

that was revealed to the Commission through his Supplemental Testimony, only about two months after the Company's initial Application. During that time, BGE was authorized to and did issue dividend payments.[739] Indeed, BGE was not prohibited from issuing dividends throughout all of calendar year 2015, which comprises ten months of the test year. If, as BGE implies, it is able to lower its equity ratio in the near future, the Company would be reaping a windfall because its rates would be based on an excessive equity ratio that exceeds its actual capital structure. Especially given the large amount of infrastructure the Company has placed into rate base in this proceeding, we find that result would be inequitable. Accordingly, we accept OPC's position that BGE's updated capital structure be rejected, and instead we adopt BGE's original capital structure which includes 51.9% common equity.

D. Cost of Service Studies (COSS)

The purpose of a cost of service study ("COSS") is to determine the costs a customer class, or in some cases a jurisdiction, imposes upon a company. Costs may be directly assigned or allocated based upon various allocation methodologies. Once costs are assigned, then class (and jurisdictional) rates of return can be developed, which are used to design customer rates. The Commission uses the results from cost of service studies ("COSSs") as a guide in developing appropriate customer class rates.

<u>Party Positions</u>

<u>BGE</u>

Company witness Greenberg presented BGE's Calendar Year 2014 Company Recommended Electric Actual Cost of Service Study Proformed ("ECOSS") and the

[739] Tr. at 161, 764, and 1317.

Calendar Year 2014 Company Recommended Gas Actual Cost of Service Study Proformed ("GCOSS"). He noted that the Company's Studies were adjusted: "to reflect the base rate increases agreed to in the Unanimous Stipulation and Settlement Agreement ("Settlement Agreement") in Case No. 9355, which was accepted by the Commission in Order No. 86757."[740] Additionally, the studies have been adjusted to reflect the impact of Smart Grid costs on 2014.[741]

Mr. Greenberg stated that the "overall objective of BGE's 2014 ECOSS and GCOSS is "to present a fair allocation of costs responsibility among the customers classes based on the contribution of each class to total system costs during calendar year 2014..."[742] He stated that information from the ECOSS and GCOSS provides (1) a framework to help determine how the total revenue requirement should be recovered from each rate schedule based upon the proposed base revenue increase, and (2) a guide to proper rate design of Delivery Prices, Demand Prices and monthly Customer Charges.[743] According to Mr. Greenberg, in an ECOSS and GCOSS system costs are identified by customer class through a three-step process: (1) Functionalization; (2) Classification; and (3) Allocation.[744]

Functionalization is the process of dividing rate base and expenses into components as they relate to the operation of the Company.[745] BGE functionalizes its electric delivery service assets and expenses as transmissionor distribution operations,

[740] Greenberg Direct at 2-3.
[741] *Id*.
[742] Greenberg Direct at 4.
[743] Greenberg Direct at 4-5.
[744] Greenberg Direct at 6.
[745] *Id*.

excluding electric supply costs from the ECOSS.[746] Electric transmission costs which are subject to the Federal Energy Regulatory Commission ("FERC") are not included in the ECOSS for the purpose of distribution service ratemaking before the Commission.[747] BGE functionalizes its gas delivery service assets and expenses as production, storage or distribution operations, excluding gas commodity costs from the GCOSS.[748]

Classification is the process of separating the gas and electric functionalized rate base and expenses into classifications that relate to how costs are caused.[749] For example, distribution-related costs are classified between demand and customer-related components whereas demand-related costs are driven by customer class coincident peak ("CP") or non-coincident peak ("NCP") demand levels; and customer-related costs are driven by the number and costs of customers connecting to the gas mains and/or electric transformer and the requirements for the utility to service those customers (i.e., metering, meter reading, account processing, and billing systems).[750] Occasionally, distribution costs are classified as energy-related due to their variable nature.[751]

The final step in the cost of service study is Allocation, "in which rate base and expenses in each of these classified cost categories are assigned to customer classes according to customer load impositions on the distribution system, customer classes according to customer load impositions on the distribution system, customer connection requirements, and/or customer usage."[752]

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[746] Greenberg Direct at 6.
[747] Greenberg Direct at 6.
[748] Greenberg Direct at 6.
[749] Greenberg Direct at 7.
[750] *Id*.
[751] *Id*.
[752] Greenberg Direct at 7.

Mr. Greenberg testified that the Company made two adjustments to the recommended ECOSS and GCOSS in this proceeding: (1) adjusted the distribution revenue in order to reflect the approved rates from Order No. 86757 in Case No. 9355 so that ECOSS and GCOSS reflect delivery, demand, and customer charges as if the most recently approved rates were in effect a full calendar year not just the last two weeks of December, and (2) adjusted the ECOSS and GCOSS so that BGE's Smart Grid Initiative are appropriately reflected in each class' relative rate of return.[753] Mr. Greenberg explained that in order to fairly allocate cost responsibility for the Smart Grid Initiative among customer classes, an adjustment is needed to both ECOSS and GCOSS to reverse the deferral of incremental Smart Grid related depreciation, amortization, return and property taxes that would otherwise have been reflected on the income statement in 2014.[754]

In addition to these changes, Mr. Greenberg testified that the 2014 ECOSS and GCOSS made one "notable change in methodology from the studies filed in the last rate case proceeding, Case No. 9355."[755] Specifically, in the Settlement Agreement in Case No. 9355, BGE agreed to provide in the next electric rate case "(1) a five (5) year comparison of annual systems class demand allocators and allocations; and (2) a study of how any trends or changes affect the relative rates of return of the various electric rate classes."[756] BGE conducted the study for electric demands as requested by the Commission and provided the results in Company Exhibit DEG-5. BGE voluntarily conducted the same study for gas and provided those results in Company Exhibit DEG.

[753] Greenberg Direct at 9. *See also* Greenberg Direct at 10.
[754] Greenberg Direct at 10
[755] Greenberg Direct at 11.
[756] Greenberg Direct at 11.

Based on the results of these studies, BGE decided to utilize in its recommended ECOSS and GCOSS demand allocators based upon the five-year average of the BGE customer class non-coincident peak demand (NCP) and coincident peak demand (CP). Mr. Greenberg asserted that use of the five-year average demand allocator along with the inclusion of the Smart Grid costs and the rates approved in Case No. 9355 have impacted the class relative rates of return (RROR) by moving certain classes towards the system average rate of return while moving others further away from the system average rate of return. Mr. Greenberg also testified that "use of the five year demand allocators has improved the returns of certain weather sensitive schedules that would have otherwise received a larger demand related costs allocation due to abnormally cold weather in 2014.[757] The charts below compare the Company's proposed 2014 ECOSS and GCOSS relative rates of return in this proceeding to the relative rates of return filed in Case No 9355.

[757] Greenberg Direct at 12.

Table 1. ECOSS and GCOSS Relative Rate of Returns
Pro Forma 2013 vs Pro Forma 2014

	ECOSS RROR	
Schedule	2013 Filed	2014 Proposed Uses 5-Year Demand Allocator Results
R	0.75	0.69
RL	1.26	0.85
G*	1.05	1.00
GS	2.25	2.23
GL	1.41	1.58
P	0.88	1.08
SL	1.59	1.97
PL	3.27	3.92
T	7.18	6.90
SYSTEM TOTAL	1.00	1.00

*includes Schedule GU

	GCOSS RROR	
Schedule	2013 Filed	2014 Proposed Uses 5-Year Demand Allocator Results
D	1.06	0.99
C	0.88	1.01
ISS	0.81	0.94
IS	0.90	1.15
PLG	7.88	8.79
SYSTEM TOTAL	1.00	1.00

Mr. Greenberg explained that the ECOSS was developed to allocate costs to individual classes and then "match" distribution revenues from each rate class with rate base and expenses allocated to the given class.[758] Mr. Greenberg emphasized the

[758] Greenberg Direct at 15.

importance of understanding NCP and CP when allocating ECOSS. He noted that "use of the NCP in the allocation of demand-related distribution investment is the generally accepted methodology in the ECOSS development"[759] and that electric NCP demands for residential class are typically driven by weather sensitive house cooling load, which generally occurs during the summer months.[760] In 2014 the residential NCP occurred during January due to the extremely cold winter weather. [761] The NCP winter peak indicates that the residential demand is driven by electric resistance heating load whereas, historically, the residential NCP has been driven by summer cooling load.

The GCOSS is developed to allocate costs to individual classes and the "match base revenues derived from each rate class with rate base and expenses allocated to the given class.[762] For GCOSS, demand-related costs are allocated to customer classes based on CP and NCP demands. The CP allocator is the firm class' contribution to the total firm service send out on the day of the year with the highest firm send out (January 7, 2014).[763] The NCP allocator is based on each class' (including Schedule IS and Schedule ISS) highest hourly demand.[764] In other words, it is the maximum hourly demand observed during the winter months of every class regardless of the hour or the day.[765] Each class's contribution to the NCP is calculated by dividing that class' maximum hourly demand during the winter months by the sum of every class' maximum hourly demand.[766]

[759] Greenberg Direct at 17.
[760] Greenberg Direct at 17.
[761] Greenberg Direct at 19.
[762] Greenberg Direct at 19.
[763] Greenberg Direct at 31.
[764] Greenberg Direct at 32.
[765] Greenberg Direct at 32-33.
[766] Greenberg Direct at 33.

For ECOSS, all Smart Grid costs are classified as customer-related, assigned the CUST370DIR allocator and are allocated to customer classes based upon corresponding smart meter replacement costs. For the 2014 ECOSS, the Company used smart metering data in the determination of demand measures (CP and NCP) in the Schedules R, RL G, GS and GL customer classes.[767] For GCOSS, all Smart Grid costs are classified as customer-related, assigned the CUST381DIR allocator and allocated to customer classes based upon corresponding smart metering device replacement costs.[768] In GCOSS, Smart Grid costs are allocated to Schedule D and Schedule C.[769]

Mr. Greenberg noted that given the penetration of smart metering devices in 2014, there is no longer a need for traditional sampling methods for these classes due to the large volume of Smart Grid data points.[770]

In the ECOSS, the Company measures residential customer peak kW demand (Schedule R, Schedule RL) in aggregate on an hourly basis. Similarly, the Company measured all small commercial customer peak demand (Schedule G and Schedule GS) in aggregate on an hourly basis and the individual peaks for these schedules are determined at the time of the total small commercial peak.

Under the Company's recommended ECOSS and GCOSS, the customer class rate base dollar allocations and the corresponding class rate of return ratios to system average return are depicted in the charts below.

[767] Greenberg Direct at 25.
[768] Greenberg Direct at 31.
[769] Greenberg Direct at 31.
[770] Greenberg Direct at 25. *See also* Greenberg at 33.

Table 2. Comparison of Rate Base Dollar allocation and Class Rate of Return Ratios for 2014 Recommended ECOSS and GCOSS

	2014 ECOSS	
Schedule	Rate Base	RROR
R	1,565.2	0.69
RL	128.8	0.85
G*	292.8	1.00
GS	9.8	2.23
GL	565.2	1.58
P	203.7	1.08
SL	66.0	1.97
PL	25.6	3.92
T	2.1	6.90
SYSTEM TOTAL	2,859.2	1.00

*includes Schedule GU

	2014 GCOSS	
Schedule	Rate Base	RROR
D	737.7	0.99
C	300.9	1.01
ISS	6.1	0.94
IS	60.6	1.15
PLG	0.03	8.79
SYSTEM TOTAL	1,105.3	1.00

OPC

OPC witness Wallach argued that "contrary to the cost causation principles, the ECOSS does not allocate Smart Grid Initiative costs to customer classes commensurate with the allocation of Smart Grid benefits to those classes."[771] Therefore, he indicated that the ECOSS over allocates Smart Grid costs to the R and RL classes. Mr. Wallach contends that given that Smart Grid costs represent the bulk of the Company's requested revenue requirement increase, it would not be reasonable to allocate the requested

[771] OPC Initial Brief at 67 citing Wallach Direct at 22-23.

increase on the basis of the ECOSS. Rather he recommended that the revenue increase be allocated along the rate classes, except for Schedule T and Schedule PL classes, in proportion to each class's base distribution revenues under current rates.[772]

Mr. Wallach noted that BGE's Smart Grid Initiative was a discretionary program and the Company justified its spending on the Smart Grid Initiative in Case No. 9208 primarily on the basis of the economic benefits that would result from the Smart Grid investment. Specifically, in Case No. 9208, the Company argued that "despite the very significant cost of this proposed initiative, the benefits to customers are several times greater, conservatively estimated by BGE to be $2.6 billion over the life of the project, along with considerable additional benefits to reliability, service quality, and environmental objectives."[773] Since the primary driver behind BGE incurring the Smart Grid costs were the purported benefits that would be brought to customers, Mr. Wallach testified that "the equitable allocation would be one where each customer class's allocation of Smart Grid costs would be no more than that class's share of the system-wide benefits."[774] Mr. Wallach explained that the approach of allocating Smart Grid costs commensurate with benefits is consistent with NARUC definition of cost causation.[775]

Mr. Wallach suggested that because BGE did not incorporate a reasonable analysis of the forecasted economic benefits from the Smart Grid in the cost allocations, he developed a simplified allocation approach to the residential class of the operational and market benefits claimed by the Company for 2014.

[772] OPC Initial Brief at 67 citing Wallach Direct at 11.
[773] OPC Initial Brief at 67-68.
[774] Wallach Surrebuttal at 4.
[775] OPC Initial Brief at 68.

Mr. Wallach proposed to "allocate all of the avoided capacity and energy-conversation benefits to the residential class"[776] and "for all other operational or market benefits, he estimated the residential class's share of 2014 savings using appropriate allocators from the 2014 ECOSS."[777] Based on his approach, Mr. Wallach estimated that about 66% of 2014 operational and market benefits will flow to residential customers[778] which are substantially less than the share of the Smart Grid costs allocated to the residential class in BGE's 2014 ECOSS which is 81%.[779] Therefore, Mr. Wallach strongly argues that the Commission should reject the BGE's proposed allocation of the requested revenue increase to the residential class. "Instead, the revenue increase authorized by the Commission should be allocated among all rate classes except for Schedule T and PL classes in proportion to each class's base distribution revenues[780] under the current rates."

Staff

Staff witnesses Norman and Cross presented testimony on the Company's 2014 ECOSS and GCOSS. For the ECOSS, Ms. Norman does not support the Commission adopting the proposed five-year average demand allocator at this time. She testified that in Case No. 9355 the data was requested based on concerns expressed in an earlier proceeding that changes in RROR of the classes may be the result of shifts in load responsibility among the classes and the Commission may need a regulatory policy on

[776] OPC Initial Brief at 69.
[777] OPC Initial Brief at 69.
[778] OPC Initial Brief at 69.
[779] OPC Initial Brief at 70.
[780] OPC Initial Brief at 70.

how cost responsibility is established in the face of declining demand.[781] According to Ms. Norman the study of the five-year average demand allocators was requested to provide understanding of “the drivers of changes in demand across customer classes and the subsequent impact on allocation of costs.”[782] Ms. Norman contends that while the five-year study is informative there are no clear trends that are readily identifiable in the five year data provided.[783] Mr. Cross concurs with Ms. Norman’s assessment of the applying the five-year study for 2014 GCOSS. Neither Staff witnesses Norman nor Cross endorsed the use of the five-year average demand allocator at this time. Specifically, Ms. Norman explained during cross examination that “We don’t have a clear understanding of what’s driving those changes in demand. They [BGE] didn’t perform that analysis…[sic] we don’t know what’s being smoothed out here and how relevant it is to changes that the company might have in their cost in the test year as opposed to previous years. And absent that knowledge we’re reluctant to change at this time”[784] For these reasons, Staff recommended adoption of the RROR shown in the charts below for BGE 2014 ECOSS and GCOSS.

[781] Staff Brief at 56.
[782] Staff Brief at 56.
[783] Staff Brief at 56.
[784] Staff Brief at 57.

Table 3. Staff Recommended ECOSS and GCOSS Relative Rate of Returns[785]

Schedule	2014 Staff Recommended ECOSS 1-Year Demand Allocator
R	0.67
RL	0.65
G*	1.15
GS	1.53
GL	1.64
P	1.08
SL	1.95
PL	3.78
T	6.93
SYSTEM TOTAL	1.00

*includes Schedule GU

Schedule	2014 Staff Recommended GCOSS 1-Year Demand Allocator
D	0.96
C	1.02
ISS	1.33
IS	1.35
PLG	10.49
SYSTEM TOTAL	1.00

MEG

MEG witness Baudino did not oppose BGE's use of the five year average allocation factors in its 2014 ECOSS and GCOSS.[786] Mr. Baudino did note that since Company witness Greenberg testified that using the five-year average NCP and CP allocators for the ECOSS and GCOSS "provide for an appropriate allocation of demand-

[785] *See* Norman Direct at 19 and Cross Direct at 9.
[786] Baudino Direct at 5.

driven costs that incorporate demand patterns over a long time horizon" the five year study may provide the Commission with helpful information when used in conjunction with the standard one year study.[787] Mr. Baudino proposed that the Commission direct BGE to continue to provide the five year study and the year-by-year comparisons in future rate cases for both ECOSS and GCOSS.[788]

Commission Decision

The Commission uses cost of service studies *as a guide* in developing customer class rates. The Company presented both a 2014 Recommended ECOSS and GCOSS, which incorporated a five-year average demand allocator for determining the relative rates of return for each class. Additionally, the Company's 2014 Recommended ECOSS and GCOSS adjusted the ECOSS and GCOSS so that BGE's Smart Grid Initiative costs are appropriately reflected in each class' relative rate of return.

Staff opposed adoption of the five-year average demand allocator at this time because there is simply not enough evidence to determine what may be driving the changes in demand and because "the study does not address trends in peak demand across classes overtime in sufficient detail to allow Staff to recommend adopting the averaged allocator."[789] MEG did not oppose use of the five-year average demand allocator study and agreed that the information may be useful when used in conjunction with the one-year study. Therefore, MEG requested that the Commission direct BGE to continue to

[787] Baudino Direct at 5 and 19.
[788] OPC Brief at 11.
[789] Staff Brief at 57

provide the five year study and the year-by-year comparisons in future rate cases for both ECOSS and GCOSS.[790]

Based upon the record we find that BGE has not provided sufficient evidence for us to abandon the traditional one-year demand allocator study for the proposed five-year demand allocator study. Therefore, we adopt Staff's recommended RROR based on the traditional one-year allocator study and direct BGE to continue to provide the five-year demand allocator study for both electric and gas in future rate cases.

Second, we note that OPC's witness Wallach offers a benefits approach for allocating the Smart Gird Initiative costs among rate classes. According to Mr. Wallach, by allocating the Smart Grid costs on the basis of traditional cost causation principles rather than on the basis of expected benefits, the ECOSS over-allocates costs to the residential class. While there may be some merit to this approach, the Commission agrees with Staff witness Norman that "an approach based on benefits is not viable in this proceeding given the lack of information."[791] Nonetheless, with a more detailed analysis of the benefits approach allocation of costs between rate classes, we may consider utilizing it in future rate cases.

E. Rate Design

Rate design involves two functions: (1) the design of inter-class rates, which involves the assignment of the revenue requirement between the various customer classes, and (2) the design of intra-class rates, which involves the manner in which the class revenue requirement will be collected from customers. In order to determine how

[790] OPC Brief at 11.
[791] Staff Brief at 60.

much of any rate increase (or decrease) should be assigned to a particular customer rate class, we begin with the actual class rates of return reflected in the cost of service study ("COSS"). These results are then translated into a relative rate of return ("RROR"), which measures as a percentage the actual individual customer class rate of return compared to the utility's system average or overall rate of return.[792] A RROR of 1.0 signifies that a rate class has a return equal to the utility's overall rate of return. A RROR that is higher than 1.0 indicates that the class has a return (or contribution) that is greater than the system average and a RROR that is lower than 1.0 indicates a class return that is less than average. If all customer rate classes have a RROR of 1.0, then each class is contributing equally to the utility's overall rate of return based upon its cost of service. As a matter of policy, the Commission strives to bring all classes closer to a RROR of 1.0 in each rate case, to reflect the cost causation from each class. However, this goal is also tempered with notions of gradualism in order to avoid rate shock from the customers of any particular rate class.

Once the revenue requirement is apportioned among the various classes, intra-class rates may be designed. Almost all rate classes have a customer charge, which is designed to recover fixed utility costs, such as the cost of meters. Additionally, BGE customers have an energy charge, which is designed to recover variable costs. Finally, some non-residential customers have a demand charge, which is designed to recover capacity costs. Intra-class rate design is guided by important policy considerations,

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[792] *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to Its Electric and Gas Base Rates*, Case No. 9326, 104 Md. P.S.C. 653, 699 (2013).

including gradualism, energy conservation, economic impacts, as well as cost causation.[793]

In this case, BGE proposes significant increases in fixed monthly customer charges and proposes higher than average allocations of cost among various customer classes. The Company asserts that the installation of smart metering devices for residential and small commercial customers has effectively eliminated any difference between the costs to serve residential electric customers under Schedules R and RL and small commercial customers under Schedules G[794] and GS.[795] As a result, under BGE's rate design proposals in this case, the bulk of the Company's proposed rate increases for electric and for gas customers would be borne by residential and small commercial customers.

For reasons that will be discussed in greater detail below, we reject: the Company's proposed 37.5 percent increase in the Schedule R (residential) customer charge; the Company's proposed 34.3 percent increase in the Schedule G (small commercial) customer charge; and the Company's proposed 13.3 percent increase in the Schedule D (residential gas) customer charge. Also, by rejecting the Company's proposal to adjust customer class relative rates of return (RRORs) using five-year average cost of service data, and accepting Staff's RROR adjustments – which are based on Commission precedent – we further moderate the impact of the allocation of the Company's electric and revenue increases on all customers.

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[793] *Id.*
[794] Schedule G includes Primary (GP) and Unmetered (GU) services.
[795] BGE Initial Brief at 69. BGE recognizes that the Commission has been reluctant to approve large changes in customer charges in the past, but insists that now that the Company is attempting to recover the costs of Smart Grid (which BGE asserts is "largely customer-related in nature") it is appropriate to take a larger step in aligning customer charges with actual costs. BGE Reply Brief at 72.

OPC notes, and we agree, that contrary to cost-causation principles, the ECOSS does not allocate Smart Grid Initiative costs to customer classes commensurate with the allocation of Smart Grid benefits to those classes.[796] Therefore, we allocate the revenue increase authorized in this case among all rate classes, except Schedules T and PL, in proportion to each class's base distribution revenues under current rates.[797] We turn now to address specific inter- and intra-class revenue allocation adjustments.

1. ***Electric and Gas Customer Charge Adjustments***

BGE

BGE witness Frain proposed that certain residential and commercial class customer charges be increased – based on the results of the Company's 2014 electric and gas cost of service studies (ECOSS and GCOSS), including the impact of the deployment of smart metering devices.[798] According to Mr. Frain, at present – except for electric rate Schedules PL and PLG – the rate schedules for all customer classes include a volumetric component that covers a significant amount of the distribution portion of the customer bill.[799] He adds that while a significant portion of the costs supporting both the electric and gas distribution systems are demand-related, only a few customer schedules

[796] *See* OPC Initial Brief at 67. The ECOSS over-allocates Smart Grid costs to the R and RL rate classes. *Id.*
[797] MEG questioned whether the Commission has ever allocated the costs of specific investments based on benefits. Tr. at 1359. However, Mr. Wallach commented further that to the extent that the driver of a "discretionary investment" were the expected benefits, then the costs associated with that investment should be allocated "commensurate with" the expected benefits. *Id.* at 1361, 1371. He insists that what caused the smart grid costs to be incurred by BGE were "the expectation of benefits" and those benefits (he opines) are shared by customer classes other than the classes which have smart meters installed in their premises or on their locations. *Id.*
[798] BGE Ex. 18, Frain Direct at 7.
[799] *Id.* at 9. (At present approximately 80 percent of residential electric customers' fixed costs and approximately 65 percent of residential gas customers' fixed cost are recovered through volumetric charges; much higher, he submits, than the ECOSS and GCOSS support being recovered through volumetric rates.) *Id.*

(typically those customers with high usage) actually have demand elements in their rate design.[800]

He opines that increasing the customer charges for residential and small commercial electric and gas customers, as BGE proposes, would not substantially affect the current price signals to these customers (the price signals that encourage or discourage energy efficiency).[801] According to witness Frain, the customer charge adjustments proposed by BGE in this case shift (on average) 3 percent of residential electric customers' costs from variable commodity costs to fixed charges. Residential gas customers' fixed charges increase by 1 percent as compared with current rates and by 3 percent based on new rates, without the proposed increased customer charge.[802]

The Company proposes to achieve its customer charges adjustments by increasing the fixed customer charges for Schedules R and G to the level of Schedules RL and GS respectively, and increasing the fixed customer charge for the Schedule D gas rate class.[803] Specifically, the Company proposes to increase residential and small commercial electric and gas customers: Electric Schedule R from $7.50 to $12.00; Electric Schedule G from $11.50 to $17.50; and Gas Schedule D from $13.00 to $15.00.

Under BGE's proposal, residential electric customers' customer charge would increase $4.50 per month, residential gas customers' customer charge would increase $3.00 per month. The Company also proposes increasing the customer charge for

[800] *Id.* at 9. Most residential and small commercial meters, Mr. Frain noted, have not historically measured demand. *Id.*
[801] *Id.* According to witness Frain, "even if the entire distribution portion of the bill was a fixed charge, the customer would still receive appropriate price signals to encourage energy efficiency through their commodity savings; [noting that] approximately 70 percent of am average residential electric customer's bill was commodity-related and approximately 30 percent was distribution-related in 2014." *Id.*
[802] *Id.* at 12 (Table 1).
[803] *Id.* at 13.

Schedule G, a schedule that serves small commercial customers, from $11.50 per month to $17.50 per month. Witness Frain nonetheless maintains that the bill impact of the Company's proposed customer charge increases is minimal.

According to Mr. Frain, the monthly bill impact for a Schedule R residential customer under the Company's proposal, using 930 kWh per month (on a weather normalized basis), would be about $0.33 more if the Company's proposed customer charge increase (and other ratemaking adjustments) is accepted.[804] Similarly, with respect to residential gas customers, Mr. Frain testifies that at a consumption level of 57 therms per month, "a Schedule D customer is economically indifferent" to the Company's proposed customer charge increase.[805]

In defense of the Company's proposed customer charge adjustments, witness Frain restates that under the Company's current rate structure, a large portion of these fixed costs are instead recovered through the variable charges on a customer's bill and that customers with higher than average usage are subsidizing the fixed costs of those customers with lower than average usage.[806] He insists that BGE's proposed customer charge increases should work towards reducing the intra-class inequities between the recovery of fixed and variable costs.[807] He concludes that the Company's proposal "improves intra-class equity while still balancing other goals of the rate design process, as well as energy efficiency objectives."[808]

[804] *Id.* at 14.
[805] *Id.* at 15.
[806] *Id.* at 16.
[807] *Id.*
[808] *Id.* at 17.

BGE witness Frain testified that the proposed allocation of BGE's requested electric revenue increase is based primarily upon the relative returns of each customer class calculated in the Calendar Year 2014 ECOSS.[809] Likewise, the rate design (allocation) for the proposed gas revenue increase is based primarily upon the relative returns of each customer class calculated in the Calendar Year 2014 GCOSS.[810]

According to BGE, the current functionalized customer component cost levels for certain electric and gas customer classes warrant an increase in the level of fixed customer charges.[811] Witness Frain emphasizes that this is demonstrated "especially in light of the Smart Grid costs now included in the customer component of the [ECOSS and GCOSS] studies."[812] Accordingly, he proposes to eliminate the difference in the fixed customer charges for Time-of-Use ("TOU") and non-TOU electric customer classes and increasing the fixed customer charge for the residential gas customer class.[813]

Staff

Staff witness Blaise recommends that the customer charge for BGE Schedule R be increased only from $7.50 to $7.90 per month. He notes that BGE's attempt to equalize both the customer and volumetric charges under Schedule R, particularly with significant proposed increase in the residential-customer customer charge, does not comport with principles of gradualism and the energy policy goals instituted under EmPOWER MD.[814] Limiting the residential-customer customer charge increase to $0.40

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[809] *Id.* at 2-3.
[810] *Id.* at 3. Both studies were developed as discussed in the testimony of BGE witness Greenberg.
[811] *Id.*
[812] *Id.*
[813] BGE witness Frain estimates that there are about 55,000 TOU customers remaining on the BGE system. Tr. at 553.
[814] Staff Ex. 44, Blaise Direct at 2.

per month, and instead capturing the incremental increase in volumetric charges, witness Blaise concludes is "fair to the Company, [and] consistent with the principles of gradualism."[815] Staff urges that this approach provides customers more control over their bills and promotes policy goals of energy efficiency as outlined in the EmPOWER Maryland Act.[816]

Witness Blaise also proposed a slight increase in the Schedule G customer charge, allowing BGE to collect $0.071 in customer charge revenue for every dollar the Company collects in volumetric charges, proposing to increase the Schedule G customer charge from $12.50 to $12.64.[817] Staff also proposed increasing the Schedule GS customer charge from $17.50 to $19.23.[818]

In response to BGE's proposed gas customer charge adjustment, Staff witness Pongsiri opposed increasing the Schedule D customer charge from $13.00 to $15.00. Instead, he recommends an increase to $14.00, representing a 7.7 percent increase in the gas Schedule D customer charge – as compared to the Company's proposed 15.4 percent increase.[819] Based on a sensitivity study of the impact of customer charges on low-income customer bills, Mr. Pongsiri's testimony suggests that his recommended increase in the customer charge from $13.00 to $14.00 as compared to BGE's proposal to increase

[815] *Id.*
[816] *Id.* at 17. Staff also notes that increasing the Schedule R customer charge to $12.00 as BGE proposes, would move BGE's residential electric service customer charges to the highest among Maryland utilities. Tr. at 515-517.
[817] *Id.* at 16. Increasing the customer charge by 9.9 percent. Staff notes that not only does BGE propose to increase Schedule R and G customer charges, the Company also proposed increases to the volumetric charge for Schedules R and RL. Staff calculates that, if approved, the Company's proposed rate adjustments to these customer classes would lead to the collection of 88.1 percent of the total allocation of the new revenue proposes by BGE being assessed to these classes. Staff Ex. 44 at 9; Staff Initial Brief at 67.
[818] Staff Ex. 44, Blaise Direct at 17.
[819] Staff Ex. 31, Pongsiri Direct at 10-11.

the Schedule D customer charge to $15.00 results in an average savings of $0.17 per month (assuming customer consumption remains unchanged).[820]

OPC

OPC opposes BGE's proposal to increase the Schedule R customer charge from $7.50 to $12.00, and instead recommends an adjustment that would increase the Schedule R customer charge by the same percentage increase in revenues allocated to Schedule R.[821] OPC strongly protests that the Company's proposed increase in the residential customer charge would "dampen price signals to consumers" with respect to reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, "and exacerbate the subsidization of larger residential customer's costs by … low-usage customers.[822]

The Company did not propose customer charge adjustments for any of its large commercial and industrial electric and gas customers, therefore neither MEG nor DOD/FEA commented on this issue.

Commission Decision

The Company proposes to increase various class customer charges. OPC opposed BGE's proposed sharp increase in the residential customer charge, and Staff recommended only a nominal increase. The present composition of the Company's

[820] *Id.* at 14. (During the hearing, Mr. Pongsiri allowed that a Schedule D customer charge of $13.50 would also be acceptable to Staff. Tr. at 1648.)
[821] OPC Initial Brief at 70. (OPC insists that BGE's proposal would unreasonably shift costs to the customer charge that are more appropriately recovered through energy charges. *Id.*)
[822] OPC Ex. 23, Wallach Direct at 3-4. Mr. Wallach estimated that as much as 66 percent of the costs of BGE's smart meter initiative is being applied to the residential class, but opined that those costs should not be run through the Company's COSS. Tr. at 1367. He insists that regardless the allocator, the output is incorrect because the input costs are too high to begin with. *Id.* at 1368. (He argues that the Commission should not rely on the COSS to allocate smart grid costs, but instead allocate the Company's revenue increase in the same percentage amount to all classes. *Id.* at 1368.)

customer charges includes: administrative costs (such as billing and customer care), gas and electric meter costs, gas regulator costs, and the costs associated with the electric service connection from the transformer to the meter.[823] Witness Frain testified that while BGE's current customer charges for the residential electric and gas classes and the small commercial electric classes recover a portion of the fixed costs incurred in serving customers, they are not set at a level to recover all of the fixed costs.[824] He further insists that since fixed costs also have increased as a result of the deployment of smart metering devices, it is also reasonable to move the current customer charges towards the level supported in the 2014 ECOSS and GCOSS.[825] OPC notes, however, that the ECOSS over-allocates smart grid costs to Schedules R and RL, and thus overstates the contribution of smart grid costs to the fixed costs that serve the residential class.[826] Not all of BGE's AMI investments are fixed costs.

2. ***Electric Customer Charges***

Based on the record in this case, we find that residential customer charges should be increased at this time only nominally, as recommended by Staff. We accept Staff's proposal of $0.40 increase to $7.90 per month. Staff's proposed increase will not significantly change the proportion of revenue derived from the customer charge, which is currently 19.4 percent of Schedule R revenues.[827]

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[823] BGE Ex. 18, Frain Direct at 11.
[824] *Id.*
[825] *Id* at 11; *See* BGE Reply Brief – Table 3 at 71.
[826] OPC Initial Brief at 71.
[827] Staff Direct, Blaise at 14. (Under Staff's proposal, the bill impact of a $0.40 increase in the Schedule R customer charge is estimated to be about 3.7 percent. *Id.* at 13. According to Mr. Frain, the overall RROR increase proposed by the Company for Schedule R would evidence as about a 5 percent increase in the customer's total bill. Tr. at 558.

The large increase proposed by BGE raises concerns related to the Commission's principles of gradualism. In this case, BGE proposes a 60 percent increase in the Schedule R customer charge but only a 6.3 percent increase in the volumetric charge.[828] Under Staff's proposal, the bill impact of a $0.40 increase in the Schedule R customer charge is estimated to be about 3.7 percent, and according to Mr. Frain, the overall RROR increase proposed by the Company for Schedule R would result in about a 5 percent increase in the customer's total bill.[829] *Id.* at 558. We find that limiting the Schedule R customer charge to $7.90, which according to Staff amounts to a 3.7 percent increase, keeps the customer charge within the 5 percent proportionality that BGE proposes for all of its RROR adjustments. Therefore, we reject BGE's proposal to substantially increase residential and non-residential customer charges.

We find that a modest increase in the Schedule G customer from $11.50 to $12.10, which is slightly below Staff's proposal, but consistent with the Company's 5 percent overall RROR adjustments is reasonable and supported by the record in this case. In adjusting the Schedule G customer charge, we note that Schedule G serves small commercial customers, which in many ways are similar to residential customers. This decision, with respect to Schedule R and Schedule G customer charges will afford residential and small commercial customers a better opportunity to control their monthly

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[828] Tr. at 549. Mr. Frain responds that by comparing average residential customer bills with and without the Company's proposed increase in the Schedule R customer charge, Exhibit JCF-1 shows only a $0.34 difference in the average bill. *Id.* at 550. Even though the Company is proposing to increase the Schedule R customer charge from $7.50 to $12.00, the average Schedule R customer would not see a $4.50 increase in his monthly bill, *per se*. *Id.*

[829] *Id.* at 558.

bills by controlling their energy usage. Our decision, in this case, is consistent with EmPOWER Maryland goals and with our decision in BGE's last base rate case.[830]

Staff also proposed increasing the Schedule G (and GP) monthly customer charge from $11.50 to $12.64 and increasing the Schedule GS customer charge from $17.50 to $19.23.[831] On the basis of symmetry and in recognition of the principle of gradualism, for the reasons limiting the Schedule G (and GP) customer charge to $12.10, in proportion to the overall RROR adjustments that we adopt in this case. For Schedule GS we approve an increase in the customer charge for this rate schedule to $18.40, consistent with the proportional increase for other electric customer charge adjustments adopted in this case. Accordingly, we approve electric customer charge adjustments as follows:

Table 1: Electric Schedule Customer Charge Adjustments[832]

Customer Class	Current	Approved
Schedule R	$ 7.50	**$ 7.90**
Schedule G	$11.50	**$12.10**
Schedule GP (Primary)	$11.50	**$12.10**
Electric – Schedule GS	$17.50	**$18.40**

3. ***Residential-Schedule D Gas Customer Charge***

We reject BGE's proposal to increase Schedule D customer charge from $13.00 to $15.00 and determine that there should no increase in the customer charge for this schedule, leaving it at the current $13.00 per month charge. We note that the unlike the Schedule R (residential electric) customer charge, the Schedule D (residential gas)

[830] No proposal was presented to increase or decrease the customer charge associated with Schedule GS.
[831] Staff Ex. 44, Blaise at 17.
[832] The customer charges for rate schedules RL, GS, GU, GL (Secondary), GL (Primary), P and T remain unchanged.

customer charge was increased in at the Company's request in 2005, and more recently gas customers are also paying fixed monthly STRIDE charges.[833] In Case No. 9036, we allowed a modest increase in the Schedule D customer charge based on Staff's observation at that time that residential customer costs were decreasing. However, in this case we believe that holding the line on gas customer charges during the rate-effective period for this case will permit gas customers to have better control of their gas bills, allowing them the opportunity to wisely manage their gas usage. This decision is also in keeping the Commission precedent.

4. <u>Allocation of Electric Revenue Increase</u>

<u>BGE</u>

BGE proposes apportioning any revenue increase authorized by the Commission in this case such that each customer class' relative rate of return ("RROR") moves toward or within +/- 10 percent around the system average rate of return.[834]

In applying step-one of the "two-step" process adopted in Case Nos. 9299 and 9326, BGE witness Frain proposes moving Schedule R to a RROR of 0.90 and Schedule RL also to a RROR of 0.90. With the exception of Schedule T, the Company does not propose decreasing the class revenue contributions of the classes that are over-earning (or over-contributing) by more than 10 percent of the system average rate of return.[835] According to witness Greenberg's ECOSS analysis, Schedule T customers contribute a 6.90 RROR towards the system average rate of return. Witness Frain notes in his

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[833] In 2005. BGE proposed increasing the Schedule D customer charge from $12.35 to $13.25. The Commission approved an increase in the Schedule D customer charge to $13.00. *Re Baltimore Gas and Electric Company*, Case No. 9036, 96 Md. P.S.C. 334, 369 (2005).
[834] BGE Ex. 18, Frain Direct at 18.
[835] *Id.*

testimony that in Case No. 9326 the Commission reduced Schedule T's revenue by 10 percent in recognition of its "continued" disproportionately high RROR.[836] Here, BGE proposes reducing Schedule T revenues by 25 percent in step one.[837]

BGE proposes allocating all remaining revenue in proportion to the adjusted test year base distribution revenues, with the exception of Schedules PL and T (whose current RRORs are already 3.92 and 6.90 respectively).[838] The upward movement of the Schedule R RROR from 0.69 to 0.90 and the Schedule RL RROR from 0.85 to 0.90 results in an unadjusted step-one allocation of 28 percent (or $38.5 million) of the total revenue increase to the Schedule R and RL customer classes.[839] The step-two proportional allocation of the rate increase to all classes with the exception of Schedules PL and T result in an additional unadjusted increase to Schedule R and RL customers.[840] Witness Frain notes that the Delivery Service Charge in each rate schedule increases corresponding to the inclusion of "eligible costs".[841]

Staff

Staff recommends the Commission-approved two-step methodology for allocating revenues.[842] In step-one, Mr. Blaise allocates 17 percent of the Company's new revenues toward Schedules R and RL (which he notes are BGE's under-earning rate classes). Then, in step-two, he proposes distributing the remaining revenue among all classes

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[836] *Id.* at 19.
[837] *Id.*; BGE Initial Brief at 66.
[838] *Id.* The Company's combined step-one and step-two adjustments are shown in witness Frain's Table 5.
[839] *Id.* at 21.
[840] *See*, BGE Ex. 18, Frain Direct at 23. (Exhibit JCF-8 contains the breakdown of costs, by rate schedule, that the Company proposes adding to rate base and their associated revenues).
[841] *Id.*
[842] The two-step approach to rate design was upheld by the Commission in *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in Its Electric and Gas Base Rates* (Case No. 9230).

except Schedules SL, PL and T.[843] He urges that his proposed allocation approach moves all classes closer to the system's RROR in a gradual way.[844] He selected 17 percent for step-one as the "optimal allocation" of the new revenue requirement to avoid rate shock and for fairness to ratepayers. This selection, Mr. Blaise notes also helps increase the RROR of the under-earning classes and reduces cross-subsidization without causing rate shock.[845] Staff also notes that the upward movement of the Schedule R RROR from 0.69 to 0.90 represents a greater than 50 percent increase in the Schedule R RROR.[846]

Staff witness Norman testifies that the Company's ECOSS is consistent in methods and results with those submitted and relied upon in previous BGE rate cases. She supports the use of the ECOSS approach as a part of the ratemaking process in this case. However, she recommends reliance on the ECOSS results based on 2014 demand factors, consistent with previous cases, rather than the five year average demand allocators developed and used by BGE in this case.[847]

For gas rates, Staff witness Pongsiri's also calculated the Company's gas rate schedule RRORs using the Commission-approved two-step methodology. Mr. Pongsiri computed before and after RROR for BGE's gas rate schedules, after making "additional rate adjustments," based on Staff witnesses Norman and Cross, and relying on GCOSS results based on 2014 demand allocators – instead of the five-year average demand allocators proposed by BGE.[848]

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[843] Staff Ex. 44, Blaise at 9. Staff witness Blaise maintains that his rate design approach is aimed at addressing any potential issues of inter- and intra-class imbalances "while avoiding any disproportionate increase that would negatively impact the Company's customers." *Id.*
[844] *Id.*
[845] *Id.* at 10-11.
[846] Tr. at 523.
[847] Staff Ex. 34, Norman Direct at 3.
[848] Staff Ex. 31, Pongsiri Direct at 8-9.

According to witness Pongsiri, allocating a step one increase to Schedule D is problematic; Schedule D already accounts for 70 percent of base revenues, and receives 70 percent of the revenue increase through step two. A step one increase to Schedule D, witness Pongsiri opines would push the class RROR close to the system average but would be inconsistent with the principle of gradualism.[849]

5. ***Assignment of Electric Rate Increase by Schedule***

a. Schedules R and RL

BGE proposes to recover a significant portion (62 percent) of the proposed rate increase by increasing the customer charges for Schedule R customers.[850] The Company also proposes "aligning" the Delivery Service Charges for Schedules R and RL, which would also increase the current effective rates for those rate schedules once the remaining proposed revenue increase is allocated.[851] Witness Frain estimates that the Delivery Service Charge adjustment for Schedule R (residential electric) customers using (weather normalized) 930 kWh per month would increase the customer's total monthly bill by 5.8 percent (or $7.64) per month.[852]

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[849] *Id.* at 9. Additionally, Mr. Pongsiri opines that "if Schedule C is not allocated any of the recommended revenue increase in the first step, the RROR of Schedule C would drop from earning more than the system average to less than the system average." *Id.*

[850] BGE Ex. 18, Frain Direct at 23.

[851] *Id.* at 24. BGE Reply Brief at 70. (BGE insists that the limited increases recommended by Staff and OPC will only further increase the disconnect between the fixed costs to serve customers and the fixed rates the Company can charge them.)

[852] *Id.* Witness Frain maintains that he is proposing to align Schedule R and Schedule RL charges now that smart meters are being used to serve both types of customers. Tr. at 513-516, 552, 608.

b. Schedules G, GS and GU

BGE proposes to increase the customer charge from $11.50 to $17.50 for Schedule G customers.[853] As with Schedule R, the Company also proposes "aligning" the Delivery Service Charges for Schedules G (secondary service) and Schedule G (primary service), Schedule GS and for Schedule GU, which would also increase the current effective rates for those rate schedules once the remaining proposed revenue increase is allocated.[854]

c. *Schedule GL*

The Company proposes allocating 70 percent of the Schedule GL revenue increase to Demand Charge (increasing the Demand Charge from $3.69 per kW to $4.39 per kW, capturing $15.2 million of the proposed revenue increase for Schedule GL) and the remaining 30 percent to the Delivery Service Charge (increasing the Delivery Service Charge for secondary service from $0.01561 per kWh to $0.01866 per kWh, and increasing the Delivery Service Charge for primary service from $0.01614 per kWh to $0.01791 per kWh), generating $6.4 million in revenues.[855]

d. Schedules P and T and Schedule SL (Street Lighting)

The Company proposes recovering the entire proposed increase of $7.0 million in revenues from Schedule P customers by increasing the Demand Charge from $2.85 per kW to $4.28 per kW. Under Schedule T, the Company proposes to decrease the Delivery Service Charge from $0.00349 per kWh to $0.00300 per kWh.[856] BGE proposes an

[853] BGE Ex. 18, Frain Direct at 25.
[854] *Id.* at 25-26.
[855] *Id.* at 26-27.
[856] BGE Ex. 18, Frain Direct at 28.

increase the Schedule SL Delivery Service Charge from $0.00595 per lamp-watt to $0.00648 per lamp-watt, and recover the remaining revenue requirement for Schedule SL via proportionate increases in facilities charges (for cable, lamp fixtures and poles) as well as maintenance charges.[857]

Staff and OPC

Staff recommends that the Company's proposal to reduce revenue collection from Schedule T by 25 percent be rejected, and that Schedules T, PL and Schedule SL should not be allocated any new revenues.[858] OPC witness Wallach also opposes any new revenue allocation to Schedules T and PL, but supports allocation of some new revenue allocation to Schedule SL.[859] Although Staff accepts that Schedule T is technically over earning, witness Blaise anticipates that based on the frequency of BGE rate cases – given the current trajectory – he expect Schedule T will, at some point reach the level of the system average.[860] Mr. Blaise also noted that a number of considerations are involved in designing rates, including customer with high and low usage. Therefore, he kept the current billing determinants for the customer charge, demand charge and volumetric charge the same, and allocated the revenue distribution among each component rather than apply all of the new revenue to the demand portion of the bill.[861]

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[857] *Id.* at 29.
[858] Staff Ex. 44, Blaise Direct at 2.
[859] Generally, OPC witness Wallach recommends that smart grid costs be allocated based on the benefits to each rate class, but the analysis of whether each class benefits from smart grid, and to what extent, has not been performed. See Tr. at 212-213, Greenberg.
[860] Tr. at 2012. Given the frequency of rate cases, assuming no increases in the Schedule T revenue distribution, he anticipates that we will get to parity with the system within the next few years. *Id.*
[861] *Id.* He commented further that if the billing determinants are retained as is, the intra-class inequity will not be as severe as if all billing proportions were adapted to BGE's proposal. *Id.* at 2017-2018.

MEG

MEG supports BGE's proposed revenue allocation, including the Company's proposed 25 percent reduction to Schedule T and opposes Staff's proposal that would hold Schedule T's revenue allocation constant.[862] MEG also supports BGE's proposal to collect the entire Schedule P increased revenue requirement through the Schedule P demand charge, arguing that Staff's proposal to increase the Schedule P distribution charge 10.8 percent and the Schedule P demand charge 5.1 percent would send inaccurate price signals to Schedule P customer that energy is more expensive than it is.[863]

DOD/FEA

DOD/FEA supports BGE's recommendation to allocate 100 percent of any revenue requirement increase to the Schedule P demand charge.[864] DOD/FEA notes that large power users should have their costs align with the cost of service in order that those customers may more effectively navigate in an unbundled market.[865]

Staff Rebuttal

In Rebuttal, Mr. Blaise continues to oppose a BGE's proposed reduction in Schedule T revenues, because he asserts, "[his] allocation methodology gradually moves all rate schedules closer to the system's RROR."[866] Mr. Blaise opposes MEG's support of BGE's proposal with regard to Schedule P, and also opposes MEG witness Baudino's endorsement of BGE's rate design recommendation for Schedule T. He notes that, if

[862] MGE Ex. 1, Baudino Direct at 3; MEG Initial Brief at 4-5, 6; Tr. at 1396. He agreed, however, that if Schedule T rates were not reduced by 25 percent, as BGE proposes, "other things being equal" the RROR for Schedule T would tend to decline after rates went into effect for other classes. *Id.* at 1398.
[863] MEG Initial Brief at 7-8.
[864] DOD/FEA Initial Brief at 17.
[865] *Id.*
[866] Staff Ex. 45, Blaise Rebuttal at 2. Mr. Blaise's recommended electric rate design approach "decreases Schedule T's RROR to 4.47 from the current 6.93." *Id.*

accepted, BGE's proposal "will lead to intra-class inequities by disproportionately shifting a significant portion of the revenue burden onto the demand portion of the bill."[867]

Mr. Blaise agrees with OPC witness Wallach's opposition to new revenue allocation to Schedule T and PL; however, he opposes OPC's recommendation to distribute some new revenue to Schedule SL.[868]

Commission Decision

In considering rate design, regulators, including this Commission, counter-balance the principles of cost causation, gradualism, reasonableness and overall fairness to each rate class. We have also considered price-signaling, especially as certain rates may encourage or discourage energy conservation.

We are mindful of the competing interests of the various customer classes and the need to design rates in a fair and gradual manner. Consistent with our decision in BGE's last rate case in Order No. 86757, except for those classes that are significantly over-earning, the record in this case supports our continued use of the rate design process two-step process to allocate the Company's increased revenue requirements. In doing so, we adopt a gradual approach to allocating the electric revenue requirements adopted in this case. We believe a more gradual movement toward unity for these classes is best, and therefore in step-one we authorize Staff's recommend RRORs, based on adjustments to the Company's 2014 ECOSS.[869]

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[867] *Id.* at 3. Staff's proposal, Mr. Blaise urges, "slightly decreases the class revenue share of the demand charge, from 50 percent to 47.4 percent, and increases the volumetric charge from 46.1 percent to 48.5 percent." *Id.*

[868] *Id.*

[869] Staff Ex. 44, Blaise Direct at 9.

By taking this more gradual approach, we better align the RROR in step-one for electric rate Schedules R/EV and RL with the system average return. In step-one, Staff allocated 17 percent of its proposed revenue requirement increase to Schedules R and RL (the two under-earning classes). In step-two, Staff allocated the remaining revenue requirement increase among all the classes, except Schedules SL, PL and T.[870] Therefore, we adopt Staff's after step-two RRORs as follows:

Table 2: After Step-Two RRORs For Electric Rates

R/EV	RL	G/GU	GS	GL	P	T	SL	P
0.80	0.76	1.07	1.41	1.44	1.00	4.78	1.35	2.61

We conclude that this decision strikes an appropriate balance among the rate classes while bringing all classes closer to the system-wide rate of return. Acceptance of Staff's RRORs also strikes the appropriate balance between principles of cost causation and energy conservation.[871]

6. ***<u>Allocation of Gas Revenue Increase</u>***

As with allocating the proposed electric rate increase, BGE proposes apportioning any revenue increase authorized by the Commission in this case such that "each customer class' rate of return [relative rate of return ("RROR")] moves toward or within … +/- 10 percent around the system average rate of return."[872] Since all classes are either over-earning or already within +/- 10 percent of RROR, the Company does not propose a step-

[870] *Id.*
[871] *Cf. Re Potomac Electric Power Company* [Case No. 9286, Order No. 85028 at 130]; 103 Md. P.S.C. 293, 355.
[872] BGE Ex. 18, Frain Direct at 29.

one increase for any of its gas rate classes. The Company also does not propose decreasing for classes that are over-earing relative to the RROR.[873]

a. *Schedule D*

The Company proposes recovering $14.7 million of its proposed $54.6 million Schedule D gas rate revenue increase by increasing the Schedule D customer charge from $13.00 to $15.00.[874] The remainder would be recovered by increasing the Schedule D Delivery Price.[875]

b. *Schedule C*

Schedule C accounts for $19.2 million in gas revenues. The Company proposed different increases for the first block of service (the first 10,000 therms per month) and for the second block (all therms over 10,000 therm per month).[876]

c. *Schedule IS, ISS*

The Company proposes allocating 50 percent of the proposed revenue increase to the Schedule IS Demand Price and 50 percent to the Delivery Price. In order to do so, in the Company's case-in-chief, witness Frain proposed a Demand Price increase from $0.5301 per therm to $0.6865 per therm, and proposed a Delivery Price increase from $0.0460 per therm to $0.0520 per therm, resulting in a 32.1 percent increase in the demand price and a 11.7 percent increase in the delivery price.[877] In its case-in-chief, for

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[873] *Id.* at 30. Unlike electric Schedule T, gas Schedule PLG (which has a RROR of 8.79) also was not proposed to be reduced.
[874] *Id.* at 34.
[875] *Id.* In the Company's case-in-chief, witness Frain estimated that for a Schedule D customer using 57 therms per month, these rate adjustments will increase the total monthly bill by 11.3 percent or $7.56.
[876] *Id.* at 34-35. In the Company's case-in-chief, witness Frain proposed a first-block increase from $0.2938 to $0.3879 per therm. For the second block (all therms over 10,000 therm per month), BGE proposes to increase the current effective rate from $0.1428 per therm to $0.1940 per therm.
[877] BGE Exhibit JCF-4, Sheet G-5.

Schedule ISS, the Company proposed increasing the Demand Price from $0.7005 per therm to $0.8661 per therm, and proposes increasing the Delivery Price from $0.0872 per therm to $0.0935 per therm, resulting in a 23.4 percent increase in the demand price and a 13.3 percent increase in the delivery price.[878]

d. Schedule PLG

Unlike electric Schedule T, the RROR for gas Schedule PLG (8.79) is not proposed to be reduced. BGE notes that Gas Private Area Light (PLG) is a very small customer class that is closed to new customers. (It is, however, significantly over-earning). Witness Frain opines that not reducing the PLG's RROR serves as a "disincentive" to those customers to keep their "continuously-burning" gas lamps in service.[879]

Staff

For purposes of allocating increase in gas revenues, witness Pongsiri recommends allocating 3 percent of Staff's proposed revenue requirement to Schedule C; the remaining 97 percent of the revenue increase he recommends allocating in step two to all schedules except Schedule PLG.[880]

[878] *Id.* The per therm demand charge and per therm delivery charge reflect those included in the Company's case-in-chief, and not necessarily the rates adopted in this order. Optional Firm Delivery Service ("OFDS") and Distribution Interruption Penalty ("DIP") Prices are calculated based on an effective volumetric demand rate, based on the total class demand revenue and total class volumes. The Company proposes DIP prices, calculated by multiplying the first block OFDS Prices by 1.5, and the Excessive Use Interruption Penalty Prices – calculated by multiplying the proposed block OFDS Prices by 2. *Id.* at 36. See also, BGE Exhibit JCF-4, Sheet G-6.
[879] *Id.* at 37. Schedule PLG applies to a total of 14 customers.
[880] Staff Ex.31, Pongsiri Direct at 18.

MEG

With regard to the Company's proposed gas cost revenue allocation under Schedule IS, MEG submits that the Schedule IS is earning a class rate of return that falls outside the +/- 10 percent rate of return band, and therefore "should receive a lower than system average percentage revenue increase in this proceeding."[881] MEG recommends that the Commission reject BGE's proposed revenue allocation for Schedule IS, but adopt the Company's proposal to collect any approved revenue allocation for Schedules IS and ISS, by apportioning 50 percent to the demand charge and 50 percent to the delivery charge.[882]

Commission Decision

Consistent with our decision in BGE's last rate case in Order No. 86757, and with this decision with respect to electric rate design, except for those classes that are significantly over-earning, the record in this case supports our continued use of the rate design process two-step process to allocate the Company's increased revenue requirements. In doing so, as with the electric rate design, we adopt a gradual approach to allocating the gas revenue requirements adopted in this case. We believe a more gradual movement toward unity for these classes is best, and therefore in step-one we authorize a Staff's recommend RRORs, based on the Company's 2014 GCOSS.

By taking this more gradual approach, we better align the RROR in step-one for Schedules IS, ISS and PLG with the system average return. We conclude that this

[881] MGE Ex. 1, Baudino Direct at 4.
[882] MEG Initial Brief at 9.

decision strikes an appropriate balance among the rate classes while bringing all classes closer to the system-wide rate of return.

BGE does not propose allocating the increase in gas revenues to any class in step-one, because all classes are either over-earning or are already within the +/-10 percent band of the system average.[883] Staff witness Pongsiri notes, however, that Schedule D accounts for approximately 70 percent of gas rate base revenues, and thus receives 70 percent of the revenue increase that would generally be allocated in step-two.[884] He notes also that if no new revenues are allocated to Schedule C in step-one, the Schedule C RROR would drop below the 1.0 system average.[885] Therefore, Staff proposes allocating 3 percent of the Staff recommended gas revenue increase to Schedule C only. The remaining 97 percent is allocated to in step-two to all gas rate schedules, except Schedule PLG, based on the proportion of each class's share of total distribution revenues.[886] In doing so, Staff adopts a gradual allocation of the gas revenue requirements in this case. We find that this more gradual movement is best, and therefore we authorize Staff's recommend RRORs, based on adjustments to the Company's 2014 GCOSS. Therefore, we adopt Staff's after step-two RRORs as follows:

Table 2: After Step-Two RRORs For Gas Rates

D	C	ISS	IS	PLG
1.001	0.96	0.97	1.19	5.62

[883] Staff Ex.31 at 7.
[884] *Id.* Staff witness Pongsiri observes that while assigning a step-one increase to Schedule D would push the Schedule D class's RROR closer to the system average (from 0.96 to 1.001), this would lead to rates for the residential class that is inconsistent with the principle of gradualism. *Id.*
[885] *Id.*
[886] *Id.*

7. Rollover of Energy Efficiency Charges

BGE witnesses Case introduced the issue of the Company's proposed recovery of energy efficiency costs in base rates.[887] According to witness Case, at present the Company energy efficiency program costs are visible (or transparent) to customers, however, the benefits of these programs are "not easily determinable by a customer" and according to BGE "certainly not as visible as the EmPOWER MD surcharge on monthly bills."[888] Under the present construct, the Company contends that although the total customer bill is lower than it otherwise would be, the EmPOWER MD surcharge continues to grow. Moving reviewed and approved charges from the surcharge into base rates would lower the surcharge, and would eliminate what the Company characterizes as a "misleading" representation of the surcharge (which doesn't reflect the offsetting benefits of the programs).[889]

BGE witness Case also noted that disparity between the transparency of the costs and benefits of the utility efficiency programs was a topic addressed in the 2015 EmPOWER Maryland Work Group Summary Report – noting that participants had chosen not to propose more 2015-17 portfolio spending due to concerns about increasing charges on customer bills.[890] The Company proposes to move $218,315 in unamortized

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[887] BGE Ex. 28, Case Direct at 40. (The Company's proposal "that eligible costs currently being recovered through the electric and gas Energy Efficiency Charge for which actual spend has been reviewed and approved by the Commission be moved into base rates.")
[888] *Id.*
[889] *Id.* at 40-41.
[890] *Id.* at 41.

electric energy efficiency costs into rate base and $31,331 in unamortized gas energy efficiency costs into rate base for a total electric/gas rate base increase of $249,647.[891]

BGE witness Frain opined that the EmPOWER Maryland charge on a customer bill could be seen as misleading, as the surcharge itself only reflects costs and does not reflect the offsetting benefits of the programs.[892] In response, the Company proposed that, during each base rate case, eligible costs currently being recovered through the EmPOWER Maryland charges (Electric Rider 1 and Gas Rider 2) for which actual spend has been reviewed and approved by the Commission be moved from the EmPOWER Maryland charges into base rates.[893]

Staff

Staff witness Best opposes with BGE's proposal to move the through September 2014 eligible gas energy efficiency costs (currently recovered through Gas Rider 1) into base rates.[894] Ms. Best notes that as a line item surcharge brings awareness to the EmPOWER program. By having the charge listed on the bill, she notes a customer is informed that the EmPOWER program exists, which may prompt the ratepayer to participate.[895]

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[891] BGE Exhibit DMV-6 (Actual). The rate design – by customer class – allocation of the proposed energy efficiency-related base rate increase is set forth in BGE witness Frain's Exhibit JCF-8, for Electric Tariff Supplement 570 and Gas Tariff Supplement 412.

[892] BGE Initial Brief at 70; BGE Ex. 18, Frain Direct at 40.

[893] *Id.* In response to the Commission's concern about considering BGE's request outside of the EmPOWER Maryland process, in collaboration with the other utilities, Mr. Frain suggested that the Commission could make the decision in this case and apply the decision in other utility-specific cases as they occur. Tr. at 559.

[894] Staff Ex. 24, Best Direct at 2.

[895] *Id.* Under BGE's proposal, there would be no change in the cost recovered, but the surcharge itself would be lower. *Id.*

DOD/FEA

DOD/FEA witness Dr. Goins asserts that the Company should continue recovering its conservation program costs through the applicable energy efficiency riders and the EmPOWER Maryland charge.[896]

Commission Decision

Nearly all parties, including Staff, OPC and DOD/FEA oppose BGE's proposal to move recovery of energy efficiency costs into base rates by moving the current electric (Rider 1) and gas (Rider 2) surcharges into base rates. Staff notes that the Company's proposal for recovery of these costs is inconsistent with the EmPOWER Maryland cost recovery of other utilities.[897] OPC also asserted that acceptance of BGE's proposal would reduce transparency of the EmPOWER Maryland program.[898]

We agree with Staff, OPC and DOD/FEA that energy efficiency costs should continue to be reflected on customer bills and recovered through the established electric and gas) EmPOWER Maryland surcharges. We disagree that the EmPOWER Maryland surcharges are in any way seen as misleading, and have through our May 87575 EmPOWER Order, directed an EmPOWER work group to evaluate options to better reflect the benefits of EmPOWER programs.[899] Rather, we agree with Staff that the line

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[896] *Id.* at 16.

[897] Staff Initial Brief at 31. Staff emphasizes that uniformity in the treatment of the EmPOWER Maryland programs across all utilities whenever possible is preferable. *Id.*

[898] OPC Initial Brief at 73; OPC Ex. 26, Chang Direct at 29.

[899] Order No. 87575 (May 26, 2016) at 43-45 OR: *In the Matter of Potomac Edison Company d/b/a Allegheny Power's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Matter of Baltimore Gas and Electric Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Matter of Potomac Electric Power Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Matter of Delmarva Power and Light Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency*

item surcharge brings awareness to the EmPOWER Maryland program, encourages recognition of energy efficiency measures and may well prompt customers to participate in these programs, which advances the goals of the EmPOWER Maryland Act. Accordingly, the Company's energy efficiency costs shall continue to be reflected through the electric and gas surcharges, and the Company's proposal to move these costs into base rates is rejected.

8. 2016 Smart Energy Rewards (SER) and Smart Energy Manager (SEM) Costs

BGE intends to begin recovering prospective SER and SEM program cost through its 2016 EmPOWER MD charge.[900] However, the Company requests that electric Rider 2 and gas Rider 1 rates be revised to reflect recovery of SER and SEM program costs to be spent for the remainder of 2016, when new base rates become effective as the result of the Commission's decision in this case.[901] The Company proposes to begin recovering prospective SER and SEM costs annually through the Energy Efficiency Charge, with a subsequent rollover in to rate base of costs/expenditures that have been reviewed and approved by the Commission.[902] BGE intends to recover *between rate case-eligible*

Act of 2008, In the Matter of Southern Maryland Electric Cooperative, Inc.'s Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Washington Gas Light Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008 (Case Nos. 9153-9157, 9362; Order No. 87573, May 26, 2016) at 43-45.

[900] According to BGE witness Mark Case, "[f]rom 2013 through the summer of 2015, participating customers have earned approximately $28 million in BGE Smart Energy Rewards bill credits by reducing their energy usage on Energy Savings Days." BGE Ex. 28, Case Direct at 8. He notes also that "[t]he BGE Smart Energy Manager program has also been effective with participating customers expected to experience an average energy reduction of 1.4% in 2015." *Id.*

[901] BGE Ex. 18, Frain Supplemental Direct at 7. As with the roll over of energy efficiency costs, the Company maintains that this will more closely align the cost recovery from these programs with the associated benefits. *Id.* However, the Company will continue to defer SER and SEM costs into a regulatory asset as an incremental costs to deploy Smart Grid. *Id.*

[902] *Id.* at 8.

energy efficiency costs (including SER and SEM program costs) through electric Rider 2 and gas Rider 1.[903]

In its Initial Brief, BGE notes that no party in this proceeding has contested the Company's proposal to recover SER and SEM program costs starting in the rate-effective period through the EmPOWER Maryland Charges.[904] Therefore, the Company's proposal with respect to recover SER and SEM program costs for the rate-effective period through the EmPOWER Maryland charges is accepted.[905]

Based on the decisions set forth in this order, for average monthly usage of 925 kWh, the BGE residential electricity customer will experience an estimated $2.67 per month increase in electric distribution costs. For the BGE residential gas customer using an average of 57 therms per month, the monthly bill will increase $4.86 per month.

IT IS THEREFORE, this 3rd day of June, in the year Two Thousand Sixteen, by the Public Service Commission of Maryland,

ORDERED (1) That the Application of Baltimore Gas and Electric Company, filed November 6, 2015 (as supplemented by BGE over the course of this proceeding), seeking an increase in its electric distribution revenue requirement of $115.6 million and an increase in its gas distribution revenue requirement of $78.2 million, in addition to the creation of a rider to pass through the increased costs related to Baltimore

[903] *Id.* at 9.
[904] BGE Initial Brief at 72.
[905] However, as noted above we decline to have these charges rolled over into base rates.

City's conduit lease and maintenance fee, is hereby denied;

(2) That Baltimore Gas and Electric Company is hereby authorized to increase electric distribution rates by no more than $ 41.762 million and to increase gas distribution rates by no more than $47.776 million, for service rendered on or after June 4, 2016, consistent with the findings in this Order;

(3) That Baltimore Gas and Electric Company is directed to file tariffs in compliance with this Order with the effective dates prescribed herein, subject to acceptance by the Commission; and

(4) That all motions not granted herein are denied.

/s/ W. Kevin Hughes

/s/ Harold D. Williams

/s/ Anne E. Hoskins

/s/ Jeannette M. Mills

/s/ Michael T. Richard
Commissioners

Baltimore Gas and Electric Company
Case No. 9406
Electric Operations

Revenue Requirement
($000's)

Adjusted Rate Base	$2,915,925
Rate of Return	7.28%
Required Operating Income	$212,279
Adjusted Operating Income	$188,132
Operating Income Deficiency	$24,147
Conversion Factor	1.7295
Revenue Requirement	$41,762

Rate Base
($000's)

Per Books Balance	$2,924,893
Uncontested Adjustments	$64,413
Total Uncontested	$2,989,306
Contested Adjustments	
Average Balance of Smart Grid Regulatory Asset	$0
Cash Working Capital	($4,466)
Accumulated Deferred Income Taxes - Bonus Depreciation	($9,425)
Accrued Smart Grid Operational Savings	($9,643)
Smart Meter Installation Opt-Out Increased Costs, net of tax	($3,549)
Retired Legacy Meters	($46,495)
Case No. 9361 Merger Costs to Achieve Regulatory Asset	$197
Adjusted Rate Base	$2,915,925

Operating Income
($000's)

Per Books Balance	$243,155
Uncontested Adjustments	($64,633)
Uncontested Balance	$178,522
Contested Adjustments	
Defer and Amortize gains/losses on sale of Real Estate	($526)
Annualize Certain Regulatory Asset Amortization Periods revised in Case No. 9355	$177
Annualize AFC to Reflect Requested Returns	($92)
Annualize CVR Costs since Case No. 9355	($1,040)
Recover Exelon Business Service Company Compensation in OIA 11	$0
Amortize Smart Grid Regulatory Asset Deferrals Post-Test Year	$0
Tax Impact on Interest Synchronization	($2,177)
Amortize Smart Grid Regulatory Asset Over 10 years	$10,051
Accrued Smart Grid Operational Savings	$964
Smart Meter Installation Opt-Out Increased Costs Over 10 years	$710
Case No. 9361 Merger Synergies and Costs to Achieve Amortization	$1,543
Adjusted Operating Income	$188,132

Baltimore Gas and Electric Company
Case No. 9406
Gas Operations

Revenue Requirement
($000's)

Adjusted Rate Base	$1,225,250
Rate of Return	7.23%
Required Operating Income	$88,586
Adjusted Operating Income	$61,229
Operating Income Deficiency	$27,357
Conversion Factor	1.7464
Revenue Requirement	$47,776

Rate Base
($000's)

Per Books Balance	$1,181,626
Uncontested Adjustments	$55,051
Total Uncontested	$1,236,677
Contested Adjustments	
Average Balance of Smart Grid Regulatory Asset	$0
Cash Working Capital	($218)
Accumulated Deferred Income Taxes - Bonus Depreciation	($3,061)
Accrued Smart Grid Operational Savings	($4,639)
Smart Meter Installation Opt-Out Increased Costs, net of tax	($1,401)
Retired Legacy Meters	($2,193)
Case No. 9361 Merger Costs to Achieve Regulatory Asset	$85
Adjusted Rate Base	$1,225,250

Operating Income
($000's)

Per Books Balance	$77,680
Uncontested Adjustments	($23,004)
Uncontested Balance	$54,676
Contested Adjustments	
Annualize AFC to Reflect Requested Returns	($81)
Recover Exelon Business Service Company Compensation in OIA 11	$0
Amortize Smart Grid Regulatory Asset Deferrals Post-Test Year	$0
Tax Impact on Interest Synchronization	$18
Riverside Remediation Accrual	$1,193
Amortize Smart Grid Regulatory Asset Over 10 years	$4,019
Accrued Smart Grid Operational Savings	$464
Smart Meter Installation Opt-Out Increased Costs Over 10 years	$280
Case No. 9361 Merger Synergies and Costs to Achieve Amortization	$660
Adjusted Operating Income	$61,229

Concurring Statement Of
Commissioner Harold D. Williams and
Commissioner Anne E. Hoskins

We join in the Commission's Order in Case 9406,[1] but write separately to elaborate and clarify our views on two issues: the proposed Baltimore City conduit fee increase; and the impact of this and previous rate increases on limited income customers.

First, it is our expectation that BGE and Baltimore City will redouble their efforts to work together to find the most cost-effective approach for rehabilitating the conduit system, which is essential for ensuring reliable electric service. When BGE returns to the Commission to seek cost recovery for its pro rata share of prudent, actual costs incurred by the City to operate and maintain the underground conduit system,[2] the cost recovery should be shared by all BGE ratepayers.[3] Just as this Commission has authorized rate increases from all ratepayers across the BGE territory to pay for other reliability-related infrastructure upgrades that provide geographically-focused benefits (notably STRIDE, Electric Reliability Initiative and Howard County reliability projects[4]), the cost of necessary reliability upgrades in electric delivery infrastructure in Baltimore City should

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[1] In a separate statement, Commissioner Williams dissents, in part, to Order No. 87591.
[2] In a court filing, Baltimore City acknowledged that "the City has a contractual obligation to reimburse BGE for conduit lease fee payments that are not spent on maintaining the conduit system." Norman Direct, CSN-18 (Memorandum of Law in Opposition to [BGE's] Motion for a Preliminary Injunction, filed November 25, 2015 at 26).
[3] An option to impose cost recovery solely on Baltimore City ratepayers ("Option A") is not supported by Commission precedent and practice. Footnote 464 in today's Order mistakenly relies on *In Re Baltimore Gas and Elec. Co.*, Case No. 8127, Order No. 68240 (1989), which actually reinforces the concerns raised by OPC and the City of Baltimore regarding assessing a subset of customers based on a decision made by their local government. The 1989 Order noted a previous Commission Order involving infrastructure upgrades in Annapolis that "rejected surcharging BG&E's Annapolis customers, because the City, not those customers, caused the cost to be incurred" and concluded that such "a surcharge would be an inequitably burdensome assessment on that group of ratepayers."
[4] *See* Case No. 9291 (Phase I and Phase II) (addressing complaint from Howard County and approving an investment plan to fortify feeders located only in Howard County, some of which were not in violation of RM43 standards or listed among BGE's "poorest performing feeders").

be borne by all BGE ratepayers. By the end of our hearings, only Commission Staff continued to support assessing Baltimore City customers through "Option A", but even they acknowledged that "regulators do not typically analyze or require locational cost estimates within utility territory, differentiating rates by only territory-wide class characteristics."[5] For example, BGE's significant expenses on tree trimming benefit residents in tree-lined suburbs much more so than residents who live in row houses in West Baltimore or commercial businesses on North Avenue, yet all ratepayers contribute to recovery of this reliability-based expense. A key strength of our electric system is that it is universal -- it connects everyone and in doing so makes our society and economy much stronger. It is not only the customers who live or operate businesses in Baltimore who will suffer if the conduit system is not repaired,[6] but also those who commute to Baltimore for jobs and who visit the City for arts and culture and health care. Instead of pitting one set of customers against another, we urge participants in the regulatory process to work together to find cost-effective ways to modernize our energy infrastructure, making it safe, reliable and sustainable for all customers.

Our second concern relates to the disparate impact repeated rate increases is having on Maryland's limited-income customers. Over the past 3 years, the average residential BGE ratepayer's base distribution charges have increased $9.09 per month for

[5] Norman Direct at 31. *See* BGE Initial Brief at 43-44, which stated, "BGE believes that the Commission should authorize recovery through Option B." *See also* BGE witness Vahos' testimony where he agreed that Option B was "more reasonable" than Option A. Tr. 686 at 12-15. OPC and Baltimore City opposed Option A.

[6] If the Commission accepted BGE's original "Option A" proposal to recover the cost only from Baltimore City ratepayers, the average residential Baltimore City ratepayer would see a monthly bill increase of $8.75. Frain Direct at 39. This would be extremely burdensome for some of the poorest customers in Maryland.

electric service and $11.70 per month for gas service.[7] In addition, customers face additional infrastructure investment charges through STRIDE (for gas customers) and ERI riders. We have supported rate increases to the extent they have funded necessary upgrades in BGE's distribution network, including investments in a smarter grid which promise better service and a path to a more sustainable electric system (with opportunities for electric transportation, demand response, energy efficiency and distributed renewable energy). However, we are concerned that we are reaching a tipping point for many residents of limited income. While Maryland offers financial support programs, they are insufficiently funded, and serve less than one-third of income-qualified customers.[8] It is time for Maryland to consider new universal service models,[9] including legislation that clarifies the Commission's authority to consider ability to pay when allocating rate increases among and between rate classes. Without legislative and regulatory reform, we risk undermining the inherent strength of our electricity system: its ability to bring power and light to everyone.

/s/ Harold D. Williams

/s/ Anne E. Hoskins
Commissioners

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[7] Case No. 9299, Order No. 85374 (Feb. 2013): electric, $3.33; gas, $2.70.
Case No. 9326, Order No. 86060 (Dec. 2013): electric, $2.13; gas $0.73.
Case No. 9355, Order No. 86757 (Dec. 2014): electric, $0.96; gas $3.41.
Case No. 9406, Order No. 87591 (June 2016): electric, $2.67; gas $4.86.

[8] Office of People's Counsel, Comments on Office of Home Energy Program's Fiscal Year 2015 Annual Report on the Electric Universal Service Program at 2 (ML # 186418).

[9] *See, e.g.*, Pennsylvania's Customer Assistance Program (http://www.rhls.org/pa-utility-law-project/pa-low-income-utility-assistance-programs/) and the California Alternate Rates for Energy (CARE) Program (http://www.cpuc.ca.gov/General.aspx?id=976). *See also* Public Conference 27, Commission Staff's filing of the *Affordable Energy Plan*, November 1, 2012 (ML # 143460).

**Dissenting Statement, In Part, Of
Commissioner Harold D. Williams And
Commissioner Michael T. Richard**

While we fully support the decisions of our colleagues with regard to the majority of this order, we are unconvinced that AMI has been proven to be cost-effective. Consistent with Order Nos. 83410 and 83531, we agree with OPC and DOD that based on the evidence presented, ratepayers should not be required to pay in full at this time for these investments. As DOD observes, the Commission conditioned the approval of BGE's AMI case, requiring BGE to demonstrate that it has delivered the benefits that make the project cost effective. We also agree with DOD that "something is amiss" and we would be far more confident in AMI's effectiveness if we were discussing rate reductions rather than a rate hike. While the company may suggest that any challenge to its benefits-cost analysis amounts to "post hoc nickeling and diming," in Order No. 83531, the Commission found it important to note that these investments would undergo proper review. If the final systems fell short of being cost effective, the Commission would determine the cost recovery outcome that the public interest requires.

Although we agree with BGE that investing in new technologies can be beneficial, we fully expect, and our ratepayers deserve, that those investments be delivered as promised and provide meaningful bill savings for all customers.[1] We believe that OPC thoroughly and fairly evaluated BGE's AMI. They called attention to

[1] Order No. 83410 at 6. When the Commission approved BGE's second attempt at a smart meter case, the Commission further noted that it "'views cost-effectiveness as requiring a real rate of return of ratepayers' investment, measured by meaningful bill savings for all ratepayers,' and we do not view the outcomes of the TRC or other California Manual tests as dispositive or binding…'" Order No. 83531 at 31, n. 153, citing *In the Matter of Baltimore Gas and Electric Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPower Maryland Energy Efficiency Act of 2008*, Order No. 82384, Case No. 9154 (December 31, 2008) (quoting Commission Letter Order to BGE, Item No. 10, June 18, 2009 Administrative Meeting, Maillog No. 108061 (August 18, 2008)).

speculation and claimed benefits that in many cases did not necessarily rely on AMI or may have been achieved at lower costs. We agree with OPC and believe it was an error for BGE to not consider the treatment of legacy meters and the SER credit costs in their cost-effectiveness analysis. And we believe that OPC's "hold-harmless" approach would have more fairly allowed BGE to recover the 82 cents of each dollar spent for those tangible benefits OPC identified. Although this approach would still have resulted in a rate increase (albeit lower), it could have given BGE an incentive to continue to work to prove the AMI infrastructure performance and savings and therefore to seek future recovery on the $136 million in OPC's disallowed costs.

Unfortunately, the majority's decision will result in higher rates for ratepayers than we would have granted, including Maryland's most vulnerable residential customers, such as low-income households and the elderly. As anticipated in the dissents from Order Nos. 86200 and 87264, for those vulnerable ratepayers who exercised their right to opt out of having a smart meter installed, the result is even more impactful; they will be charged a higher distribution rate even after they pay a fee that disproportionately impacts them.[2]

While we do not agree with the majority's cost-effectiveness finding and advocated for OPC's "hold harmless" position, we do join in the decision to disallow $47.8 million in costs requested for AMI deployment – most notably the $16.6 million in costs attributable to customers' ability to opt-out of receiving a smart meter, agree that

[2] We further believe the Commission's decision in the instant case should reflect the same standard advocated in the dissent from Order No. 87264: "one that is 1) based on the evidence presented; and, 2) is most favorable for Maryland customers." Order No. 87264 at 3.

BGE's customer education efforts were flawed, and concur with our colleagues on all other AMI direction provided in the order.

Looking down the road, now that BGE, and other state utilities have developed, or are at various stages of developing AMI infrastructure, we hope to be convinced that smart meters are, in fact, cost-effective and beneficial to ratepayers. In the future, we would expect to see BGE and all utilities come to the Commission to offer rate reductions to offset the very real and very significant costs of AMI. We anticipate that the utilities will prove that AMI is the best and most cost-effective means to achieve savings that are noticeably greater than "what was possible pre-SGI deployment."[3] And in the future, it is our expectation that utilities will rely less on "rote" and theoretical calculations for AMI cost-effectiveness[4] and look for ways to establish new methodologies that demonstrate real and hard dollar savings to ratepayers from this costly statewide investment. We do not believe it is unreasonable for policymakers and Commissioners alike to be open to continuously challenge and update these tools which often have significant financial consequences to our citizens.

/s/ Harold D. Williams

/s/ Michael T. Richard
Commissioners

[3] DoD Reply Brief at 4.
[4] We agree with OPC, for example, that "[r]ote calculations of an 'avoided cost' number using a screening methodology that is applied to [an] entire suite of programs that encompass energy efficiency, conservation and demand side programs" do not constitute reliable evidence in determining cost-effectiveness. OPC Reply Brief at 8.

ALJ/SRT/lil **Date of Issuance 12/6/2021**

Decision 21-12-015 December 2, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	Rulemaking 20-11-003

PHASE 2 DECISION DIRECTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO TAKE ACTIONS TO PREPARE FOR POTENTIAL EXTREME WEATHER IN THE SUMMERS OF 2022 AND 2023

TABLE OF CONTENTS

Title **Page**

PHASE 2 DECISION DIRECTING PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY TO TAKE ACTIONS TO PREPARE FOR POTENTIAL EXTREME WEATHER IN THE SUMMERS OF 2022 AND 2023

Summary

This decision adopts several supply- and demand-side requirements to ensure there is adequate electric power in the event of extreme weather during times of greatest need in summers 2022 and 2023. Power outages in August 2020 triggered the opening of this proceeding, and while improvements have been made to increase supply and lower demand for electricity, concerns remain.

On July 30, 2021, Governor Newsom issued an Emergency Proclamation urging all state energy agencies to ensure there is adequate electricity to meet the needs of Californians in 2022. The Commission has conducted an analysis of the need for new resources and found that a range of 2,000 to 3,000 megawatts of new supply- and demand-side resources should help address grid reliability concerns in the most extreme circumstances in 2022 and 2023.

This decision adopts the following supply- and demand-side measures to help provide contingency resources to support the grid in an extreme weather event. Each of these measures will help fill the need for additional resources in 2022 and 2023.

- We adopt the following demand-side changes:
  - We expand on the Emergency Load Reduction Program (ELRP) adopted in Phase 1 of this proceeding;
  - We make modifications to the ELRP aimed to increase participation and provide clarity in guidance. Among these modifications, the compensation rate of ELRP is expanded to $2 per kilowatt hour;
  - We add an ELRP program that allows residential customers to receive compensation for reductions in energy use during system emergencies, with special

outreach to low-income customers and customers in Disadvantaged Communities;[1]

- o We expand on electric vehicle potential by allowing aggregation of vehicle to grid managed charging and discharge to support the grid at net peak;
- o We broaden the Flex Alert media campaign to focus on the new Residential ELRP program and continue existing activities into 2022 and 2023 and direct the media campaign to discourage the use of prohibited backup generators during ELRP events, working with the Commission's Energy Division on messaging strategy;
- o We make changes to existing Demand Response programs, both on a statewide basis and to individual programs that pertain to each major electric Investor-Owned Utility;
- o We allow the Investor-Owned Utilities to procure incremental Demand Response resources from third-party Demand Response Providers through bilateral contracts;
- o We approve a large smart thermostat incentive program designed to reduce air conditioning a few degrees during emergencies, with special protection for low-income customers that qualify for our California Alternate Rates for Energy or Family Electric Rate Assistance Programs; and
- o We add pilots to test the effectiveness of dynamic rates that change rapidly in response to grid emergencies.
- o We prohibit the use of backup generators to achieve incremental load reduction in the ELRP by

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[1] Pursuant to Section 39711 of the Health and Safety Code, Disadvantaged Communities are defined as (1) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation and (2) Areas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment. *See also* Health and Safety Code Section 116426.

non-residential participants located in Disadvantaged Communities.

- We adopt the following supply-side measures, among others, intended to enhance the availability of electric generation to serve load in summer 2022 and 2023:
  - We allow energy storage projects that are not fully deliverable as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023;
  - We expand use of a Central Procurement Entity as a means of procuring reliability resources located in local areas; and
  - We encourage accelerated online dates for procurement already ordered.

Two attachments are adopted. Attachment 1 provides an overview of the modifications the Commission is making to the demand side programs, with the exception of the ELRP. Attachment 2 outlines the modifications being made to the ELRP.

This proceeding is closed.

1. Background

In August 2020, California experienced a series of rolling blackouts caused by inadequate energy supply, an extreme heat wave, and market factors. This Commission (CPUC), California Independent System Operator (CAISO) and the California Energy Commission (CEC) issued a Root Cause Analysis of the reasons for the outages, and concluded that additional supply and demand measures were required to avoid a repeat of the 2020 experience in summer 2021.

In the months that followed, this Commission, the CEC and the CAISO took swift and aggressive action to improve near-term system reliability in time for Summer 2021. Among other things, we ordered procurement of new supply and demand side resources for summers 2021 and 2022; the CEC approved efficiency improvements at existing power plants to increase their generation capacity; and the CAISO implemented market changes to better reflect supply and demand during stressed hours. Despite record-breaking heat in California this past summer, which led to tight grid conditions on multiple occasions, we avoided rolling outages like the ones experienced in August 2020.

However, as we have all experienced firsthand, the acceleration of climate change continues to create extreme and unpredictable heat events, droughts, and wildfires across the West—all of which are more frequent and more intense and lead to added stress on our electric grid, especially during critical hours of the day. In 2021, an unprecedented series of heat waves gripped the entire West Coast of the United States, with parts of the States of Oregon and Washington experiencing significant heat waves. Over the past several summers, California's heat waves have started earlier in the year and lasted longer than in the past.

Meanwhile, the problem of catastrophic wildfire also affected much of the western United States, threatening distribution and transmission lines responsible for ensuring electric reliability in California. A third crisis – extended drought and significantly diminished reservoir water supply – placed significant limits on the amount of hydroelectric generation available up and down the West Coast. Coupled with these other changes, the increase in use of solar energy in California requires adaptation to ensure adequate electric supply remains after the sun sets each day to an even greater extent than previous modeling has suggested.

This perfect storm of reliability challenges requires urgent action now. The Commission must help ensure Californians have adequate energy supply and flexibility in energy demand to ensure energy reliability in summer 2022 and 2023. Our key concern is to ensure the availability of adequate supply, and reduction in electric demand, during the time of day when solar energy ramps down but while electric demand remains high – the so-called net peak demand period. This period generally covers the hours of 4:00 p.m. to 9:00 p.m., as described in Decision (D.) 21-03-056.

The Commission opened this rulemaking on November 19, 2020. During the proceeding's first phase, the Commission issued two decisions, D.21-02-028[2] and D.21-03-056,[3] focused on ensuring the State has adequate electric supply for 2021. The Commission ordered procurement of additional energy resources like storage, and created innovative Demand Response (DR) programs to help curb energy use during the critical hours of the day when the sun is setting but energy use remains high. The Commission is actively engaged in implementation of the Phase 1 decisions.[4]

This is Phase 2 of the proceeding, focused on increasing electric supply and reducing demand for 2022 and 2023. On July 30, 2021, Governor Newsom signed an Emergency Proclamation to "free up energy supply to meet demand during extreme heat events and wildfires that are becoming more intense and to expedite deployment of clean energy resources this year and next year."[5]

Among the directives included in the Governor's July 30, 2021 Emergency Proclamation was the following:

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[2] *Reh. denied,* D.21-05-036.

[3] *Modified,* D.21-06-027.

[4] For more information on implementation of activities related to summer reliability, *see* Summer Reliability (ca.gov).

[5] *See* https://www.gov.ca.gov/2021/07/30/governor-newsom-signs-emergency-proclamation-to-expedite-clean-energy-projects-and-relieve-demand-on-the-electrical-grid-during-extreme-weather-events-this-summer-as-climate-crisis-threatens-western-s/. (Press Release) and https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf. (Proclamation of a State of Emergency).

> All energy agencies shall act immediately to achieve energy stability during this emergency, and the California Public Utilities Commission is requested to do the same. In particular, the California Energy Commission is directed, and the California Public Utilities Commission and the California Independent System Operator are requested, to work with the State's load serving entities on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day.

The Emergency Proclamation also stated:

> The California Public Utilities Commission is requested to exercise its powers to expedite Commission actions, to the maximum extent necessary to meet the purposes and directives of this proclamation, including by expanding and expediting approval of demand response programs and storage and clean energy projects, to ensure that California has a safe and reliable electricity supply through October 31, 2021, to reduce strain on the energy infrastructure, and to ensure increased clean energy capacity by October 31, 2022.

On September 8, 2021, the CEC adopted a "Summer 2022 Stack Analysis" for summer 2022 to estimate the potential gap between supply and demand in 2022 under average and extreme weather conditions similar to those in summer 2020, and projected a potential need for contingency resources during summer 2022. This Commission has conducted an analysis with updated information of the potential shortfall at net peak in summers 2022 and 2023 under the most extreme conditions, and finds an additional need for supply- and demand-side resources of between 2,000 and 3,000 megawatts (MW).

On August 2, 2021, the assigned Administrative Law Judge (ALJ) sent a ruling to the parties setting forth a proposed scope and schedule for Phase 2.

After taking comment from the parties due on August 6, 2021, the Assigned Commissioner issued a scoping memo providing the scope and schedule of Phase 2, finding that "An expedited process is essential to ensure there is adequate supply and demand management to achieve electrical system reliability in 2022 and 2023."

The scope of Phase 2 was set forth as follows:

- Increase peak and net peak supply resources in 2022 and 2023:
  - Expedited generation and energy storage procurement, including utility-owned generation and third-party generation, and expedited contracting and other processes;
  - Updates to Resource Adequacy (RA) requirements;
  - CAISO's Capacity Procurement Mechanism authority;
  - Analysis of need/net-short – particularly at net peak – and resources available to meet this need, in light of recent trends in weather and resource availability;
  - Integrated Resource Planning (IRP) procurement - mechanisms to accelerate online dates;
  - Planning Reserve Margin (PRM) adjustment for 2022 and/or 2023;
  - Interconnection; and
  - Other opportunities to increase supply.
- Reduce peak and net peak demand in 2022 and 2023:
  - Flex Alert;
  - Critical Peak Pricing;
  - ELRP;
  - Modifications to existing supply-side DR programs (including Investor-Owned Utility (IOU) supply-side DR programs, DR Auction Mechanism (DRAM), and other third-party DR);

- o New DR programs or pilots including but not limited to the California Environmental Justice Alliance (CEJA) Just Flex Rewards, Pacific Gas and Electric Company (PG&E) Power Saver Rewards Pilot briefed during Phase 1, and capacity bidding program with dispatch in real-time market;
- o Electric vehicle participation in DR or load management;
- o Measures to minimize loss of DR enrollment;
- o Rate structures, including pilot rates introduced for a limited period or limited to certain customer classes or subsets of such classes; and
- o Other opportunities to reduce demand or net demand including virtual power plants, distributed energy resource export, distributed generation.

- Memorandum or Balancing Accounts to cover the cost of programs in 2022 and 2023.

The Phase 2 scoping memo also made clear that other Commission proceedings were already focused on increasing supply and/or reducing demand for reliability purposes, and instructed parties to participate in those cited proceedings if they wished to influence outcomes. The proceedings cited were the Energy Efficiency Rulemaking (R.) 13-11-005, Microgrids, R.19-09-009, and the Self-Generation Incentive Program, R.11-12-005;[6] the scoping memo directed parties wishing to influence outcomes in the listed proceedings to participate in those proceedings. We also served the scoping memo on the Commission's IRP and RA service lists.

After the scoping memo was issued on August 10, 2021, the Assigned ALJ furnished the parties a template to use to formulate their proposals for 2022-23 in

[6] The reference should have been to the latest Self-Generation Incentive Program proceeding, R.20-05-012.

a ruling dated August 11, 2021. In addition to inviting new proposals, the ruling allowed parties who had made proposals in Phase 1 that the Commission did not adopt to re-propose those options. The ruling also acknowledged that two parties, CEJA and PG&E, had made proposals after adoption of the Phase 1 decisions in July 2021, as authorized by an assigned ALJ ruling on June 14, 2021, and invited those parties to indicate whether they still supported their proposals. Parties were directed to include their proposals in opening testimony due September 1, 2021.

Energy Division staff also issued its own summer 2022-23 reliability concepts for party consideration, furnished to the parties by ALJ ruling dated August 16, 2021 (Staff Concept Paper). The Staff Concept Paper discussed a large number of supply- and demand-side options, aimed at sparking dialogue and shaping party proposals.

Parties served opening testimony on September 1, 2021, and reply testimony on September 10, 2021. Forty-seven parties served opening testimony and 26 served reply testimony.[7] This decision admits all testimony into the record.[8]

The parties filed opening briefs on September 20, 2021, and reply briefs on September 27, 2021. The ALJ also issued a ruling on September 30, 2021 proposing to take official notice of the CEC's Summer Stack Analysis described

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[7] A list of the parties that served opening and/or reply testimony, with the acronyms used in this decision to refer to them, appears in Attachment 3 to this decision.

[8] Citations to a party's Phase 2 opening and reply testimony appear in this decision as "[Name of party] Opening (or Reply) Testimony at [page number]," and opening and reply briefs appear as "[Name of party] Opening (or Reply) Brief at [page number]." Citations to comments on the Proposed Decision (PD) appear as "[Name of party] Opening (or Reply) PD Comments at [page number]."

above, and inviting comment. A handful of parties submitted comment on the stack analysis on October 7, 2021.

2. Issues Before the Commission

This decision adopts the following requirements designed to decrease energy demand and increase energy supply during peak demand and net demand peak hours in the event that an extreme heat event similar to the August 2020 event occurs in the summer of 2022 or 2023. In the order listed below, we address the following issues:

1. *Need*: The need for additional contingency resources to serve California's electricity customers in the event of extreme heat in summers 2022 and 2023;
2. *Demand:* New and modified demand-side programs, including DR program changes, ELRP changes and a new Residential ELRP pilot, a smart thermostat program and two dynamic rate pilots, along with extension of the Flex Alert paid media campaign to 2022 and 2023; and
3. *Supply*: New supply-side resources and policies to meet the need for electricity at net peak in summer 2022 and 2023.

Attachments 1 and 2 to this decision contain details of the programs we order in this decision, including program parameters, eligibility, process and implementation, rates, marketing and outreach, and cost allocation and recovery. Attachment 2 describes ELRP changes and Attachment 1 contains all other program requirements.

3. Need for Additional Resources

This section addresses the need for additional resources in the summers of 2022 and 2023 to help maintain reliability in the most extreme weather events, and includes a discussion of the PRM.

In summary, we find that if an extreme weather event were to occur, there is a need for contingency resources in the summers of 2022-2023 in the range of 2,000 MW to 3,000 MW. We are not changing the PRM applicable to IRP or RA obligations, which is being addressed in those proceedings, but instead we continue the approach adopted in D.21-03-056 of authorizing the three large IOUs to procure additional resources to meet an "effective PRM."

The 2,000-3,000 MW range provides for the procurement of contingency resources to meet an effective PRM of between 20% and 22.5% to ensure reliable electric supply during extreme circumstances. Additional resources that meet this higher effective PRM will provide additional reliability in the event of a need for contingencies above the existing PRM during extreme events.

3.1. Background on Procurement Need for 2022-2023

As discussed in D.21-02-028, the summer 2020 rolling outages spotlighted reliability deficiencies in California's electricity system. The Joint Agency Root Cause Analysis and party comments in this proceeding have pointed to a number of causes for the outages, as well as an array of solutions.

Since those events, the Commission has ordered additional procurement in multiple venues. We ordered additional procurement for 2021 and 2022 in Phase 1 of this proceeding, and additional procurement for 2023-2026 in the IRP decision on Mid-Term Reliability, D.21-06-035. Nonetheless, current planning and procurement resource levels may not be sufficient through 2023 under extreme conditions.

3.2. Party Comments on Procurement Need

Many parties supported continuing with the current approach to procure additional capacity needed in 2022 and in some cases 2023, or more broadly supported additional procurement.[9] Other parties opposed additional procurement for 2022 and/or 2023 without further analysis of need.[10] In addition, a number of parties supported a higher PRM,[11] while others opposed it absent a more complete loss of load study and consideration in the RA and IRP proceedings.[12]

With regard to the CEC 2022 Summer Stack Analysis, a small number of parties commented, and all of them pointed out limitations of the analysis.[13] SCE recommended changes to certain assumptions including the hydroelectric drought de-rate, import and retirement assumptions and base demand.[14] We apply SCE's general approach to examining the CEC 2022 Summer Reliability Stack Analysis below.

3.3. Determination of Procurement Need

Considering party comments, the CEC 2022 Summer Reliability Stack Analysis, recent CPUC decisions in the IRP and RA proceedings, the occurrence of reliability problems in 2020 during extreme weather events, CAISO's calling of Flex Alerts multiple times in the summer of 2021, and the Governor's July 2021

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[9] *See, e.g.,* CAISO Opening Testimony at 1-11; PG&E Opening Testimony at 9-6 - 9-8; Cal Advocates Opening Testimony at 1-3; SCE Reply Testimony at 18-19; SDG&E Opening Testimony, DeTuri and Maiga at 3-11, SDG&E Reply Testimony, DeTuri and Maiga at 2-3; MRP Reply Testimony at 3-4; LS Power Opening Testimony at 5-6.

[10] *See* TURN Reply Testimony at 3-4; UCS Opening Testimony at 2-7; PCF Opening Testimony at 9-14.

[11] CAISO Opening Testimony at 9-13; Cal Advocates Opening Testimony at 1-1 – 1-6; MRP Reply Testimony at 3-4; Calpine Reply Testimony at 6-7; LS Power Opening Testimony at 2; Wartsila Reply Testimony at 3-4; Saavi Energia Opening Testimony at 4.

[12] *See, e.g.,* UCS Opening Testimony at 3-6; PCF Opening Testimony at 6.

[13] *See, e.g.,* UCS Opening Testimony at 3; CalCCA Opening Testimony at Appendix A; SDG&E Opening Testimony, DeTuri and Maiga at 8-9; SCE Opening Testimony at 81.

[14] SCE Opening Testimony at A-1-4.

Emergency Proclamation, we determine that we must act now to ensure contingency reliability resources are available for the summers of 2022 and 2023.

Numerous extreme conditions and supply risks may be mitigated by continuation and expansion of contingency procurement in 2022 and 2023. The conditions include heightened risks associated with climate change, extreme heatwaves, dry hydro conditions, potential West-wide capacity shortages, supply chain issues with procurement underway, and project contract failures, among a host of other planning uncertainties.

Accordingly, this decision continues its order for the large electric IOUs to pursue incremental demand- and supply-side resources for 2022 and extends the order to 2023. In continuing with this approach, the Commission is exercising its policy prerogative to pursue a variety of strategies to increase supply and reduce demand to maintain reliability of the grid during extreme weather events.

As noted in D.21-02-028, this incremental procurement is intended to serve CAISO load, and we again encourage CAISO to ensure that these resources do not support exports even if they are not designated as RA resources.[15]

The subsequent sections address the approach we adopt for determining the exact amount of contingency procurement and the approach for realizing the procurement.

3.3.1. Adopted Procurement Need Direction

After consideration of the record of this proceeding, we determine that the appropriate approach for realizing the procurement to meet the need identified in this decision is to continue with the effective PRM approach adopted in Phase 1. The procurement from Phase 1 was targeted to an effective PRM of at

[15] D.21-02-028 at 9.

least 17.5% for 2021 and 2022, with a requirement that all resources procured to meet the effective PRM be available during net peak.

In this decision we extend the effective PRM approach to 2023 and increase the effective PRM target from 17.5% to a range of 20% to 22.5%.

3.3.2. Background on Emergency Reliability Procurement Target

In D.21-03-056, the Commission adopted an effective PRM of 17.5% for the IOUs, stating:

> Given that a portion of the resources that make up [Load Serving Entities' (LSEs')] 15% PRM are solar resources whose generation is declining rapidly at net peak, these procurement targets represent a floor, and the IOUs are encouraged to exceed their respective targets by as much as an additional 50%, which would result in approximately 1,500 MW of incremental procurement and *an* effective PRM of 19%. The additional 1,500 MW of resources is selected as an upper end target because it represents the [Net Qualifying Capacity (NQC)] of solar in September, which has been the Integrated Energy Policy Report forecast peak load month in recent years.[16]

3.3.3. Adopted Emergency Reliability Procurement Target

With regard to the amount of additional reliability resources that should be procured, we continue our current approach with some modification. We agree with CAISO, SCE, PG&E, SDG&E, Cal Advocates and other parties that recommend continuing the current approach to procurement of additional resources. The weather experienced throughout the summer of 2020 and 2021 was extreme, and we must plan in anticipation of more frequent extreme weather events resulting from climate change.

[16] D.21-03-056 at 43.

There must be sufficient resources in place to meet demand during the net peak hour. For this reason, we require all incremental resources procured as a result of this proceeding to be available during net peak. That is, because a resource such as solar is unavailable at net peak because the sun has set, it does not contribute to the need at net peak. Ultimately, changes to the Commission's overall resource planning framework may be necessary, but considerations of more permanent changes to the Commission's RA program requirements and longer-term planning standards should be made in the RA and IRP proceedings, respectively.

In recognition of the continued tight grid conditions experienced this summer, CAISO's testimony reflecting a significant shortfall in LSE supply plan resources at net peak,[17] and the need for additional contingency resources identified in the CEC Summer 2022 Stack Analysis, we establish a revised targeted procurement range of 2,000 MW to 3,000 MW for summers 2022 and 2023. This range is inclusive of, not additive to, the targeted procurement of 1,000 MW of contingency resources adopted in D.21-02-028 and D.21-03-056. As we explain below, the result is an effective PRM of 20% to 22.5% during system peak, and 15% to 17.5% at net peak.

While the Commission has reached this conclusion based on the factors detailed above, we include expanded discussion of the CAISO's net peak need analysis and the CEC 2022 Summer Stack Analysis in subsequent sections, as both analyses of potential need for contingency resources are complex in nature.

We choose to set a target range rather than a point target because we recognize there is current and near-term uncertainty both in demand variation

[17] CAISO Opening Testimony at 1-11.

and resource availability. The load impacts of the new and voluntary programs we adopt, and continue, in this decision cannot be predicted with certainty.

We expect a large quantity of new resources to come online in 2022, and subsequent years, as a result of the current IRP procurement authorizations. Given the magnitude of the procurement ordered, the timelines in which these resources are required to be online, and a number of procurement challenges discussed in this decision, there is risk that the over 40 LSEs responsible for this procurement will not bring all of the ordered resources online by the deadlines ordered in the IRP proceeding. Indeed, a recently released Energy Division report on the status of the August 2021 tranche of resources ordered in the D.19-11-016 procurement order indicates that a number of projects expected by August 2021 were delayed. [18]

In addition, much of this IRP procurement will be performed by LSEs that are relatively new, have never procured new resources in the quantities they have been ordered to procure, or both. We are concerned that adding the procurement of contingency resources to these existing challenges would only serve to further increase these challenges.

We therefore allocate procurement responsibility for the additional contingency resources ordered in this decision to the three large IOUs, using the same allocation ratios used for the summer 2021 incremental procurement. These ratios are based approximately on the Transmission Access Charge (TAC)

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[18] Energy Division Staff Report, "Procurement in Compliance with D.19-11-016 per February 1, 2021 Filings, 8/23/2021", available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/ed_staff_review_of_feb2021_data_in_compliance_with_d1911016.pdf, on the IRP Procurement Track (ca.gov) Website.

area CAISO load shares for each utility's service territory.[19] The resulting target procurement amounts are 900 MW-1,350 MW each for PG&E and Southern California Edison Company (SCE) service territories and 200 MW-300 MW for San Diego Gas & Electric Company (SDG&E) service territory. The additional resources to meet the 2,000 MW to 3,000 MW range must be available at peak and net peak. Further, we prioritize here the procurement of resources that are RA eligible and that will be visible to the CAISO in supply plans and participate in CAISO markets to the extent feasible.

The CEC's peak demand forecast for the CAISO TAC area for the 2022 summer months is approximately 45,000 MW, so each 1,000 MW is equivalent to approximately a 2.5% increase in the PRM for CPUC jurisdictional entities.[20] Thus, added to the 15% PRM requirement in the RA program that applies to all LSEs, the adopted range of additional contingency procurement results in an effective PRM of 20% to 22.5%. Importantly, these effective PRMs only apply to the CPUC jurisdictional LSEs' portion of CAISO load. To the extent that non-jurisdictional entities do not also procure to similar targets, the overall CAISO effective PRM would be lower than these estimates.

While the IRP decisions have ordered an additional 2,825 MW of new resources to come online for the summer of 2023 (825 MW by August 1, 2023 in D.19-11-016 and 2,000 MW more by August 1, 2023 in D.21-06-035), the uncertainties we describe above will persist into 2023. Specifically, concerns

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[19] *See* CEDU 2020 Managed Forecast – LSE and BA Tables Mid Demand – Mid AAEE Case – Corrected March 2021, Form 1.5b, https://efiling.energy.ca.gov/GetDocument.aspx?tn=237319&DocumentContentId=70504.

[20] As observed in D.21-02-028, 2.5% x 45,000 is approximately 1,100 MW, but since CPUC jurisdictional entities represent 90% of the CAISO TAC area, their share of the PRM is 90% of this value, or approximately 1,000 MW.

regarding resource availability at net peak will persist. LSEs may struggle to meet their existing 2022 and 2023 procurement targets given supply chain disruptions and other factors; risks of extreme weather will continue through 2023, including the risk that persistent drought conditions will diminish hydroelectricity supply. Even if these risks do not materialize, a portion of the supply is called upon and paid for only when there is a triggering event, reducing the cost associated with the procurement of contingency resources. Finally, a conservative approach can help avoid further just-in-time procurement in the future.[21] Consequently, we apply the adopted target procurement range of 2,000 MW-3,000 MW for 2023 as well.

Procurement of contingency resources for summer 2021 approached but did not fully reach the 1,000 MW target adopted in D.21-03-056 in all summer months. For instance, the IOUs collectively reached approximately 800 MW for August, whereas they surpassed the target in September with approximately 1,150 MW.[22] Looking ahead to the summers of 2022 and 2023, there is the real potential for delays associated with procurement already underway in compliance with the recent IRP decisions (D.21-06-035 and D.19-11-016), and practical timing constraints on the ability to bring new resources online between now and 2022 and 2023. For example, there are interconnection queue limitations, supply chain issues being faced as a result of the COVID-19 pandemic, high global demand for battery storage, and challenges with skilled labor availability for engineering and construction of new energy resources, all of

[21] *See* TURN Opening PD Comments at 1 (commenting on need in 2023).

[22] 2021 Excess Resource Reports. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

which will impact LSEs' ability to bring resources online in the coming two summers.

Based on these realities, we expect it could be extremely difficult to actually identify and procure sufficient demand- and supply-side resources to reach 2,000 MW of online and available contingency resources for summer 2022, let alone the 3,000 MW target. While we acknowledge the very real obstacles to procuring this amount of resources on such short timelines, it is important to identify the level of contingency resources that may be needed to ensure reliability in the most extreme weather events. The range of 2,000–3,000 MW is that level.

Given this difficulty, we understand the possibility that the IOUs may not achieve the targeted procurement by summer 2022 or 2023. It may not be possible to reduce the risk to zero during an extreme weather event given the short timeline we face. Nonetheless, we have created a pathway for significant additional demand- and supply-side contingency resources that we can count on going into the summer and that can be deployed in an organized and responsible fashion if needed.

Progress toward meeting the targeted procurement should be reasonably understood by mid to late spring 2022. At that time, in the event that sufficient progress has not been made, the State can determine whether there is a need for additional action to further reduce the risk of outages resulting from an extreme weather event as contemplated in the CEC 2022 Summer Stack Analysis.

While this expedited contingency procurement will certainly be challenging, there are several reasons to be guardedly optimistic that the IOUs can make significant progress toward meeting the targeted procurement by next summer. For instance, the resources procured for summer 2021 reliability in response to the previous decisions in this proceeding that are still in place for 2022 and 2023 can help meet these targets. In addition, we are authorizing this procurement with a longer lead time than the 2021 contingency procurement, so there is a greater amount of lead time for 2022 and 2023 procurement to meet emergency summer reliability needs. We have also identified a broader array of resources that can be procured to achieve these targets, which could increase the amount of resources that can successfully be brought online by 2022 and 2023 compared to 2021. Programs authorized by and continued via this decision, such as the ELRP program and dynamic rates pilots, count toward the contingency procurement targets.

In the event that emergency procurement efforts are so successful that they result in excess procurement, the resources could be used as backfill in the event some LSEs fail to meet their IRP procurement requirements. They could also allow for downward adjustments in future procurement orders, or help support faster retirement of aging generation not accounted for in previous IRP orders.

The following sections include expanded discussion of the CAISO's net peak need analysis and the CEC 2022 Summer Stack Analysis, as both these analyses of potential need for contingency resources are complex in nature.

3.3.4. CAISO Net Peak Analysis

CAISO recommends the Commission establish a net peak RA requirement and increase the PRM from 15% to 17.5%.[23] The Utility Reform Network (TURN) supports CAISO's recommendation of a net peak RA requirement and the methodology CAISO proposes.[24] CAISO's net peak RA proposal would set an RA requirement at 8:00 p.m. and assume zero solar production at this hour,

[23] CAISO Opening Testimony at 2-11 and 12-14.

[24] TURN Reply Testimony at 4-6.

leaving the eligible RA capacity value of solar at zero, and making solar ineligible to meet any part of the net peak RA requirement.

This approach does not take into account that other resources also produce differently at net peak. For instance, the nameplate capacities of natural gas plants are de-rated to reflect their output during gross peak when temperatures are typically at their highest levels and output is most impacted, and wind speeds typically begin picking up in the evening hours compared to the gross peak. Under a net peak RA requirement, if established, some technologies might have higher eligible RA capacity value while solar might be zero. De-rating a solar resource's ability to serve a new net peak PRM standard without reviewing how other resources serve load at net peak may be an over-simplification of a complex planning problem.

If one nonetheless considers the CAISO analysis, certain results emerge. In its testimony, CAISO provides a table that estimates the 2021 resource shortfalls that would result from a net peak RA program with the current 15% PRM, which ranges from a 972 MW shortfall in May to a maximum shortfall of 1,951 MW in August 2021.[25]

The CAISO's analysis uses a net peak forecast for 2021 that is approximately 1,100 MW lower than the August 2022 net peak forecast used in the CEC's Stack Analysis. Further, several hundred megawatts of resources shown on the August 2021 supply plans were procured as a result of this proceeding. Since these resources were above the LSEs' collective 15% PRM obligation, they would be redundant with the additional procurement target we set in this decision.

[25] CAISO Opening Testimony at 8.

In addition, because the CAISO's analysis uses resources included on August 2021 supply plans, its analysis excludes 2021 IRP resources ordered in D.19-11-016 that were not online by August 2021 and the 850 MW of 2022 IRP resources ordered online by August 2022 in D.19-11-016. The increase in the net peak forecast (1,100 MW) largely nets out with the additional 2021 and 2022 IRP resources, so applying CAISO's net peak approach to August 2022 results in a shortfall of approximately 2,200 MW. Adjusting for the 90% of CAISO load represented by CPUC jurisdictional LSEs, achieving a 15% PRM at net peak would require procurement of an additional 2,000 MW by CPUC jurisdictional entities in 2022.

CAISO provided an illustrative analysis of net peak at 15% and also recommended adopting a 17.5% PRM.[26] As noted previously in this and past decisions, a 2.5% adjustment to the PRM represents approximately 1,000 MW for CPUC jurisdictional entities' share of CAISO load, so achieving a 17.5% PRM at net peak would require 1,000 MW of resources in addition to the 2,000 MW of procurement needed to meet the 15% PRM at net peak.

After adjusting for August 2022 demand forecast and supply differences compared with August 2021, CAISO's proposed net peak RA requirement results in a need for 2,000 MW of additional resources available at net peak to achieve a 15% PRM and 3,000 MW to achieve a 17.5% PRM.

We understand that it may be the CAISO's preference that all of the resources procured to meet its targeted net peak PRM would be RA eligible resources which are visible to them on supply plans, and in an ideal world we would prefer this to be the case as well. However, given the timelines for

[26] *See* CAISO Opening PD Comments at 2.

procurement and the size of the need for contingency resources, we believe it could be extremely challenging for these levels of new RA-eligible resources to be brought online by next summer, in addition to the significant amount of procurement already underway. Consequently, this decision authorizes the procurement of a wide variety of resources, some of which will be RA resources that will be visible to the CAISO on supply plans, while others will not. We prioritize here the procurement of resources that are RA eligible and that will be visible to the CAISO in supply plans and participate in CAISO markets to the extent feasible.

3.3.5. CEC 2022 Summer Stack Analysis[27]

Following the grid stresses experienced in June and July 2021, the CEC developed an hourly stack analysis for summer 2022 to provide near-term situational awareness in the event of West-wide extreme weather and prolonged drought (CEC 2022 Summer Stack Analysis).[28] The CEC analysis provides a snapshot of an extreme weather event coupled with conservative assumptions on availability of hydroelectric and imported resources and the potential need for contingencies in summer 2022. The CEC analysis can be used as a point of reference in determining resources needed to maintain grid reliability in the most extreme summer weather events. However, as noted in the Appendix to the

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[27] On September 30th, the ALJs issued a ruling taking official notice of the CEC 2022 Summer Stack Analysis and requesting party comments. The comments in response generally supported the approach taken here, in which the Commission broadens the analysis and applies its own policy expertise to assess the need for additional resources.

[28] 411194667.PDF (ca.gov) or CEC, "2022 Summer Stack Analysis," September 2021, CEC-200-2021-006, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M411/K194/411194667.PDF.

CEC's adopted Summer 2021 Mid-term Reliability Analysis,[29] the Summer Stack Analysis is:

> . . . primarily intended to provide a snapshot of a potential worst-case scenario to inform the level of contingencies that the state should plan for. As such, the extreme scenario is developed to capture extreme demand and supply conditions that might represent a very low likelihood. While portions of an identified shortfall using the Hourly Stack Analysis in an extreme weather scenario might be deemed necessary to be addressed by additional procurement, *the intention of an Hourly Stack Analysis is not to determine whether traditional procurement is needed.* (Emphasis added.)

The CEC 2022 Summer Stack Analysis observes that resources equivalent to a 22.5% PRM may be needed to prevent rotating outages during a "worst case scenario" that assumes a high level of resource outages, persistent drought conditions, and limited or no access to additional economic imports all occur simultaneously. The CEC then considers the resulting need for contingency resources (or "net short" in shorthand) if these extremes occur at the peak and net peak hours of each summer month. Under this scenario, the analysis projects potential need for contingency resources during a few hours that could range from 200 MW to 4,350 MW.

As stressed by the CEC in its Mid-term Reliability Analysis, this risk stacking approach is a different approach to need determination from traditional electricity resource planning and RA approaches and is not intended to determine the level of traditional resources needed. Resource planners forecast the probability of a loss of load event based on historic variations in weather, electricity demand, and resource performance. Traditionally, California resource

[29] CEC, "Midterm Reliability Analysis," September 2021, CED-200-2021-009, at A-1. https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf.

planning uses a "probabilistic" approach – that is, it considers various scenarios, rather than a single worst-case scenario. The CEC analysis takes a "deterministic" approach that assumes all worst-case scenarios occur simultaneously. Acknowledging these differences, we do find it helpful to compare the resulting net short with the procurement range adopted in this decision.

In examining an extreme scenario, the CEC uses conservative assumptions for available supply and expected demand. For example, the analysis assumes a 40% reduction in the DR resources that will be available in the future based on DR performance described in the Final Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave, which results in an assumed maximum of 1,000 MW in 2022.[30] The analysis also assumes that the Redondo Beach once-through-cooling generating station (834 MW) will retire in 2021 and thus not be available to serve load in 2022. In addition, the analysis uses an average of several recent years of RA imports as a proxy for the estimated MW value available from 2022 RA imports. Finally, to account for increasingly common extreme weather events and higher levels of unanticipated outages of RA resources than historically assumed, the CEC analysis builds in a PRM of 22.5% through both the peak and net peak periods.

The CEC noted the assumptions used in its analysis were based on the best data available to it at the time and recognized the need to update these assumptions as new information becomes available,[31] including considering

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[30] Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf (caiso.com).

[31] 411194667.PDF (ca.gov) or CEC, "2022 Summer Stack Analysis," September 2021, CEC-200-2021-006, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M411/K194/411194667.PDF.

adjustments to its peak load forecast meant to further reflect climate change.[32] This decision discusses new information with regard to some of the assumptions used in the analysis. With regard to expected DR resources, energy use on future extreme weather days may be far higher than CAISO assumed in estimating the DR load drop of these customers during the 2020 events.[33] We addressed this issue in D.21-03-056 in Phase 1 of this proceeding, noting that

> the CAISO indicates it is contemplating potential baseline adjustment increase(s) during stressed grid conditions. The IOUs are directed, and third-party DR providers are invited, to work collaboratively with the CAISO to explore baseline options during stressed system conditions. As a result of this exploration, to the extent the CAISO introduces new baseline options for energy market settlement, the IOUs are permitted to utilize the new baseline options in their respective [Capacity Bidding Programs (CBPs)], and DR providers are permitted to utilize the new baseline options for the [DRAM]. D.21-03-056 at 31-32.

The Commission's Load Impact Protocol process[34] estimates the load impact of DR programs for the upcoming year. There is necessarily a lag in this analysis because DR providers (DRPs) estimate performance for the year ahead. Thus, for example, filings in 2021 include projected estimates of resources that will be available in 2022, based on analysis of DR resources' performance in 2020.

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[32] "Adjusting for Climate Trends in Normal Peak Loads," Demand Analysis Working Group, September 2021, https://www.energy.ca.gov/sites/default/files/2021-09/7%20Climate%20Trends%20and%20Normal%20Peak%20Loads_ADA.pdf.

[33] The public versions of the Load Impact Protocol filings associated with the DR that was under contract with CPUC-jurisdictional entities during the summer 2020 heat waves are available on the Commission's website for R.13-09-011.

[34] For a general overview of the process, *see* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/introduction-to-load-impact-protocols-lips.pdf.

The Load Impact Protocol analysis suggests that when baselines are adjusted for the extreme weather events, DR in aggregate performed much closer to estimated levels during the August and September 2020 heat waves. It makes downward adjustments to 2022 DR values to reflect the performance of some categories of DR resources. Consequently, the Load Impact Protocol-adjusted values for 2022 DR resources represent a reasonable estimate of expected performance of DR resources procured by CPUC-jurisdictional entities, excluding credits for avoided PRM procurement and avoided line losses.

Current summer 2022 DR authorizations for CPUC jurisdictional LSEs, IOU DR, DRAM contract estimates and third-party DRPs based on the Load Impact Protocol analysis of 2020 DR performance are approximately 1,650 MW.[35] If one adds to this number the CEC's estimate of 2022 DR procurement by LSEs that are not under CPUC jurisdiction, the total DR value for 2022 is approximately 1,700 MW. This is 700 MW more than the 1,000 MW value included in CEC's analysis; making this adjustment to reflect Load Impact Protocol-based expected DR values for 2022 would reduce the CEC's net short estimate by approximately 700 MW.

With regard to the assumption of Redondo Beach generating station availability in 2022, on October 19th, the California Water Resources Control Board voted to extend the Redondo Beach generating station permit through 2023,[36] which is information the CEC did not have when developing its analysis. This additional resource reduces the net short estimate by an additional 834 MW.

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[35] 2022 DR Values are posted to this Commission's RA compliance website - Resource Adequacy Compliance Materials (ca.gov).

[36] For information regarding the California Water Resources Control Board's decision, *see* https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.html.

The CEC assumes imports based on average of several years of RA imports as a proxy for 2022 RA imports. However, this approach does not fully reflect changes in the Commission's RA import policy that took effect this year. The 2021 levels of RA imports therefore represent a more accurate proxy for 2022 RA imports than an average of several years. The 2021 RA imports for July, August, and September 2021 were 5,800 MW, 6,000 MW, and 6,700 MW, respectively. Using these values rather than the multi-year averages results in a reduction in the net short estimate by approximately 500 MW for July and September and an increase in the net short by approximately 500 MW for August.

Finally, the CEC 2022 Summer Stack Analysis indicates that it includes the expedited procurement resources that were previously directed in this proceeding in its estimate of new resources coming online by next summer, and these megawatts would be redundant with the resources we authorize in this proceeding. Thus, 1,000 MW of resources need to be added to the CEC's net short estimates to avoid double-counting.

Applying all of the foregoing adjustments to the CEC 2022 Summer Stack Analysis of net short during the most extreme weather events results in a September 2022 need for additional contingency resources at net peak of approximately 3,320 MW (4,350 MW minus 700 MW of additional DR, 830 MW for the Redondo Beach Generating Station, and 500 MW additional September RA imports, plus 1,000 MW of expedited procurement resources included in the CEC's analysis). Adjusting this result, which is a CAISO-wide analysis, to reflect the 90% of CAISO load represented by CPUC jurisdictional entities, the resulting net short estimate is approximately 3,000 MW (90% of 3,320 MW).

We turn to a determination of how to meet our estimate of a needed 2,000 to 3,000 MW in an extreme weather event. We first discuss demand-side programs, and then discuss supply-side programs and processes.

4. Demand Side Changes

4.1. Modifications to ELRP

4.1.1. Background of the ELRP

The Commission adopted the initial program parameters for ELRP in the second decision in this proceeding, D.21-03-056. That decision explained the purpose of ELRP is to allow the large electric IOUs and the CAISO to have access to additional load reduction opportunity during times of high grid stress and inadequate market resources. The goal of developing ELRP was to provide additional tools for the avoidance of rotating outages while also minimizing costs to ratepayers.

The initial program parameters for ELRP included a duration of five years and participation of both customers not participating in market-integrated (also referred to as supply-side) DR programs and participating in CAISO market-integrated Proxy Demand Resources (PDRs). The Commission then adopted D.21-06-027 that modified the parameters of ELRP that were initially set in D.21-03-056 regarding the availability of a day-of trigger for Group A participants.

To achieve greater value from ELRP, this decision makes further refinements to the parameters of the ELRP, as adopted in Attachment 2 of this decision. Attachment 2 contains the guidance that the Commission has previously adopted regarding the parameters of the ELRP. At a high level, the modifications outlined in Attachment 2 to ELRP expand the existing group of eligible customers and add further eligibility for non-residential aggregators, Vehicle-Grid Integration (VGI) aggregators, and residential customers.

4.1.2. Modifications to the ELRP Framework

Several non-substantive modifications have been made to the ELRP guidance to improve readability and clarity of interpretation.

Additionally, in accordance with the Commission's grant of the large IOUs' motion for extension of time to file their DR applications, the review of the ELRP has been moved to continue to coincide with those applications in 2022.

4.1.3. Group A.1 Non-Residential Participant Eligibility

The eligibility requirement that Group A.1 participants in ELRP not take current service on a critical peak pricing or real-time pricing equivalent tariff is removed. We adopt this position with consideration of testimony from SCE and CALSSA.[37]

Additionally, the minimum size threshold parameter for Group A.1 participants in ELRP is modified in SCE's territory from 200 kilowatts (kW) of peak demand to 100 kW of peak demand and for SDG&E's territory the requirement for customers to drop 100 kW is modified to 50 kW. SCE and SDG&E both indicate they believe they have the capability to allow smaller enrollment sizes. This should allow for more medium-sized businesses to participate in ELRP, which otherwise may not have been possible with the previously, higher minimum size thresholds.[38]

4.1.4. Group A.2 Non-Residential Aggregators Eligibility

The A.2 group is expanded to included non-Base Interruptible Program (non-BIP) aggregators of non-residential, non-BIP customers. Non-BIP

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[37] CALSSA Reply Testimony at 8; Joint DR Parties Reply Testimony at 11; SCE Opening Testimony at 36-37.

[38] CESA Reply Testimony at 19; Joint DR Parties Opening Testimony at 26; SCE Opening Testimony at 37; SDG&E Opening Testimony, Mantz and McConnell at 17.

aggregators with aggregated customer resources meeting the following criteria are eligible to participate in ELRP:[39]

- The aggregated resource is not simultaneously enrolled in a supply-side DR program offered by an IOU, third-party DRP, or Community Choice Aggregator (CCA),
- Customers participating in the aggregation meet the eligibility criteria under A.1 (except the Minimum Size Threshold requirement does not apply), and
- The aggregated resource capacity meets or exceeds the Minimum Aggregation Size Threshold.

If a non-BIP aggregator of non-residential customers chooses not to participate, its customers may independently participate in ELRP under A.1, subject to the applicable criteria and requirements.

The IOUs are authorized to dispatch the aggregated resources offered by the non-BIP aggregators for at least the Minimum Aggregation Dispatch Hours. In addition to the Group A triggers defined below, the IOUs may exercise discretion to dispatch the non-BIP aggregation in response to other forecasted or anticipated grid stress conditions, such as high locational marginal prices in the CAISO markets, extreme heat waves, etc., to achieve the Minimum Dispatch Hours. The IOUs may negotiate agreements with the non-BIP aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation.

The Minimum Aggregation Size Threshold is set at 500 kW. The Minimum Aggregation Dispatch Hours is set at 10 hours per season.

[39] AEE Opening Testimony at 4.

This modification is made to provide more certainty to aggregators regarding potential compensation for the participation of customers in Group A.2.

4.1.5. Group A.3 Rule 21 Exporting DER Eligibility

This decision clarifies that non-residential Net Energy Metering (NEM) customers meeting the eligibility standards outlined for Group A.3 participants are eligible to participate in ELRP. NEM customers have been eligible to participate as Group A.3 participants from the inception of the ELRP, and this modification clarifies the ways to participate.

We clarify that sub-group A.3 involves direct participation by a single customer with Rule 21 Exporting Distributed Energy Resources. Later in this decision, we discuss the addition of a new ELRP sub-group A.5 that involves participation by an aggregator with a VGI aggregation of one or more customers' sites.

4.1.6. Group A.4 Virtual Power Plant (VPP) Aggregator Eligibility

Regarding VPP aggregation eligibility, modifications are made to Group A.4 participation guidance.

We authorize stand-alone storage to participate.[40] This type of load shift can help grid reliability, and ELRP incentives for Incremental Load Reduction should compensate these stand-alone batteries for the service they provide to the grid.

We further provide guidance for minimum number of compensated dispatch hours. We make this modification with consideration of testimony from

[40] Joint DR Parties Opening Testimony at 24.

the Joint DR parties. Joint DR Parties indicate they "support establishing an ELRP reservation payment or minimum dispatch guarantee to customers with [Behind The Meter] storage resources and eligible back-up generation."[41] The minimum VPP dispatch hours is set at 20 hours per season.

The IOUs may negotiate agreements with the VPP aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation.

4.1.7. Group A.5 Electric Vehicle (EV) and Vehicle-Grid Integration (VGI) Aggregator Eligibility

We adopt a proposal with modifications from the Staff Concept Paper that expands ELRP eligibility to include additional uses of EVs and VGI for emergency reliability purposes. The new EV/VGI aggregator option will be labeled ELRP Group A.5.

The new ELRP group builds on ELRP Group A.3 as adopted in Phase 1. New ELRP Group A.5 is open to aggregations consisting of any combination of EVs and charging stations. Such aggregations may include groups of customers with EVs capable of managed one-way charging (V1G) and bi-directional charging and discharging (V2G). Both bundled and unbundled residential customers and/or non-residential bundled or unbundled customers that meet the criteria listed below are eligible to participate via the aggregations in ELRP Group A.5.

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[41] *Id.*

4.1.7.1. Background on ELRP EV/VGI

The Legislature[42] and the Commission[43] have affirmed that EVs can provide benefits to the grid by "altering the time, charging level, or location at which grid-connected [EVs] charge or discharge." The ELRP pilot adopted in D.21-03-056 included Group A.3, which allows EVs at a single host site to support the grid at net peak through V2G export.

The Staff Concept Paper in this proceeding asked for party input on an additional option to allow aggregation of EVs capable of managed charging and discharging (including V1G managed charging or V2G discharge) to support the grid at net peak and increase the effectiveness of the ELRP:

> **1(d). Electric Vehicle/Vehicle to Grid Integration (EV/VGI) Aggregation Pilot:**
>
> Currently the ELRP pilot has at least one provision (Group A option A.3) to allow electric vehicles to support the grid at net peak through vehicle to grid export. Energy Division Staff believes there may be additional potential for VGI aggregation integration (V1G managed charging and/or V2G discharge) to support the grid at net peak and to increase the effectiveness of the ELRP. Aggregating and dispatching EV resources through the ELRP represents an opportunity to enable and demonstrate the technical capabilities and customer engagement strategies necessary to harness and deploy this nascent resource. These efforts could serve to establish a foundation for further deployment of VGI resources, which is a priority for the CPUC and EV stakeholders given the enormous potential of these resources. The pilot may require revisions to interconnection rules to enable streamlined and affordable access to the grid for EVs and EV

[42] Senate Bill (SB) 676, Stats. 2019, Ch. 484 ("This bill would require the PUC, by December 31, 2020, in an existing proceeding, to establish strategies and quantifiable metrics to maximize the use of feasible and cost-effective electric vehicle grid integration by January 1, 2030.").

[43] D.20-12-029 at Section 4, "Revising the Definition of Electric Vehicle Grid Integration."

Supply Equipment (EVSE) with bi-directional capabilities. Staff proposes:

i. Allow aggregators to utilize networks of V1G or bi-directionally capable charging stations (EVSEs) to be eligible to participate in ELRP, providing the aggregation can contribute [Incremental [L]oad [R]eduction . . . exceeding the Minimum VGI Aggregation Size Threshold of 25 kW within an IOU service territory.

ii. The IOU shall dispatch the VGI aggregators for at least 30 hours per season including ELRP events and compensate the aggregators for the [Incremental Load Reduction] delivered during the dispatched hours.

iii. In case the EVSE is located on different meter (stand-alone EVSE) from the related host site meter (for example, Multi-Unit Dwellings), the aggregator is permitted to virtually aggregate the stand-alone EVSE meter(s) with the host site load on the different meter to partially bypass the V2G export restriction on the stand-alone EVSE meter(s). The virtual load aggregation of all stand-alone EVSEs and the related host site must not be negative at any time, even when the host site is participating in an event called by another DR program. V2G discharge is prohibited outside of the IOU dispatched hours.

iv. The [Incremental Load Reduction] settlement shall be based on the measurements at the EVSE meter, or EVSE sub-meter if the EVSE is taking service through the host site meter.[44]

4.1.7.2. Party Comments on ELRP EV/VGI Aggregation

As detailed below, there was broad support for the Staff Concept Paper proposal to increase EV/VGI options in ELRP from parties (AEE, CESA, Joint

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[44] Staff Concept Paper at 5.

DR, Joint Parties, VGIC, PG&E, SDG&E, ev.energy), with some limited dissent (CALSSA and SCE).[45]

PG&E generally supports the staff concept, while SCE asserts the proposal would not result in any meaningful contributions to 2022 system reliability based on SCE's current record. SCE states it has no two-way charging stations, and that it is aware of two existing two-way charging stations that have resulted in only one request for SCE's interconnection queue. CESA responds to SCE's assertion that there is limited potential for two-way charging by noting this commercial pathway has not yet been fully implemented.[46]

Other issues raised by parties include ev.energy's and VGIC's request to define "aggregators" broadly to include DR third-party providers and any managed charging company or vendor capable of controlling EV charging, including those that contract bilaterally with IOUs or CCAs. These parties also ask the Commission not to require aggregators to integrate directly with the CAISO.

CALSSA states the Commission should have the same rules for EVs/EVSE and stationary battery storage, since the technology is fundamentally the same. VGIC responds that EVs are similar but need special attention because they are not currently eligible for the subsidies allowed for storage in the Commission's NEM and Self Generation Incentive Programs.

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[45] *See generally* AEE Opening Testimony at 5; CALSSA Opening Testimony at 3; CESA Opening Testimony at 52, Reply Testimony at 22; Joint DR Parties Opening Testimony at 26; Joint Parties Opening Testimony at 13; VGIC Opening Testimony at 3; PG&E Opening Testimony at 7-3; SCE Opening Testimony at 68; SDG&E Opening Testimony, Mantz and McConnell at 22; ev.energy Opening Testimony at 7; and Enchanted Rock Reply Testimony at 6.

[46] CESA Opening Testimony at 23.

VGIC estimates an approximately 270 MW contribution to the grid by year 2 of the pilot based on VGIC's assumed 5% participation rates and VGIC's assumed potential for each EV to reduce load from V1G by 5 kW during an ELRP event. MCE comments that its own managed charging pilot had reductions of 1.4 kW of load per driver (V1G). VGIC estimates that V2G participation could provide an additional 23 MW. (MCE does not estimate load reduction potential for V2G.)

CESA, the Joint DR Parties and VGIC support the staff proposal that IOUs dispatch VGI aggregations for at least 30 hours per season. VGIC notes that establishing a minimum number of dispatch hours per season provides certainty to aggregators on the level of compensation. The Joint DR parties assert a capacity or reservation payment or minimum number of dispatch hours are important signals to encourage participation.

SDG&E and PG&E have concerns about a 30-hour guarantee. SDG&E opines that 30 hours is not reasonable, noting that had the ELRP pilot existed in 2019, SDG&E would likely have had zero ELRP events because no critical peak pricing events were called that year. PG&E states that mandating IOUs to force dispatch for at least 30 hours without an emergency does not seem to align with how and why ELRP was developed. CESA and VGIC respond that the IOUs could identify and define either lower trigger points (*e.g.,* CAISO Flex Alerts instead of the CAISO Alert, Warning, Emergency signal) or other applications for which these aggregated resources could be useful.[47]

[47] Comments on the 30-hour minimum appear in CESA Opening Testimony at 52, Reply Testimony at 23; Joint DR Parties Opening Testimony at 26; VGIC Opening Testimony at 10, Reply Testimony at 5l; PG&E Opening Testimony at 7-4; and SDG&E Opening Testimony, Mantz and McConnell at 22.

On the staff proposal of a 25 kW minimum threshold for aggregators, VGIC asks for a lower 15 kW threshold to maximize participation from EVs, while PG&E asserts the 25 kW threshold is a realistic target.[48]

4.1.7.3. Adopted Direction for ELRP Group A.5, EV/VGI Aggregation

We adopt with modifications the staff proposal for EV/VGI aggregations including both one-way managed charging and bi-directional EV charging and discharging. We acknowledge that the impact of including VGI aggregation under Group A.5 is uncertain, but we see the pilot as an opportunity to deploy and scale this resource, which will be critical in the coming years to ensure EVs can enhance reliability. Certain technical details for Group A.5 were changed in response to comment on the proposed decision and appear in Attachment 2 to this decision.

Technology capable of bi-directional EV charging is relatively new to the market and public uptake and awareness are low. Understanding this resource will be critical in the coming years to ensure EVs can enhance reliability and provide flexibility to the grid. A pilot program could help highlight the technology's potential, while contributing some support to the grid at net peak.

ELRP Group A.5 is open to VGI aggregators of any combination of EVs and charging stations operating in V1G or V2G configurations. Aggregators may deploy the service with residential or non-residential bundled or unbundled customers.

All participants must meet the following criteria:

- The VGI aggregation or any customer site within the aggregation is not simultaneously enrolled in a

[48] VGIC Opening Testimony at 16; PG&E Opening Testimony at 7-4.

market-integrated, supply-side DR program offered by an IOU, third-party DRP or CCA;

- All sites within the VGI aggregation are located within the distribution service area of a single IOU; and
- The VGI aggregation can contribute Incremental Load Reduction, as defined in Attachment 2, equal to or greater than the Minimum VGI Aggregation Size Threshold for a minimum of one hour.

NEM customers with EVs meeting the above requirements are eligible to participate in the VGI aggregation. Attachment 2 spells out additional technical details of the program, including the use of sub-metering, Rule 21 interconnection requirements, and IOU rights and responsibilities.

Staff proposed that the IOUs dispatch the VGI aggregators for at least 30 hours per season including ELRP events and compensate the aggregators for load reduction delivered during the dispatched hours. We adopt minimum VGI dispatch hours of 30 hours per season as an incentive for customers to participate in the program since they would otherwise have no assurance of receiving compensation.

While there may not be 30 "emergency" hours in a season, the IOUs may dispatch the VGI aggregation during other times of system need. In addition, the dispatch process will help educate customers, aggregators, IOUs, and the Commission on the technology and systems needed to dispatch these resources.

IOUs have discretion to meet the 30-hour minimum by dispatching aggregators in response to forecasted or anticipated grid stress conditions, such as high locational marginal prices in the CAISO markets and extreme heat waves. The IOUs may negotiate agreements with the VGI aggregators to clarify other requirements needed, including potential administration fees, to implement the dispatch hours and compensation.[49]

The staff concept proposal was for an aggregation size threshold set at a 25 kW minimum discharge level. We adopt the staff concept proposal for a minimum VGI aggregation size of 25 kW. This minimum level will encourage aggregators to increase the pool of participants and reduce administrative costs for IOUs.

To determine compensation for Incremental Load Reduction, an EVSE meter, or EVSE sub-meter if the EVSE is taking service through the host site meter, may be used. The EVSE sub-meter must meet applicable standards established by the Commission if and when adopted.[50]

We also provide flexible options to allow EVs to safely discharge for purposes of ELRP participation as noted further in Attachment 2.

4.1.8. ELRP Group B Market-Integrated Resources Eligibility

We clarify that at the time of enrollment, or at designated times during the ELRP pilot, Group B participating DRP will list the PDRs that will participate in ELRP and nominate an estimated target load reduction quantity (August) to be achieved during an ELRP event by each participating PDR resource. Participation during an ELRP event is entirely voluntary, and no financial

[49] In response to comments on the Proposed Decision, Attachment 2 contains additional detail regarding negotiating these agreements.

[50] PG&E, SCE and SDG&E filed a Final Plug-In Electric Vehicle Submetering Protocol in R.18-12-006 pursuant to an August 19, 2020 *Ruling Resetting Procedural Schedule to Continue the Development of a Plug-in Electric Vehicle Submetering Protocol*.

penalties will result from not meeting or exceeding the nominated target load reduction quantity during the event.[51]

4.1.9. Backup Generation Dispatch Prohibition in Disadvantaged Communities

Any load reduction technology may be used during an ELRP event to achieve Incremental Load Reduction. Prohibited resources, except those operated by non-residential customers located in Disadvantaged Communities, may be used when permitted by a Governor's Executive Order and in compliance with Rule 21 and other applicable regulations and permits, during an ELRP event to achieve Incremental Load Reduction, including during the overlapping period with an independently triggered event in a dual-enrolled DR program, but only for achieving load reduction incremental to any other existing commitment (*e.g.*, under a dual-enrolled DR program). The existing Prohibited Resources policy still applies to IOU and third-party managed DR programs, excluding ELRP.

This modification from the proposed decision is made in consideration of the totality of comments from many parties, including PG&E and CEJA. This covers both the elimination of the BUG dispatch sequence that was included in the proposed decision and the replacement of the elimination from participation of non-residential customers that utilize BUGs in Disadvantaged Communities.

As discussed in the Flex Alert paid media campaign section of this decision, messaging discouraging use of BUGs that use prohibited resources in the Residential ELRP is also ordered.

[51] SCE Opening Testimony at 38.

4.1.10. Group B Day of Trigger

We clarify that the ELRP day of trigger for Group B resources is activated when a Warning or Emergency, per the Alert, Warning, Emergency process, is declared by the CAISO. The start time and duration specified in the CAISO's declaration defines the Group B ELRP event window.

Adding a day of trigger for Group B will add additional load curtailment potential on days when the CAISO's Alert, Warning, Emergency declaration is made for the same day. It would also create more parity between the two ELRP groups.

4.1.11. ELRP Compensation Rate

The ELRP Compensation Rate for both Group A and B is set at $2 per kilowatt-hour (kWh) or $2,000 per megawatt-hour (MWh).[52] We remove the requirement that ELRP compensation for an event to be bounded for Group A participants between 50 and 200 percent of pre-nominated load shed or exported energy quantity.[53]

Parties noted that the California State Emergency Program (CSEP), the emergency demand reduction program initiated by Governor Newsom's July 30, 2021 Emergency Proclamation, set a compensation level of $2/kWh. The Joint Parties indicated that this compensation level should be extended to the ELRP for all participants.[54]

PG&E took a more cautious approach to considering the appropriate compensation level for ELRP, indicating that it is not clear that doubling the

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[52] CESA Opening Testimony at 51, Joint DR Parties Opening Testimony at 26, SCE Opening Testimony at 37-38.

[53] CESA Opening Testimony at 51, Joint DR Parties Opening Testimony at 26.

[54] Joint DR Parties Opening Testimony at 7.

compensation level is justified at this time. SCE was more supportive of aligning the ELRP compensation level with the CSEP. SDG&E did not object to increasing the ELRP compensation to $2/kWh, although it did caution that this could create the expectation for other DR programs to be aligned with this significantly higher compensation than existing programs.

Additionally, some parties advocated that the Commission adopt a significantly higher compensation rate in the ELRP, as high as $6/kWh in some circumstances.

Ultimately, in setting the compensation level for ELRP we recognize the emergency nature of the ELRP and accept that a higher compensation for this emergency program could avert unexpected outages during time of extreme weather. A compensation level of $2/kWh is appropriate because this program is triggered during times of the grid being the most stressed.

Regarding Group A.4 VPP compensation, the adopted baseline methodology may be used in conjunction with a meter or a sub-meter associated with a storage device that directly measures the energy flows into/out of the storage device to determine the Incremental Load Reduction for the ELRP settlement.[55]

4.1.12. Advice Letters

We clarify the requests for modification to the ELRP framework that can be requested by the IOUs through Tier 2 Advice Letter. We extend the subjects that may be addressed in Tier 2 Advice Letters to include issues of dual participation between ELRP and other DR programs and issues of minimum dispatch hours. We clarify that a request to allow a particular dual participation

[55] Joint DR Parties Opening Testimony at 9.

option should be accompanied with an explanation and methodology to demonstrate how the Incremental Load Reduction during overlapping event could be attributed uniquely to ELRP participation and avoid double compensation.

4.1.13. Balancing Accounts and Cost Recovery

PG&E, SCE and SDG&E shall continue to use the one-way balancing accounts authorized in D.21-03-056 regarding the development, implementation, and operation of the ELRP pilot program, along with incentives paid under the program.

This ELRP budget reflects projected costs for IOU program administration, including IT, evaluation, measurement, and verification costs, in addition to costs for compensating eligible customers who have contributed load reductions in response to an ELRP event.

Program Administration Budgets

These balancing accounts shall have the following annual caps for program administration across all ELRP sub-groups, *except* ELRP sub-group A.6 (Residential customers):

- PG&E $7.3 million,
- SCE $5.7 million, and
- SDG&E $3.0 million.

Additionally, these balancing accounts shall have the following caps for Residential ELRP (sub-group A.6) program administration and marketing, education, and outreach:

- PG&E:
    - 2022: $9.4 million for administration and $2.5 million for marketing, education, and outreach.

  - 2023: $8.7 million for administration and $2.0 million for marketing, education, and outreach.
- SCE:
  - 2022: $10.0 million for administration and $2.5 million for marketing, education, and outreach.
  - 2023: $9.0 million for administration and $1.6 million for marketing, education, and outreach.
- SDG&E:
  - 2022: $3.0 million for administration and $0.75 million for marketing, education, and outreach.
  - 2023: $2.7 million for administration and $0.5 million for marketing, education, and outreach.

Incentive Budgets

Additionally, these balancing accounts shall have the following annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, *including* the ELRP sub-group A.6 (Residential customers):

- PG&E $94.0 million,
- SCE $76.6 million, and
- SDG&E $30.8 million.

4.2. Residential ELRP

This decision adds a new Residential ELRP pilot as ELRP Group A.6 designed to extend to residential customers the opportunity to be compensated for their contribution to system reliability and load reduction during times of grid stress. The program will require IOUs to automatically enroll California Alternative Rates for Energy (CARE) customers and certain other groups of customers, and allow all other eligible residential customers to opt in to the program if they are not already enrolled in another supply side DR program or other programs detailed here. We order specific marketing and outreach for CARE customers and residents of Disadvantaged Communities.

4.2.1. Background of Residential ELRP

CEJA and PG&E each proposed a type of Residential ELRP in Phase 1, and the Staff Concept Paper contained a proposal as well. The staff proposal was as follows:

> **Expand Eligibility to Include Residential Customers:**
>
> Currently, most residential customers do not participate in [DR] programs that compensate them for load reductions, but the CAISO often depends on load reduction from residential customers through the Flex Alert program, which is a voluntary program that calls on social action to reduce demand but does not compensate individual customers. This raises questions of both equity and effectiveness given that the CPUC has developed numerous programs, including ELRP, that compensates non- residential customers for load reduction, but comparatively few programs for residential customers. Additionally, the voluntary Flex Alert program may have diminishing impacts over time as customer fatigue sets in. To address these possible concerns, Energy Division staff offers a proposal concept for consideration that all residential customers be considered eligible to participate in ELRP by default (except customers participating in existing supply-side DR programs). To implement this policy, the following proposal concept details are offered for CPUC consideration:
>
> i. All residential customers would be automatically enrolled in ELRP (except customers currently enrolled in supply-side DR programs). There would be no required sign-up or acknowledgment process.
>
> ii. The triggering requirements for these residential customers would be the CAISO calling a Flex Alert or Grid Alert in the day-ahead.
>
> iii. The Flex Alert marketing would be modified to promote ELRP event and to utilize all available channels to reach and notify customers about the imminent event and the

opportunity to reduce consumption and receive payment or bill credit.

iv. The payments for load reduction would be based on meter-verified Incremental Load Reduction . . . relative to a "simple" baseline to be established by the IOUs.

v. Program would be administered through the IOUs.

vi. IOUs and third-party DRP would still be permitted to target

vii. Residential ELRP customers to enroll them into their respective supply-side DR program, in which case the customer is removed from ELRP.[56]

4.2.2. Party Comments on Residential ELRP

CEJA and PG&E offered their own proposals, and parties commented on those proposals in Phase 1.[57] The scoping memo for Phase 2 made clear that those proposals would be part of the record for consideration of Residential ELRP.[58]

CEJA proposed a two-year, $20 million "Just Flex Rewards" program pilot to target low income and Disadvantaged Community households, allowing them to lower their energy consumption during ELRP events and be compensated for their participation. The proposal included automatic enrollment of all residential customers in Disadvantaged Communities and low-income customers. The

[56] Staff Concept Paper at 8-9.

[57] The following commenters submitted Opening Testimony on January 11, 2021 on a residential option during Phase 1: CEJA, PG&E, Small Utilities, CAISO, CalCCA, CARE, CBEA, CEERT, CESA, CLECA, DR Coalition, ecobee, GPI, Joint DR Parties, NRG, PCF, Peterson Power, Pioneer, Polaris, Public Advocates, SBUA, SCE, SDG&E, SEIA, Sierra Club, TeMix, TURN, UCAN, and VCE. Further, CEJA, PG&E, AReM, CAISO, CalCCA, Calpine, CARE, CEERT, CESA, CGNP, CLECA, DR Coalition, GPI, Joint DR Parties, PCF, Peterson Power, SBUA, SCE, SDG&E, Sierra Club, TEMIX, TURN, and UCAN submitted Reply Testimony on during Phase 1 on January 19, 2021.

[58] August 10, 2021 Scoping Memo at 5.

proposal prohibited dual enrollment in third-party and IOU DR programs. IOUs would alert customers of triggering events using the existing text messaging platforms they use for alerting customers to Public Safety Power Shutoff (PSPS) events.

Messaging would include information on actions to save energy, such as not running major appliances, turning up the temperature on air conditioning units, and turning off non-essential lights. The messaging would include requests to respond by a certain time indicating whether the household intends to participate and would allow customers to opt out of participation in the future. The community-based organizations that have been working with utilities related to PSPS events and the IOUs would consult with the joint CEC/CPUC Disadvantaged Communities Advisory Group about their materials describing the program to ensure that the materials are accessible and transparent to low-income customers and customers in Disadvantaged Communities. The IOUs would follow the guidance in the Commission's decision in R.18-10-007, ensuring that the materials are available in prevalent languages, and utilize the outreach findings that have been shown to be most effective in outreach surveys.

PG&E proposed its Power Savers Reward Program (PSRP), an out-of-market resource available through a variety of dispatch triggers. All residential customers, bundled and unbundled, with and without smart technologies in their homes, would be eligible to participate in the PSRP unless they are already enrolled in a DR program or on a critical peak pricing program. CAISO Alert, Warning, Emergency alerts and Flex Alert would trigger the programs. There would be special outreach and marketing to low-income customers and customers in Disadvantaged Communities.

PG&E proposed Options A, B and C. Under PG&E's proposed Option A, the approximately 1.6 million PG&E customers who receive Home Energy Reports and are not participating in Option B or any other DR or critical peak pricing program would receive alerts in advance of peak and near peak days to decrease energy use the next day. Pilot participants would receive educational energy communications, event day tips, and performance reports from PG&E. PG&E would implement a targeted marketing campaign to recruit customers who are low-income, CARE- or Family Electric Rate Assistance- (FERA) eligible, and in Disadvantaged Communities. This targeted population would receive a $10 annual end-of-season incentive for their participation. The incentives for low-income, CARE/FERA and Disadvantaged Community residential customers would equate to over $3 million per pilot year at $10 per customer based on a population of 696,000 customers.

PG&E's Option B would require that participants have qualifying technology such as a smart thermostat or the associated end-use appliance (*e.g.*, a central air conditioner, EV or heat pump water heater). PG&E would dispatch smart technologies during DR events and the devices would curtail energy use according to agreed-upon levels. The program would include pre-event cooling that would temporarily increase energy use to ensure the home is prepared for lower energy consumption during event hours. The pilot would initially focus on smart thermostats as their highest penetration rates will provide faster load reducing benefits. PG&E would test and assess flat incentive amounts versus pay-for-performance or end-of season incentives for cost-effectiveness and customer satisfaction.

PG&E's Option C for TOU customers would dispatch smart technologies according to a customer's TOU rate schedule. It is otherwise similar to Option B, but with a focus on ensuring the home is prepared for lower energy consumption during TOU hours. This option would be available to customers who have enrolled in Option B, are on a TOU rate, and have technology capable of automated response.

In Phase 2, parties provided comment on the CEJA, PG&E and Staff Concept Paper proposals that focused on the following areas. Comments in support of Residential ELRP included the observation that it restores some equity between Residential and non-Residential sectors in ELRP. They supported Residential customer compensation for voluntary load reductions, and observed that the program could provide an avenue for low-income customers and customers in Disadvantaged Communities to save on energy costs by being compensated for load reductions.[59] Others focused on the potential for Residential ELRP to increase awareness of energy usage and the need for load reduction for millions of customers.

CEJA supported an opt out program that would include all Residential customers, but also recommended special focus on informing low-income customers and customers in Disadvantaged Communities of the program.[60] Parties favoring an opt out option liked that it would ensure all residential customers were enrolled by default. Other commenters suggested an opt in

[59] CEJA Opening Testimony at 7; OhmConnect Opening Testimony at 8; Joint Parties Reply Testimony at 4, and SDG&E July 21, 2021 Reply to Supplemental Testimony at 2-5. *See also* PG&E July 7, 2021 Supplemental Testimony at 4 and 11, proposing a flat $10 incentive exclusively for Disadvantaged Community and low-income customers. PG&E's subsequent proposal supports incentives for all customers enrolled in the program; PG&E Opening Testimony at 3-2.

[60] CEJA Opening Testimony at 1-9; *see also* CEJA July 7, 2021 Supplemental Testimony.

approach on the ground it would create more buy-in to the program and help lead to intentional load reductions by customers.[61]

In Phase 2, each IOU also proposed its own program that would be extended to a subset of its residential customers, with PG&E proposing to enroll between 1.6 million and 3 million customers, SCE 1.8 million and SDG&E 0.5 million. SCE and SDG&E recommended a gradual rollout to ensure customers were not simply enrolled in a program without being aware of it, cautioning about free ridership.[62] PG&E did not oppose an opt out program for all residential customers.[63] Oracle and SDG&E also raised free ridership concerns, noting that customers could be compensated for actions that they would have taken without compensation.[64] However, Oracle highlighted a Baltimore Gas and Electric program similar to Residential ELRP, which addresses free ridership concerns through maximizing the awareness of the program and providing effective behavioral messaging.[65]

SCE proposed a Whole Home Savings Pilot that would auto-enroll high energy-usage customers who have opted in to receive transactional emails from SCE.[66] SCE proposes leveraging customer data to provide personalized tools to reduce energy usage and deploying a variety of marketing methods to educate customers and maximize participation.[67] SCE recommended $2/kWh incentives

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[61] SCE Opening Testimony at 67; SDG&E Opening Testimony, Mantz and McConnell at 18-21; *see* Oracle Opening Testimony at 10.

[62] SCE Opening Testimony at 67.

[63] PG&E Opening Testimony at 2-9.

[64] Oracle Opening Testimony at 10; SDG&E Opening Testimony, Mantz and McConnell at 20-21.

[65] Oracle Opening Testimony at 11. *See* CEDMC Opening PD Comments at 4.

[66] SCE Opening Testimony at 7-14.

[67] *Id.* at 11.

and the use of Flex Alerts or CAISO Grid Alerts as triggers.[68] SCE also proposed limiting dispatches to one event per day and 2 events per week, with static 2-hour events. SCE requested that customers be allowed to dually enroll in other residential DR programs.[69] Finally, SCE proposed a baseline method "Meter Before/Meter After" that measures the energy usage before and during the DR event.[70]

SDG&E did not develop its own proposal for a version of Residential ELRP. It described its existing "Peak Day" behavioral DR pilot program that provides tailored energy-saving suggestions and Home Energy Reports to approximately 525,000 customers that were previously auto-enrolled.[71] Events in DR occur between 4:00 – 9:00 p.m. during the summer. SDG&E is running its pilot using Oracle's platform, with a program similar to the program Oracle proposes. SDG&E is testing whether it can achieve peak reduction without the use of monetary incentives.[72]

Oracle supports a behavioral DR program where customers are asked to take specific actions to reduce energy use during the DR event, based on the individual customer's energy consumption. Soon after the DR event, customers would receive their performance results compared to their neighbors. The messaging would include tips and tools to reduce energy usage as well as

[68] *Id.* at 9-10.

[69] *Id.* at 8-9.

[70] *Id.* at 10.

[71] SDG&E Opening Testimony, Mantz and McConnell at 18-21.

[72] *Id.*

additional offerings, such as programmable thermostats to motivate customers to adopt automated technology and achieve deeper peak reductions.[73]

PG&E's program also includes individualized messaging to encourage reduction, thank you emails with performance reports, and additional tips and tools. PG&E believes its incentive proposal will motivate customers to take action on event days because they would be competing to earn points and receive compensation with electronic gift cards.[74]

Third-party DRPs expressed concern that an opt out option for Residential ELRP could dampen demand for their DR programs, and recommended either an opt in approach or a way for customers interested in enrolling in DR to easily disenroll from ELRP.[75] OhmConnect suggested that the IOUs be required to conduct an open enrollment period for third-party DR programs to serve as a conduit for customer enrollment in supply-side DR programs.[76] MCE opposed auto-enrolling CCA customers in ELRP on the ground it would cause customer confusion.[77]

Other comments focused on the high cost per kW of the program, the administrative and IT costs and challenge of implementing such a large program in time for 2022, limited flexibility of the resource since it is only available to be

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[73] Oracle Opening Testimony at 3.

[74] PG&E Opening Testimony at 2-6 – 2-7.

[75] Joint DR Parties Opening Testimony at 26; *see also* Joint Parties Opening Testimony at 9-10, Reply Testimony at 2 (additional third-party DR issues).

[76] OhmConnect Opening Testimony at 4-5; *see also* Joint Parties Reply Testimony at 5; TURN Opening Brief at 9-10.

[77] MCE Opening Testimony at 3-1 – 3-4.

dispatched on a day-ahead basis, and unknown cost impact because of the newness of the concept.[78]

Several parties supported special attention to residential customers in Disadvantaged Communities, low-income customers and customers eligible for the CARE and Energy Savings Assistance (ESA) programs. They asserted such customers would be motivated by the potential for bill savings due to their high energy burden.[79] CEJA also outlined a detailed proposal for outreach to these customers, requesting that customers be informed of the timeframe ELRP will be called, measures that can be taken to achieve reductions, and estimated bill credits if all measures are taken.[80]

Several parties expressed concern about the trigger for Residential ELRP of the CAISO-initiated Flex Alert, which taken together could suggest that the conditions under which Flex Alert is initiated could be re-examined and updated. Joint Parties do not support using Flex Alerts as a "hard" trigger because the conditions under which it is called are subjective.[81] CLECA expressed concern about Residential ELRP, in part because Flex Alerts are not always reflective of actual capacity shortages.[82] Multiple parties expressed concern with customer fatigue due to the frequency of Flex Alerts.[83] SCE supports limiting the Residential ELRP events to two hours and a maximum of 2

[78] SCE Opening Testimony at 66-67, and CLECA Opening Testimony at 3 and 8-9.

[79] OhmConnect Opening Testimony at 8; Joint Parties Reply Testimony at 4; *see also* CEJA Opening Testimony at 8 (supporting ELRP with modifications).

[80] CEJA Opening Testimony at 7-8.

[81] Joint Parties Opening Testimony at 11-12.

[82] CLECA Opening Testimony at 8. *See* CLECA Opening PD Comments at 2 (seeking clarification of its comments on Residential ELRP).

[83] CEJA Opening Testimony at 6; OhmConnect Opening Testimony at 6; PG&E Opening Testimony at 2-6; and SCE Opening Testimony at 65.

events per week because of its view that frequent Flex Alerts degrade customer confidence in the California electric grid, which could therefore impact the State's ability to achieve electrification and meet environmental goals.[84]

4.2.3. Adopted Residential ELRP Direction

This Commission has undertaken recent efforts to address affordability and promote equity in utility rates.[85] Expanding ELRP to residential customers will provide CARE customers and customers in Disadvantaged Communities an additional pathway to reduce their utility bills. Compensating customers who reduce their energy usage when called upon by the CAISO through the Flex Alert program will promote equity because many residential customers are already participating in the Flex Alert program and are not receiving compensation. We also expect to achieve greater load impact by providing monetary incentives, which is consistent with the stated goals of this proceeding.[86] Further, we see the value in creating a new program for residential

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[84] SCE Opening Testimony at 65.

[85] These affordability initiatives include:

- July 2020 - D.20-07-032, adopting metrics for assessing the relative affordability of public utility service;
- February 2021 - En Banc (all Commissioner meeting) to discuss staff white paper on affordability, strategies for cost control, and alternatives for funding climate change initiatives;
- April 2021 – Commission-issued affordability report that assesses the affordability of public utility service in California; and
- September 2021 – Scoping memo issued in affordability proceeding, R.18-07-006, opening a new phase in the proceeding to explore strategies to mitigate future energy rate increases.

[86] PG&E Opening Testimony at 2-7, stating that offering incentives could increase performance compared to its 2015-16 pilot using the Oracle platform that did not include incentives and only achieved a 0.04 to 0.07 kW load impact per customer; and OhmConnect Reply Testimony at 3, listing financial incentives as a critical component of achieving consumption reductions.

customers that will help them become more aware of their energy usage[87] and potentially gain confidence in the electric grid.

We adopt a four-year Residential ELRP pilot in which bundled and unbundled residential customers of an IOU are eligible to enroll in ELRP by opting-in to participate.[88] As discussed below, the IOUs shall automatically enroll (that is, apply an opt out approach to) certain groups of residential customers.

Customers may not simultaneously be enrolled in another supply side DR program offered by an IOU, third-party DR provider or CCA. However, customers may take service on a critical peak pricing, SmartRate or similar dynamic rate tariff and enroll in the Residential ELRP pilot because these programs are not visible to the IOUs.[89] Finally, a CCA may elect not to participate in the Residential ELRP pilot adopted here, in which case its customers would be ineligible to enroll.

We are not prepared to adopt a Residential ELRP that would automatically enroll all residential customers, and choose instead to allow most residential customers to opt in to such a program. We are somewhat concerned with the cost of compensating of customers for load reductions they might have had without such a program – the potential for free ridership. We are more concerned about the risk of low participation rates due to lack of customer buy-in as a result of automatic enrollment. For this reason, we support the IOUs'

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[87] *See* OhmConnect July 21, 2021 Reply Testimony at 2-3, using the term "energy engaged."

[88] The Residential ELRP pilot is identified as Group A.6 in Attachment 2 which accompanies this decision and contains all program requirements.

[89] A dynamic rate is both a rate program and an event-based DR program. *See* SDG&E PD Opening Comments at 9-10 (asserting that IOUs cannot verify whether a customer is in a CCA dynamic rate program).

targeted approaches of automatically enrolling customer segments that may already be engaged or would be easier to engage because they have chosen to receive transactional emails (SCE),[90] or already receive Home Energy Reports (PG&E and SDG&E).[91] We also support IOU efforts to create behavioral programs that provide game-like motivation to customers such as a variety of attractive marketing and education methods, personalized actions customers can take to save energy during events based on consumption data analysis, prompt follow up with performance results, point systems and alternative forms of payment like electronic gift cards.

We are also concerned with the cost of administering this program. The utility will need to track each enrolled customer, send messaging, provide customer service, and calculate event performance. Further, utilities need time to build a large-scale program. A pilot that does not automatically enroll all residential customers will allow the Commission to observe enrollment levels, customer complaints, load reduction and other outcomes before committing the entire population of residential customers to a program.

We are persuaded that disenrollment should be easy for customers. Customers participating in Residential ELRP may at any time enroll in a supply-side[92] DR program offered by the IOU, registered third-party DRP or CCA and shall be promptly unenrolled by the IOU from ELRP without the need

[90] SCE's Whole Home Savings Pilot; SCE Opening Testimony at 7-14.

[91] PG&E's PG&E proposed a Power Saver Rewards Pilot; PG&E Opening Testimony at 2-9; and SDG&E Peak Day program; SDG&E Opening Testimony, Mantz and McConnell at 20-21.

[92] Supply-side programs are integrated into the CAISO market(s).

for any action on the part of the customer.[93] Customers can also opt out of the program through a simple process. Similarly, eligible customers should be able to opt in to an IOU's Residential ELRP pilot easily. We decline to order an open enrollment period for DR programs as OhmConnect requests, given the limited time to summer 2022.

The following IOU programs that auto-enroll sets of select customers are approved, as modified herein, as each IOU's Residential ELRP pilot for the duration of the pilot:

- PG&E's Power Savers Rewards Program, Option A, with auto-enrollment of customers who receive PG&E's Home Energy Reports. PG&E's Options B and C are not approved.
- SCE's proposed Whole Home Savings Pilot, with auto-enrollment of "high usage customers who have opted in to receive transactional emails." Dual participation is not permitted at this time.
- SDG&E's existing "Peak Day" Behavioral DR program, with auto-enrollment of "existing Home Energy Report . . . customers," may serve as the basis for SDG&E's select group of customers who will be auto-enrolled into Residential ELRP.[94]

In addition to the IOU-specific auto-enrolled set of select customers specified above, the IOUs shall auto-enroll residential customers in the CARE

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[93] SDG&E's point in its Opening PD Comments at 9-10 that the IOU does not know if a customer is enrolled in a CCA's DR program is not correct for market integrated or supply-side DR programs. The IOU in its role as Utility Distribution Company (UDC) tracks a customer's location registration in the CAISO Demand Response Registration System (DRRS). Whenever a customer is entered into the DRRS, the UDC must validate that the customer does not participate in an IOU DR program. If the IOU sees that a CCA or third-party DR provider registers a customer location in the DRRS, the IOU at that time should unenroll the customer from the Residential ELRP pilot. *See* Electric Rule 24 (PG&E and SCE) and 32 (SDG&E).

[94] *See* SDG&E's Opening PD Comments at 12.

program and the Family Electric Rate Assistance program (FERA). In comments on the Proposed Decision, CEJA and the Sierra Club[95] recommended auto-enrolling ESA program participants.[96] We decline to adopt this proposal and instead enroll FERA customers because unlike CARE and FERA which are ongoing rate assistance programs, ESA customers have little ongoing participation after energy efficiency and other savings measures are installed in their homes. Thus, CARE and FERA are a good proxy for ESA customers, and indeed capture more customers than would ESA.

The IOUs shall provide notifications to alert and engage customers about the program being triggered using methods such as email, phone call, text message, bill insert or mailer. Customers may also opt out of Residential ELRP at any time.

In their marketing, education, outreach, and event notification efforts focused on the foregoing auto-enrolled customers and customers in Disadvantaged Communities, the IOUs shall incorporate elements of CEJA's Just Flex Rewards proposal including both in-language accessibility, and specific outreach for CARE, ESA, FERA and Disadvantaged Community customers, as described in Attachment 2 to this decision.

IOUs shall use a day-ahead CAISO-issued Flex Alert or Grid Alert (*i.e.*, the "Alert" stage of CAISO's Alert, Warning, Emergency signal)[97] declaration as the trigger for dispatching Residential ELRP customers, in addition to the Group A

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[95] CEJA/Sierra Club Opening PD Comments at 12.

[96] The ESA program provides energy efficiency and other measures to low-income households.

[97] *See* SDG&E Opening PD Comments at 5-6; PG&E Reply PD Comments at 1-2 (seeking clarification that the Day Ahead alerts are at issue); CEDMC Opening PD Comments at 5-6 and AEE Reply PD Comments at 4 (seeking clarification that the CAISO Grid Alert, the "A" grid alert in the CAISO's Day Ahead Alert, Warning, Emergency alert program, also triggers ELRP).

triggers described below. To provide more predictability for stakeholders regarding the conditions and parameters under which CAISO will issue a Flex Alert notice, this Commission's Energy Division staff will work with CAISO to develop an objective set of criteria that triggers Flex Alerts.[98] We request that any changes be made in time for the 2022 ELRP season.

The IOUs shall establish a process for a CCA to inform the IOU of its election to exclude its customers from ELRP. The CCA must make its election by January 31 of a new ELRP pilot year.

The IOUs shall collaborate to establish common program parameters, including a minimum dispatch window (which must be at least 2 hours), the start time of the dispatch, marketing strategies that limit customer confusion by ensuring that individualized messaging from the IOUs is consistent with the messaging from the statewide Flex Alert campaign, and statewide unified branding. Each large IOU shall file a Tier 2 Advice Letter within 60 days[99] of issuance of this decision to establish the parameters and proposed cost of its ELRP Residential pilot program. In the Flex Alert paid media campaign portion of this decision, below, we also address marketing for Residential ELRP for 2022 and 2023.

The IOUs have discretion to determine the proper baseline against which load reductions will be calculated and compensation paid. We are concerned about SCE's Meter Before/Meter After proposal[100] because it could exclude

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[98] *See* CAISO Opening PD Comments at 4.

[99] We extended the filing date for this Advice Letter from 30 days to 60 days. *See* SDG&E Opening PD Comments at 12.

[100] TURN supported SCE's baseline approach. TURN Opening PD Comments at 4-6; TURN Reply PD Comments at 3-4. PG&E supported not prescribing a baseline. PG&E Reply PD

Footnote continued on next page.

customers who actually participated in an ELRP event such as customers who pre-cool their homes or use other strategies that should be encouraged.
One example is a customer who turns off all her lights and air conditioning at 2:00 p.m. to go to shopping in her community in preparation for an event scheduled for 4:00 - 6:00 p.m. SCE's proposal would not reward this customer because energy usage would be measured only during the hour before the event and during the event. Therefore, the IOUs shall evaluate the baseline methodology after the first program year, as CEJA/Sierra Club suggest.[101] The IOUs shall submit a joint report to the Commission's Energy Division no later than January 15, 2023, with a copy to the service list for this proceeding, reminding parties of this requirement and outlining their approach to the evaluation.

PG&E, SCE and SDG&E may continue to use the one-way balancing accounts authorized in D.21-03-056 to record costs of the Residential ELRP program, including costs of development, implementation, and operation of the program along with incentives paid under the program. These balancing accounts shall have the following annual caps for the Residential ELRP, with additional allowances for the increased scope of customers that will be auto-enrolled compared to IOU proposals. The approved administrative and Marketing Education and Outreach (ME&O) caps are shown below. While these caps are listed by year, the IOUs may shift funds between 2022 and 2023 as

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Comments at 2. CEJA/Sierra Club advocated for evaluation of the baselines in a year, an approach we adopt. CEJA/Sierra Club Opening PD Comments at 12.

[101] CEJA/Sierra Club Opening PD Comments at 12.

needed,[102] but shall not use this flexibility simply as a means of justifying a request for more funding in 2023:

Residential ELRP A.6 Budgets by Category*						
(in $Millions)	**PG&E**		**SCE**		**SG&E**	
	2022	2023	2022	2023	2022	2023
*Administrative – Systems & IT, Notifications, Labor, Measurement & Evaluation***						
Requested Admin Budget	*$ 9.4*	*$ 8.7*	*$ 17.4*	*$ 11.1*	*$ 3.3*	*$ 3.0*
Approved Admin Budget	**$ 9.4**	**$ 8.7**	**$ 10.0**	**$ 9.0**	**$ 3.3**	**$ 3.0**
Marketing, Education & Outreach (ME&O)						
Requested ME&O Budget	*$ 0.5*	*$ 0.5*	*$ 5.4*	*$ 1.6*	*NA*	*NA*
Approved ME&O Budget	**$ 2.5**	**$ 2.0**	**$ 2.5**	**$ 1.6**	**$ 0.75**	**$ 0.5**
Annual Totals	$11.9	$10.7	$12.5	$10.6	$4.05	$3.5
Totals Per IOU	$22.6		$23.1		$7.55	

**Not including incentives, which are included in the combined incentive budget for all ELRP groups.*
*** Not including Rule 24/32 third-party systems & IT costs.*

4.3. Modifications to IOU DR Response Programs

4.3.1. Cost Effectiveness

As directed in D.21-03-056, the use of our traditional cost-effectiveness tools is waived for all DR proposals adopted in this decision for years 2022 and 2023, under certain conditions. Regarding changes to existing DR programs adopted in this decision, the IOUs have proposed to use their existing DR budgets to fund many of those changes, which will help mitigate potential impacts to ratepayers. Any changes that require new incremental funding must

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[102] SDG&E requested this flexibility, which is reasonable as long as it is not used as a basis to request for more funding for 2023 because the IOU has used up the budget in 2022. *See* SDG&E Opening PD Comments at 11. We also add $0.6 million to SDG&E's budget for measurement and evaluation of the pilot. *See id.*

be tracked in the memorandum accounts authorized in D.21-03-056, and requests for cost recovery will undergo reasonableness review.

4.3.2. Cost Recovery

As directed in D.21-03-056, PG&E, SCE and SDG&E shall continue to utilize unspent funds from their existing DR budgets adopted in D.17-12-003, to the extent existing funds are available.

To the extent that any tariff amendments are necessary to effectuate the DR program changes ordered in this decision, those changes should be documented in a Tier 1 Advice Letter, as well as the process for transferring balances within the IOU's DR Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

4.4. Modifications to DR Programs that Apply to All IOUs

4.4.1. Procurement of DR Resources from Third-Party DR Providers

The IOUs shall procure RA capacity from eligible third-party DRPs for 2022 and 2023 deliveries through bilateral contracts.[103] We agree that given the time constraints set in this proceeding, bilateral contracts would allow the IOUs to tailor the contracts to their specific needs. The procured DR capacity shall count toward the overall MW targets established for each IOU in this decision. Because these procured resources are incremental to IOUs' and all LSEs' 15% PRM, these resources would not be applied to any LSEs' Maximum Cumulative Capacity (MCC) bucket cap calculation.

The third-party DR resources procured by the IOUs shall be comprised of new resources incremental to all DR resources already committed, in existing DR

[103] Joint Parties Opening Testimony at 18 and TURN Reply Testimony at 19.

contracts and programs, to any LSE. These resources shall be integrated into the CAISO markets as economic DR (under a Proxy Demand Resource product) and must abide by all RA and CAISO rules. For the purposes of this emergency related procurement only, the DRPs are not required to have completed the Load Impact Protocol process for the DR resources procured by the IOUs. The procurement shall be informed by the DRPs' past performance.

The IOUs shall include performance requirements in their purchase agreements with the DRPs. To standardize payment/penalty requirements in these contracts, the IOUs shall adopt the capacity payment and penalty structure from PG&E's Capacity Bidding Program (CBP). We clarify that the CBP payment and penalty structure will govern the contract payment framework. The capacity price of the contracts will be established by the procurement process.

4.4.2. Auto DR Customized Incentives

The IOUs are authorized to pay upfront 100% of the eligible incentives for a custom Auto DR project on the condition that the customer's enrollment commitment to participate in an eligible DR program is extended from three years to five years. This modification is effective for 2022 and 2023 only.[104] The Auto DR eligibility criteria for DR programs remain unchanged.

SCE proposed reversing the policy set in D.12-04-045 in order to increase program enrollment and cited a 2020 joint IOU study performed by Energy Solutions that found the 60/40 incentive split is a major barrier to participation as it does not align with customer business models and adds uncertainty to customers' financial planning.[105]

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[104] SCE Opening Testimony at 40-43.

[105] SCE Opening Testimony at 40-43.

Polaris supports eliminating the 60/40 incentive split. Polaris does not support extending the participation requirement from three to five years, indicating it is beyond most commercial planning and DR cycles, which means programs could change twice before the commitment ends. Further, it notes that irrigation automation represents about half of the program megawatts in recent years. Polaris notes that farmers are struggling and may be forced to fallow land while still being required to pay the incentive back or face a claw back of the incentive payment.[106]

TURN supports eliminating the 60/40 incentive payment split for custom Auto DR incentives and the extension of the enrollment requirement from three years to five years. TURN indicates this will help expedite the movement toward automated DR.[107]

The Joint Parties support eliminating the 60/40 incentive split for custom Auto DR incentives and the extension of the enrollment requirement to five years calling the latter "a reasonable step toward balancing out any incremental risk that the Commission may perceive as a result of the transition back to an up-front incentive structure."[108]

4.4.3. Capacity Bidding Program

We clarify that the alternative baseline adjustment option allowed by CAISO and already authorized for use in IOU Capacity Bidding Programs and Demand Response Auction Mechanism in D.21-03-056 can be used for calculating capacity performance in their respective Capacity Bidding Programs and Demand Response Auction Mechanism.

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[106] Polaris Reply testimony at 6.

[107] TURN Reply testimony at 16.

[108] Joint Parties Reply testimony at 14.

The Joint Parties propose the Commission explicitly authorize use of the CAISO's new baseline options for CBP and DRAM capacity settlement.[109] The Joint Parties indicate that D.21-03-056 was unclear whether the intent of the Commission was that the CAISO's alternative baseline be applicable to energy market settlement only or capacity settlement also. The Joint Parties want the Commission to specify that the CAISO's alternative baselines are applicable to the calculation of CBP capacity incentive payment and DRAM contract payments – and that the Commission requests the CAISO extend its alternative day-of adjustment factor for the May-October 2022 and 2023 term.

TURN agrees with the Joint Parties that the Commission should explicitly authorize use of the CAISO's new baseline options for CBP capacity incentive payments and DRAM contract payments saying it's "reasonable and sensible and should be adopted."[110]

The Joint DR Parties agree with the adoption for all Capacity Bidding Programs this alternative baseline adjustment.[111]

4.5. Modifications to PG&E's DR Programs, Pilots, and Related Support Programs

PG&E's proposal to implement a price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 is approved. PG&E notes that "during the August 2020 heatwave a number of CBP Aggregators elected to bid their resources at, or close to, the CAISO's maximum bid price of $1,000/MWh, which resulted in about 45 percent of CBP resources not being dispatched. Had a bid cap of $650/MWh been in place, all nominated

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[109] Joint Parties Opening Testimony at 30.

[110] TURN Reply Testimony at 22.

[111] Joint DR Parties Reply Testimony at 5.

CBP resources would have been dispatched at least once during the August 2020 heatwave."[112]

PG&E's proposal to increase the current Base Interruptible Program (BIP) compensation level by $1/kW for the months of May through October for the years 2022 and 2023 is approved. PG&E notes that "[t]he reason[s] for the proposed increase is driven by a desire to encourage enrollment, recognize greater opportunity costs during the peak season (May-October), and to help 'minimize loss of DR enrollment.'"[113] This $1/kW seasonal increase is unique to 2022 and 2023 as justified by the Governor's July 30, 2021 Emergency Proclamation, and is not intended to continue beyond 2023.

Both the Joint DR Parties and the Joint Parties supported the increased incentive for BIP, although they proposed an even higher increase in compensation. We were not compelled to go beyond the proposal of PG&E.

PG&E's proposal to create and manage a new out-of-market residential smart thermostat control pilot program is approved for 2022 and 2023. PG&E is authorized to spend an incremental $17.5 million in incentives, administration, and marketing in 2022 and 2023 for this pilot. For the program to continue beyond 2023, this program must be market integrated (as supply-side DR).[114]

PG&E is authorized to replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program. PG&E is authorized an incremental $7 million in funding in 2022 and 2023 for administration, marketing, and retention incentives for this device exchange.[115]

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[112] PG&E Opening Testimony at 4-1.

[113] PG&E Opening Testimony at 4-2.

[114] PG&E Opening Testimony at 4-6 to 4-10.

[115] PG&E Opening Testimony at 4-4 to 4-6 and 4-10.

The Joint Parties support exchanging one-way technology, and a one-time $25 retention payment [included in PG&E's proposal and budget].[116]

PG&E's request for $1.2 million in incremental funds for Information Technology system enhancements to support third-party DR is approved, and PG&E may use the one-way balancing account authorized in D.21-03-056 to track these expenses.[117] We support this request for funding authorization to assist PG&E in improving the scalability and performance of its systems that support third-party DR customers, which should support leveling the playing field between third-party and IOU DR.

4.6. Modifications to SCE's DR Programs, Pilots, and Related Support Programs

Non-residential customers enrolled in SCE's Summer Discount Program (SDP) are permitted to dual participate in ELRP under the customer subgroup "A.1. Non-Residential, Non-DR Customers," and are not subject to the Minimum Size Threshold of subgroup A.1.[118] We agree that this modification will increase enrollment and decrease attrition.

SCE's proposal to reinstate the pre-cooling strategy where applicable in its Smart Energy Program (SEP) is approved. TURN supports this proposal.[119] SCE notes that "[p]re-cooling of homes can also help slow the deterioration of load impacts by extending the amount of time it takes the home to warm to its event

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[116] Joint Parties Reply Testimony at 11.

[117] PG&E Opening Testimony, p. 5-3 to 5-9.

[118] SCE Opening p. 17-20.

[119] TURN Reply Testimony at 24.

setpoint. Pre-cooling can also reduce participant opt-outs through increased participant comfort."[120]

SCE's proposal to increase the ME&O budget for its SEP by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness is approved.[121]

SCE is authorized to recover from the memorandum accounts authorized in D.21-03-056 additional costs that occur in Smart Energy Program due to the new smart thermostat incentive program adopted in this decision.

To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for reliability DR resources (RDRR), SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that 1) the BIP and Agricultural Program-Interruptible (AP-I) parameters match, and 2) the parameters for the SDP and SEP match is approved.[122]

CLECA agrees with SCE that the CAISO RDRR market enhancements are sub-optimal.[123]

4.7. Modifications to SDG&E's DR Programs, Pilots, and Related Support Programs

SDG&E is authorized to continue in 2022 its CBP residential pilot approved in D.21-03-056.[124]

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[120] SCE Opening Testimony at 23 referencing the 2020 Smart Energy Program Load Impact Evaluation at 30.

[121] SCE Opening Testimony at 22-24.

[122] SCE Opening Testimony at 49.

[123] CLECA Reply Testimony at 5-7.

[124] SDG&E Opening Testimony, Mantz and McConnell at 13.

SDG&E is authorized to create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives as proposed by SDG&E. SDG&E is authorized to use existing funding for 2022, and is authorized $1.6 million for 2023, as well as a $51,000 incremental marketing budget.[125]

Joint DR parties say they "applaud San Diego gas and Electric Company's proposal to add an Elect option to SDG&E's CBP program." They note that SDG&E's proposal is less flexible than PG&E's option, but that it is "still a significant enhancement to SDG&E's CBP program."[126]

4.8. Flex Alert Paid Media Campaign

This decision requires continuation of the Flex Alert paid media campaign ordered in D.21-03-056 for the summers of 2022 and 2023, with two changes. First, the budget for 2022 and 2023 shall be $22 million, which represents the same budget as approved for 2021 ($12 million), plus $10 million in additional ratepayer funding that matches a $10 million appropriation for the program from the State General Fund approved in the 2021 Budget Trailer Bill, Assembly Bill 128.[127] Second, the Flex Alert campaign shall include marketing of the new Residential ELRP pilot adopted in this decision.

4.8.1. Background of the Flex Alert Proposal

The Staff Concept Paper proposed that if the Commission extended the ELRP pilot to residential customers, the Flex Alert campaign should be modified

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[125] SDG&E Opening Testimony, Mantz and McConnell at 13-15.

[126] Joint DR Parties Reply Testimony at 4.

[127] Stats. 2021, Ch. 21, Sec. 2.00, subd. 8660-001-0001, item 2 ("The Public Utilities Commission or its delegee may award or designate funding in the amount of $10,000,000 from the General Fund in support of the Flex Alert program to achieve the purposes contemplated in Decision 12-03-056 [sic; should be Decision 21-03-056].").

to "promote ELRP event[s] and to utilize all available channels to reach and notify customers about the imminent event[s] and the opportunity to reduce consumption and receive payment or bill credit."

The Phase 1 decision and record are useful to understand the Flex Alert program ordered for 2021 and 2022. A December 18, 2020 ruling in Phase 1 attached a staff proposal for the campaign with the following characteristics:

- Electric IOU participation in a paid media Flex Alert campaign using ratepayer funds for the purpose of mitigating the need for rotating outages;
- Contract management through a contract between one electric IOU and a marketing agency;
- Solicitations for marketing vendors in the early spring of 2021 and launch of the program for the summer of 2021; and
- A contract for the summers of 2021 and 2022.

Decision 21-03-056 directed the implementation of a statewide Flex Alert program available for the summers of 2021 and 2022. It required SCE to contract with vendor DDB San Francisco for a two-year period and conduct a performance assessment during year two (2022). The decision directed SCE, PG&E and SDG&E to fund the campaign with funds collected from all benefitting customers (*i.e.*, bundled IOU, CCA and Direct Access customers) using Public Purpose Program balancing accounts. The decision authorized a budget of $12 million per year, for two years, to support the campaign, allowing up to 3% of the annual Flex Alert budget to cover IOU administration costs.

4.8.2. Party Positions on the Flex Alert Proposal

Comments on Flex Alert were few since the program has already been ordered for 2021 and 2022. SCE proposed its own program,[128] and the California Efficiency + Demand Management Council (CEDMC) and CEJA recommended that the Flex Alert marketing include CEJA's Just Flex Rewards program, which mirrors the Residential ELRP this decision orders.[129]

4.8.3. Adopted Flex Alert Direction

We adopt a continuation of the Statewide Flex Alert paid media campaign funded by the ratepayers of PG&E, SCE and SDG&E for 2022-2023, with a budget of $22 million in each year. The IOUs shall expand the campaign to include the Residential ELRP campaign as described below and in Attachment 1. (Additional Residential ELRP details appear in Attachment 2.)

The 2021 fiscal year (year one) budget was $12 million in ratepayer funds, and an additional $10 in General Fund dollars for fiscal year 2021-22, which was implemented through a separate contract executed in 2021. A $22 million budget for 2022 and 2023 is reasonable due to the conditions described in this order, which justify keeping marketing levels steady, especially with the added marketing we order for the new Residential ELRP pilot.

SCE shall revise the existing contract with the Statewide Marketing, Education and Outreach vendor DDB San Francisco (ME&O vendor) to increase the 2022 fiscal year (year two) budget to $22 million each year, as it is now in the amount of $12 million. SCE shall also revise the existing contract with the ME&O vendor to extend the paid Flex Alert Media campaign through

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[128] SCE Opening Testimony at 11.

[129] CEDMC Reply Testimony at 5-8; CEJA Opening Testimony at 7.

December 31, 2023 at the same budget of $22 million per year. If for some reason additional funds become available for fiscal year 2022 or 2023, SCE shall amend the program to incorporate that additional funding.

SCE shall execute a contract with the ME&O vendor within 60 days of the effective date of this decision to allow for adequate program implementation for the 2022 summer months. SCE shall seek and follow direction from the Commission's Energy Division staff on the scope of and budget for the amended contract, and during the implementation and administration of the contract. The contract shall terminate on December 31, 2023, unless the Commission orders the contract extended.

The Flex Alert campaign shall include marketing messaging and materials for the new Residential ELRP pilot adopted in this decision. To support the Residential ELRP pilot, the Flex Alert campaign should include messaging for day-ahead Flex Alerts, as well as day-ahead Grid Alerts (*i.e.*, the "Alert" stage of CAISO's Alerts, Warning, Emergency signal).[130] The campaign should also discourage use of BUGs using prohibited resources for Residential ELRP customers. Energy Division will work with the ME&O vendor on the specific messaging regarding triggers and BUGs, as well as other aspects of the campaign.

PG&E, SCE and SDG&E shall fund the campaign for 2022 and 2023 with funds collected from all benefitting customers in their service territories (*i.e.*, customers of the bundled IOUs, CCAs, Electric Service Providers and Direct Access providers) using Public Purpose Program balancing accounts. The

[130] Although the Proposed Decision did not make clear that the Day Ahead Grid Alert was a trigger for Residential ELRP, Attachment 2 to this decision did make this clear, so the decision has been clarified to include this trigger. *See* CEDMC Opening PD Comments at 5-6; AEE PD Reply Comments at 4.

budget is allocated based on each IOU's portion of the CPUC jurisdictional share of CAISO peak load: 45% for SCE, 45% for PG&E, and 10% for SDG&E.

We authorize IOUs up to 3% of the annual Flex Alert paid media campaign budget to cover IOU administration costs. If needed, the IOUs may request continuation of the funding and contract for the campaign beyond December 31, 2023, to support ELRP in the IOU DR application proceeding we anticipate opening in May 2022.

In all other respects, the Flex Alert campaign shall continue in its current form into 2022, including use of Community Based Organizations to assist with marketing in Disadvantaged Communities.

4.9. Smart Thermostats

This decision authorizes a budget of up to $22.5 million in technology incentives ($75 per thermostat) to develop a limited, two-year Residential Smart Communicating Thermostat program for 2022-2023 to incentivize the installation of up to 300,000 smart communicating thermostats (smart thermostats or smart thermostat) in hot climate zones, specifically, climate zones 9, 10, 11, 12, 13, 14 and 15. As described below, the climate zone limitations do not apply to smart thermostats installed under the ESA program. To ensure the smart thermostats actually control air conditioning load in times of emergency, the program will require customers, except those qualified for ESA, to pre-enroll in a CAISO market integrated supply-side DR program. This program will be run statewide within each IOU's service territory, and the IOUs may request up to an additional 10% of the technology incentive budget of each IOU's proportional share for administrative costs.[131] Fifty percent of the technology incentive

[131] In response to comments by the IOUs on the Proposed Decision, we clarify that the budgets are proportional to the IOUs' share of the market and that each IOU will run the program in its

Footnote continued on next page.

budget, or up to $11.25 million, will be available to DRPs to provide rebates through third-party DR programs. DRPs should have competitively equal access to the rebates as the IOUs.[132]

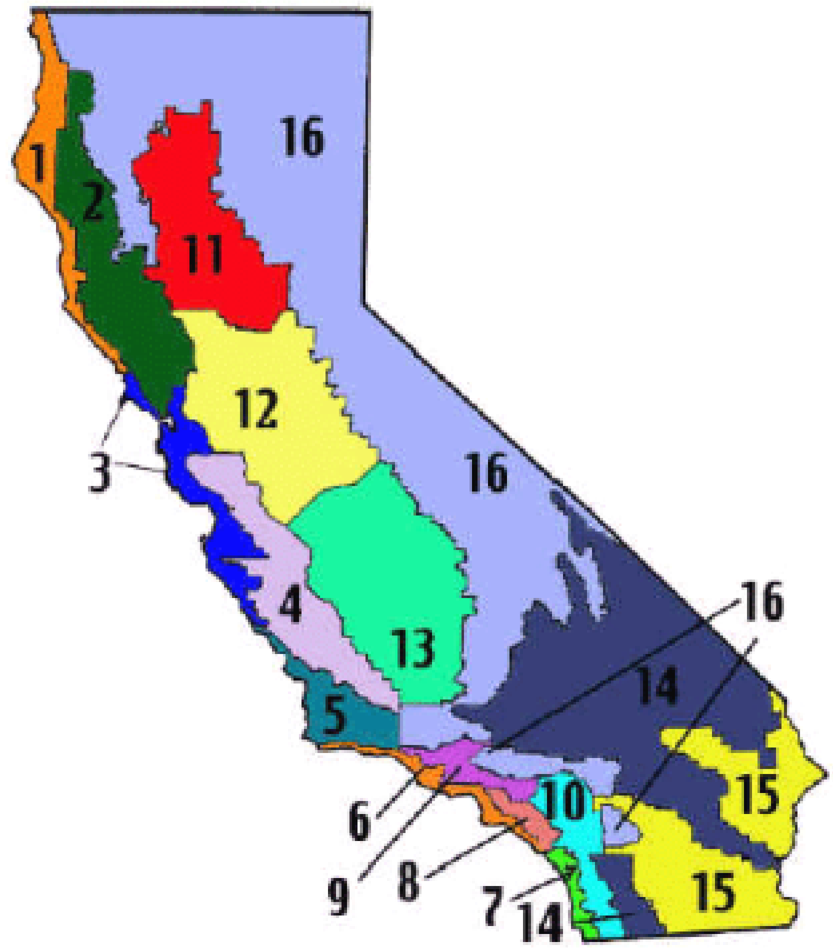
4.9.1. Background on Smart Thermostats

Air conditioning load increases substantially in the summer months, and especially in hot climate zones. Climate zones 9, 10, 11, 12, 13, 14 and 15 appear on the following map in Figure 1, and generally represent the California Central Valley, inland portions of the Bay Area and inland regions in Southern California. When reliability emergencies occur, control of air conditioner use in those areas – within the boundaries of customer health and safety – could help reduce demand. Smart thermostats, when combined with a market-integrated, supply-side DR program, will automatically turn down air conditioning (*i.e.*, increase the temperature by a few degrees) during reliability events and thus reduce electric load.

Figure 1. Climate Zone Map

territory. That is, the three IOUs shall proportionally divide the 10% amount, or $2.5 million total, according to market share. SDG&E Opening PD Comments at 14; SCE Opening PD Comments at 9; PG&E Opening PD Comments at 7.

[132] *See* Joint Parties Opening Testimony at 20-25.



In its Staff Concept Paper, Energy Division proposed a program like the one adopted here, reasoning that focusing on hot climate zones would deliver the highest potential energy savings for smart thermostat measures.[133] Staff also observed that smart thermostat programs have the potential to provide significant demand savings when paired with existing [DR] programs. By focusing smart thermostat installations to climate zones that have demonstrated the highest energy savings and pairing them with a DR program, a higher amount of savings and reliability is expected.

[133] Staff Concept Paper, Section 8.

For income-qualified customers eligible to participate in the Commission's ESA program, staff noted that smart thermostat subsidies are already available for those customers in all climate zones. There, the Staff Concept Paper proposed retaining such subsidies, and also making participation in a supply-side DR program voluntary, but encouraged:

> 1. Continue to allow smart thermostats in all climate zones with potential voluntary participation in the supply-side DR program. [The Energy Savings Assistance Program] makes smart thermostats available to all eligible customers across all climate zones for PG&E, [SCE and SDG&E] service territory. Due to the program design, it is recommended that this be allowed to continue.
> 2. For hotter climate zones that currently allow central Air Conditioning . . . measures (and potentially paired with insulation measures) as well as smart thermostats, include voluntary participation in the supply-side DR program.[134]

4.9.2. Party Comments on Smart Thermostats

Many parties addressed smart thermostat programs, proposing their own programs and responding to the staff proposal. Some opposed limiting the programs to hot climate zones, preferring a program that would be available to customers in all climate zones.[135] Recurve urged focusing smart thermostat efforts on the 4:00 p.m. – 9:00 p.m. window where reliability concerns most often appear, but otherwise not limiting eligible climate zones.[136] SCE proposed raising the smart thermostat incentive payment to $125 (or the full amount of the device, whichever is less), to help ensure customers will actually buy the

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[134] Staff Concept Paper at 16.

[135] SDG&E Opening Testimony, Mantz and McConnell at 27-28, Joint Parties Opening Testimony at 18; Google Opening PD Comments at 3.

[136] SCE Opening Testimony at 27.

thermostats.[137] The Joint Parties supported a program that ensures third-party DRPs can participate.[138]

As for ESA-eligible customers, PG&E supported the staff concept to allow smart thermostat incentives in all climate zones given that the Commission has already authorized such payments in its ESA decisions. CEJA requested a thermostat incentive payment of $200 with bill rebates for load reduction, while Grid Alternatives proposed a program roll-out to 70,000 customers.

A requirement of enrollment in a DR program was supported by Google Nest, with an option to opt out of the DR program and forego the smart thermostat rebate.[139] PG&E opposed mandatory DR program enrollment, alluding to a new program it plans to roll out.[140]

4.9.3. Adopted Smart Thermostat Direction

We adopt a smart thermostat program designed to achieve load reduction in hot climate zones. The program will subsidize the smart thermostat devices, and require that a customer, including an ESA or CARE-eligible customer choosing to receive a smart thermostat through this program,[141] pre-enroll in a CAISO market integrated DR program that is administered by either an IOU or third-party DR provider. We authorize up to $22.5 million in technology incentives to be available over a two-year period, from 2022 to 2023. The

[137] Recurve Opening Testimony at 16.

[138] SCE Opening Testimony at 27.

[139] Joint Parties Opening Testimony at 20-25.

[140] Google Nest Opening Testimony at 8, Appendix B.6.

[141] Comments on the PD requested extending eligibility to CARE as well as ESA customers, and allowing such customers to choose between the new program adopted here or the ESA thermostat program. *See* CEDMC Opening PD Comments at 10-11; Google Opening PD Comments at 6-7; Leap Opening PD Comments at 6.

program rebate amount for participants of $75, not to exceed the full cost of the equipment, shall be uniform across all program implementers. The program will be available for customers in climate zones 9, 10, 11, 12, 13, 14 and 15. The IOUs shall jointly file a Tier 2 Advice Letter with details of the program as further described below.

We are not persuaded that an emergency smart thermostat program in cooler coastal zones will deliver meaningful energy savings. Indeed, many smart thermostat incentives have been distributed to customers in cooler climate zones, with minimal load reduction.[142] However, the Commission has already adopted smart thermostat incentives for CARE/ESA-eligible customers without a DR requirement and we continue that authorization here, as described below.

Fifty percent of the technology incentive budget, or up to $11.25 million, will be available to third-party DRPs to provide rebates through the third-party supply-side DR programs. The third-party DRPs should have competitively equal access to the rebates as the IOUs. IOUs may request up to an additional 10% of the technology incentive budget of each IOU's proportional share for administrative costs.[143] Each IOU must justify the amount of administrative budget that will be required to administer the program in the joint Tier 2 Advice Letter filing this decision requires.

The technology incentive amount will be up to $75 per smart thermostat, or the full cost of the smart thermostat, whichever is less. This incentive amount

[142] Impact Evaluation of smart thermostats Residential Sector - Program Year 2018, CPUC, https://pda.energydataweb.com/api/view/2339/CPUC%20Group%20A%20Report%20Smart%20Thermostat%20PY%202018_PDA.pdf.

[143] *See* SDG&E Opening PD Comments at 14; SCE Opening PD Comments at 9; PG&E Opening PD Comments at 7.

is similar to that authorized in previous Commission programs,[144] reflecting our belief that subsidizing up to the entire smart thermostat cost will increase program participation. This technology incentive of $75 is not intended to be combined or "stacked" with thermostat technology incentives provided by the existing Auto Demand Response program.[145] Prior to incentive payment, the IOUs must certify installation of an eligible thermostat and enrollment in an eligible IOU or third-party supply-side DR program. Eligible market integrated programs are the Demand Response Auction Mechanism, Smart Energy Program, Capacity Bidding Program-Residential, and AC Saver.[146]

Within 15 days of issuance of this decision the IOUs shall meet and confer with third-party DRPs to discuss the process to distribute rebate awards, and to certify smart thermostat installation and DR program enrollment. The IOUs may use existing processes for reimbursing customers to avoid operational challenges and delays.[147] Within 45 days of issuance of this decision, the IOUs shall jointly file a Tier 2 Advice Letter that reflects a consensus across third-party DRPs and IOUs on the foregoing issues. The joint Advice Letter shall include the following items:

- Program design and budget;

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[144] *See, e.g.,* D.17-12-003 at 82.

[145] PG&E erroneously assumed stacking of incentives is allowed. PG&E Opening PD Comments at 7; *see also* SCE Opening PD Comments at 8; CEDMC Reply PD Comments at 5 (supporting stacking); Google Reply PD Comments at 1-3 (supporting stacking); OhmConnect Reply PD Comments at 3-4 (seeking clarification on stacking).

[146] CEDMC asked for clarification of eligible programs in comments on the Proposed Decision, which we provide here. CEDMC Opening PD Comments at 11.

[147] *See* SCE Opening PD Comments at 9.

- How funds and administration of program will be split among the three IOUs,[148] consistent with the direction in this decision;
- Amount of administrative budget up to 10% of proportional share of the technology incentive budget each IOU will need to administer the program;
- A discussion of any balancing or memorandum account authorization sought to track program expenditures;
- Goal for number of customers reached, by when, and estimated MW demand savings;
- Identification of qualifying thermostats eligible for the $75 incentive;
- A process to ensure customers of both IOUs and third -party DRP programs are eligible for smart thermostat incentives;
- A description of the DR programs a customer must enroll in to be eligible for the thermostat incentive, and how that enrollment will occur before the customer receives a rebate;
- Implementation details including whether proof of purchase is needed for reimbursement, whether customers with existing eligible thermostats are eligible if not already enrolled in a DR program, number of thermostats per account, disqualification of customers with free thermostats;[149] and
- The process for identifying customers who qualify for ESA or CARE.

Income-eligible customers who are participating in the ESA program will continue to be eligible to receive no-cost, direct install smart thermostats through ESA for all climate zones. This eligibility is consistent with current policy

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[148] *See* PG&E Opening PD Comments at 7.

[149] *See* PG&E Opening PD Comments at 7 (advocating a sole thermostat per service account); SCE Opening PD Comments at 9; CEDMC Reply PD Comments at 5 (agreeing with PG&E on a sole thermostat per account).

detailed in the Statewide ESA Program Policy and Procedures Manual, as described in D.16-11-022 and reaffirmed in D.21-06-015. We carve out this group so that IOUs and third-party DRPs do not simply offer a $75 rebate to ESA or CARE-eligible customers who are eligible to have the whole cost of the smart thermostat subsidized, along with a package of other measures. Hence, if IOUs or third-party DRPs participate in the smart thermostat program adopted here, they must ensure that if the customer they are engaging is eligible for ESA or CARE, they are provided options, as described below.

The IOUs and third-party DRPs participating in the smart thermostat program adopted here will be required to verify customer eligibility for the ESA or CARE programs, and if eligible, provide the customer with information about the IOUs' ESA programs. Eligible customers may choose to obtain the smart thermostat through the ESA program or through the smart thermostat program adopted in this decision. If the customer receives the smart thermostat through the program described here, the customer must pre-enroll in a market integrated supply-side DR program. Such a customer may still participate in the ESA program for a potentially fuller suite of energy efficiency treatments at no cost. If the customer chooses to receive a smart thermostat through the ESA program, the IOUs and their ESA contractors, during their in-person assessment and installation, shall promote but not require enrollment in a market–integrated supply-side DR program.[150]

The Staff Concept Paper raised one point regarding Energy Efficiency and DR benefits of smart thermostats. In its testimony, PG&E responded to the Staff Concept Paper by proposing a change to a smart thermostat Energy

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[150] *See* Leapfrog Opening PD Comments at 6; CEDMC Opening PD Comments at 10; Google Opening PD Comments at 7.

Efficiency-DR integration program the Commission adopted in D.18-05-041.[151] PG&E requested leave for IOUs to propose changes to that program through an Advice Letter. The relevant program involves installation of smart thermostats and other distributed energy resource technology measures through the Commission's Energy Efficiency program, and captures DR benefits beyond energy savings. Decision 18-05-021 directed the IOUs to use $1 million for the residential sector and $20 million for the commercial sector from their "Integrated Demand-Side Management" program budgets to integrate delivery of Energy Efficiency and DR capabilities to customers. The guidance in D.18-05-041 also states that:

> The IOU [Energy Efficiency] PAs [Program Administrators] shall solicit, and other PAs should consider soliciting, third parties to design and implement programs to test various strategies and technologies for integrating [DR] capability with existing energy efficiency activities.[152]

PG&E refers to an Integrated Demand-Side Management Program Guidance document that PG&E did not attach to its testimony.[153] This document requests clarification on whether IOUs may conduct the foregoing integration activity themselves, without recourse to a third-party administrator. In reviewing D.18-05-041, however, it is clear that it allows IOUs to conduct the foregoing Energy Efficiency-DR integration activity without a third-party entity designing or implementing the program. IOUs must use the remaining budget and follow all other requirements outlined for limited integration programs

[151] D.18-05-041 at 36-38.

[152] *Id*. at 36.

[153] PG&E Opening Testimony at 7-9 & n.8.

described in D.18-05-041. The IOUs shall file a Tier 2 Advice Letter within 90 days of issuance of this decision[154] that should specify:

- Remaining budget from the originally authorized budget in D.18-05-041;
- How the remaining budget should be allocated among the IOUs to run their integration Energy Efficiency-DR programs; and
- Program implementation plans and design including information on how they comply with requirements outlined in D.18-05-041.

4.10. Dynamic Rate Pilots

We adopt two pilots that test how dynamic rates can cause customers to shift energy usage to off peak times, which can enhance system reliability in times of emergency. The first pilot, proposed by Valley Clean Energy (VCE), focuses on shifting agricultural water pumping to off peak times for reliability purposes through the use of dynamic rates and incentives. The second pilot, supported by SCE, uses TeMix's technology to facilitate the use of dynamic rates as an incentive to shift load for customers using electric vehicles, behind the meter energy storage, and similar flexible technologies.

4.10.1. Background on Dynamic Rate Pilots

Dynamic rates are time varying rates structured to provide incentives to customers to engage in energy consumption when demand is low, through rate differences. Time-varying rates include time of use rates and dynamic rates like critical peak pricing and real time pricing.[155] Time of use rates are set by time of day and are static throughout the season. Dynamic rates, on the other hand, can vary from day to day and hour to hour. For example, a real time pricing

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[154] *See* SCE Opening PD Comments at 11.

[155] *See* D.12-12-004 (uses "time of day" instead of "time of use.").

dynamic rate may pass the wholesale price of electricity directly to the retail customer as a portion of the commodity energy cost. Compared to other time-varying rates, a dynamic rate sends customers a much more granular and variable price signal about when to shift load.

Dynamic rates based on real time pricing may do the following under certain circumstances:

- Reduce grid infrastructure costs and greenhouse gas emissions.
- Improve reliability and integration of renewables.
- Facilitate greater integration and fair compensation of distributed energy resources.

Several jurisdictions currently offer real time pricing rates, including ComEd and Ameren in Illinois (for approximately 30,000 residential customers), Georgia Power (for approximately 2,000 non-residential customers), and Spain where a dynamic rate based on real time pricing is the default rate for approximately 10 million residential customers.

In California, real time pricing rates have occasionally been offered on a pilot or optional basis. For example, D.21-07-010 for SDG&E's GRC Phase 2 directed SDG&E to offer a pilot real time pricing rate that passes the wholesale price of electricity to retail customers as a portion of the commodity energy cost.[156] In addition, SDG&E's "Power Your Drive" rate for EV charging stations is a real time pricing rate with hourly commodity prices based on hourly CAISO day ahead energy market prices and hourly critical peak pricing-style pricing adders during hours of high system and circuit utilization to recover the cost of

[156] *See* D.21-07-010 at 47.

fixed generation and delivery (distribution) capacity in lieu of monthly demand charges.

The CEC's Electric Program Investment Charge (EPIC) grant number EPC-15-054 funded a transactive energy pilot in SCE's territory where the real time pricing rate included multiple dynamic rate components. The commodity rates were linked to the CAISO energy market price; dynamic capacity (generation and delivery) prices based on system/circuit utilization prices recovered the cost of fixed generation and delivery (distribution) capacity in lieu of monthly demand charges.

4.10.2. VCE Agricultural Pumping Dynamic Rate Pilot Proposal

VCE is a CCA in PG&E's territory and proposed to test the use of dynamic rates to provide incentives for large agricultural customers to pump water when it is least costly to do so. PG&E shall work with VCE under PG&E's DR Emerging Technologies program authorized in D.17-12-003 in administering and evaluating a dynamic transactive pilot rate for agricultural pumping loads in VCE's territory.

4.10.2.1. Background on VCE Agricultural Pumping Dynamic Rate Pilot Proposal

The Staff Concept Paper included VCE's proposal, which it also made in Phase 1 of this proceeding.

> **4. Agricultural Demand Flexibility Pilot**
>
> In Phase 1 of this proceeding, Valley Clean Energy (VCE), noting that it has annual irrigation pumping usage of ~100,000 MWh/year (15% of total service area load), submitted in its opening testimony a proposal for an Agricultural Demand Flexibility Pilot, supported by Sonoma Clean Power Authority, to be made available to customers on irrigation pumping tariffs. Staff offers as a proposal concept that a modified version of VCE's proposal be considered by

> the CPUC to tap into the load reduction/shift potential available in the pumping sector. VCE and other parties are encouraged to submit a more fleshed out proposal that includes the following elements:
>
> Incentivize automation of the pumping loads to receive an experimental rate that incorporates generation and delivery costs in hourly prices, with conventional monthly demand charges replaced by hourly, dynamic capacity charges. Design the experimental rate incorporating the ideas in the 6-step Distributed Energy Resource (DER) & Demand Flexibility roadmap described by ED Staff at the May 25, 2021, workshop on Advance DER and Demand Flexibility Management, specifically Steps 2 through 6. (Citation omitted.)
>
> Include a provision to hold PG&E harmless for any difference in cost recovery between the experimental rate's charges and the otherwise applicable tariff.
>
> Present the experimental rate to customers in a similar manner as the Step 1 of the above referenced 6-step roadmap.[157]

VCE responded with a proposal in its Opening Testimony. It explained that more than 85% of its service territory is designated for agricultural use, and that the agricultural sector represents approximately 18% of VCE's total annual load and 16% of its peak demand. VCE proposed a pilot for customers on irrigation pumping tariffs that will give the customers dynamic price signals using an experimental rate. Customers who successfully respond to the price signals and shift load out of expensive hours—typically the ramp hours—will enjoy bill savings.

[157] Staff Concept Paper at 12.

VCE proposes to enroll agricultural customers with aggregated peak load up to 5 MW in the pilot.[158] It seeks a three-year pilot program, running in 2022, 2023 and 2024. The pilot incorporates concepts from the DER & Demand Flexibility roadmap described in the Staff Concept Paper.[159] VCE plans to partner with TeMix and Polaris on the technology, which has already been tested through the CEC's ratepayer funded EPIC program.[160]

4.10.2.2. Party Comments on VCE Agricultural Pumping Dynamic Rate Pilot Proposal

Polaris, Joint DR Parties, TeMix and the California Farm Bureau Federation supported the pilot.[161] PG&E objected to the pilot, asserting the dynamic rate may not cover all fixed costs.[162] CLECA raised similar concerns for commercial customers.[163]

4.10.2.3. Adopted VCE Agricultural Pumping Dynamic Rate Pilot Direction

We approve VCE's pilot and direct PG&E to work with VCE on funding administration, tariff design and evaluation of the pilot. VCE shall have the principal role in carrying out the pilot, as described here.[164] The proposal is for a limited pilot project focused on the agricultural sector which has flexibility in

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[158] VCE Opening Testimony at 6; *see also* VCE Opening PD Comments at 3 (seeking clarification on reference to 5 MW).

[159] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

[160] CEC grants EPC-15-054 and EPC-16-054, respectively.

[161] Polaris Reply Testimony at 2; Joint DR Parties Opening Testimony at 27, Reply Testimony at 11-12; TeMix Opening Brief at 3-4; Farm Bureau Reply Brief at 3.

[162] PG&E Reply Testimony at 8-1 to 8-8.

[163] CLECA Opening Testimony at 7-8.

[164] *See* VCE/Polaris/TeMix Reply PD Comments at 1-3; PG&E Opening PD Comments at 8-9.

when it pumps water. Agriculture pumping has the capability to supply significant demand flexibility at low cost, since peak demand is 100% shiftable. The pilot has the potential to unlock up to 5 MW in the near term. The pilot has a simple, low-cost, program design with clear benefits matched to meet customer needs, and low administrative costs. Based on Polaris' submission, the estimated annual cost of the bill savings for customers on the pilot rate (without overhead costs) is $0.239/kWh for up to 800 MWh/year of load shift from peak to off peak periods.[165]

The pilot will provide valuable data about the potential of dynamic rates for load shift. The results from the program may help inform other load flexibility pilots and be used to scale dynamic rates to other customers. A dynamic hourly tariff provided day-ahead, with week-ahead projections, can be easily integrated with pump automation controllers. Automation will increase the responsiveness of the loads.

Non-generation and non-delivery costs (*e.g.*, transmission rates and non-bypassable charges) will be recovered through existing rate structures. The recommended "shadow bill" approach ensures that customers pay their default bills under the existing applicable tariffs. The pilot scale is limited to 5 MW of peak load, and therefore, the potential for any cost shift is contained.[166]

A volumetric rate for generation and delivery capacity cost recovery has been piloted in SCE territory through the CEC/EPIC funded Retail Automated Transactive Energy System (RATES) pilot project (EPC-15-054). The dynamic tariff in the RATES pilot was scaled to recover all authorized generation and

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[165] Polaris Reply Brief at 4.

[166] Polaris' Reply Brief at 4 extrapolates from its prior Transactive Energy Pilot that saving/incentives for the estimated load shift would be $192,720/year.

distribution revenues. Therefore, if pumping loads do not respond to dynamic prices and shift their usage, there is very limited potential for any under or over collection of revenues. If loads do respond to the dynamic prices, then the pilot will have achieved the intended purpose of shifting load to enhance system reliability. The VCE pilot provides an opportunity to assess the potential of a dynamic retail rate approach to incentivizing load shift.

The week ahead rate projections in the pilot will provide signals to agricultural customers on how to schedule pumping. Pumping is a significant portion of VCE's load, and therefore could deliver significant savings at peak. The pilot therefore provides an opportunity to examine a sector with significant load impact, and the results may be used to inform future rate design.

We adopt a "shadow bill" approach to address PG&E's and CLECA's objections about the revenue neutrality of the VCE pilot rate.[167] Customers will pay their PG&E bill based on existing tariffs, but the shadow bill will show the customer savings under the pilot dynamic rate, and VCE, and if necessary, PG&E,[168] will pay customers for the difference between the shadow bill and the existing tariff. PG&E's concerns over the need for billing systems upgrades and costs associated with those upgrades[169] are met by Joint DR parties' proposal[170] for this "shadow" billing solution.[171]

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[167] *See* VCE Opening Testimony at 7-9; Polaris Opening Brief at 6; Joint DR Parties Reply Testimony at 12.

[168] PG&E advocated flexibility on how to pay customers, and VCE supported resolving payment details in the Advice Letter. We support both suggestions. PG&E Opening PD Comments at 9-10; VCE Reply PD Comments at 4 n.2.

[169] PG&E Reply Testimony at 8-2.

[170] Joint DR Parties Reply Testimony at 12.

[171] TeMix Opening Brief at 10 points to SCE Advice Letter 3837-E for an example solution.

As for PG&E's assertion that it is not appropriate to use Auto DR or Public Purpose Program funds for enrolling/integrating loads into the pilot program,[172] we authorize new funding as specified in Attachment 1.

PG&E's objection that existing DR programs have not encouraged participation in the agricultural sector[173] supports trying a different approach as proposed in the VCE pilot. The pilot encourages action by providing prices and tools for agricultural customers to schedule usage ahead of time. Existing CEC/EPIC funded projects (EPC-16-045) have demonstrated success in incentivizing agricultural pumping load shift in response to dynamic prices provided ahead of time.[174]

PG&E's concern about the utilization of system/circuit load estimates for calculating the dynamic capacity recovery components of the pilot rate lacks merit, as there are existing Commission-approved retail rates, such as the SDG&E Power Your Drive Rate, where capacity costs are recovered through hourly pricing adders that are applied based on projections of high-usage system/circuit hours.

As described in Attachment 1 to this decision, the pilot will last for three years (2022-2024), and shall start no later than May 1, 2022. PG&E shall submit a midterm evaluation of the program no later than December 31, 2023, and a final evaluation no later than March 1, 2025, as described below. VCE, in consultation with PG&E, may engage a service provider with a suitable IT

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[172] PG&E Reply Testimony at 8-3.

[173] PG&E Reply Testimony at 8-4.

[174] Polaris Opening Testimony at 9.

platform to automate dynamic hourly prices and make them accessible to customers and automated agricultural water pumps.[175]

For the generation components of the service by VCE, (1) energy costs will be based on the CAISO wholesale market prices, and (2) generation capacity and flexible capacity costs will be recovered on an hourly basis using the scarcity pricing concept: more fixed costs are recovered when system utilization is higher relative to the system capacity limit.

For the delivery component of the service by PG&E, (1) line losses will be recovered through volumetric rates, which could be time dependent, and (2) distribution capacity costs will also be recovered on an hourly basis using the scarcity pricing concept in lieu of monthly or annual demand charges.

The capacity cost recovery functions (hourly price vs. system utilization) for all components (generation capacity, flexible capacity, and distribution capacity) will be calibrated to fully recover annual VCE generation costs and PG&E delivery costs. Other costs, including billing, metering, access, public purpose, and transmission costs may either be recovered through the existing rate structures or through a monthly subscription charge.

PG&E will credit any savings realized by the customers with respect to the delivery component of the pilot rate in the customers' shadow bills. PG&E shall set up a two-way balancing account to track expenses related to the delivery component of the customer bill savings during the pilot.

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[175] VCE requested clarification that it ultimately will select the IT provider, but VCE should consult with PG&E to ensure PG&E's system needs are addressed. VCE Opening PD Comments at 3-4.

PG&E, in coordination with VCE, is directed to contract with an independent evaluator to conduct a mid-term and final evaluation of this pilot.[176] The mid-term evaluation report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025. The evaluations should include the following elements:

1. The response of agricultural loads to prices, including the response to non-binding week ahead price projections. This should evaluate the efficacy of the pilot tariff in shifting agricultural loads enrolled in the program from peak to off-peak periods and should be compared to other VCE agricultural loads;
2. In the case that VCE incorporates binding forecast projections, the evaluation should also include an assessment of this element;
3. The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff;
4. An evaluation of the recovery of generation and RA costs for customers on the pilot tariff. This evaluation should assess the impact of any under collection of generation and RA revenues against the impact of the shifted participant loads on marginal generation and RA costs, and on the avoided cost value, including using the Commissions' Avoided Cost Calculator, where appropriate;[177] and
5. An evaluation of the recovery of delivery costs for customers on the pilot tariff. This evaluation should assess the impact of any under-collection of delivery revenues against the impact of the shifted participant loads on marginal delivery costs, and on the avoided cost value, including using the Commissions' Avoided Cost Calculator, where appropriate.

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[176] *See* PG&E Opening PD Comments at 8; VCE Opening PD Comments at 6.

[177] *See* Cal Advocates Opening PD Comments at 10; CLECA Reply PD Comments at 4-5.

PG&E is authorized a budget of up to $3.25 million for the administration and execution of the three-year pilot to be used in the manner specified in the table below.

Cost category	Budget
Integration and automation[178] of pumping loads with the pilot price signal	$1,000,000[179]
Vendor fees, Systems and Technology	$1,500,000[180]
PG&E Program Administration, including Billing and Evaluation[181]	$750,000

VCE shall be primarily responsible for the recruitment, integration, and automation of the pumping loads. PG&E shall coordinate with VCE to fund customer integration and automation expenses.[182]

VCE (in coordination with PG&E) shall submit a Tier 2 Advice Letter no later than 30 days after issuance of this decision[183] that includes the following

[178] For pump integration and automation, in lieu of Auto DR funds, customers, or the customers' pumping automation technology provider, may be funded up to $200 per kW of shiftable load as a one-time payment with a minimum three-year participation requirement, or for the duration of the pilot if it is extended up to a maximum of five years. To reduce any delays in implementation of the program, the funding may be provided on an aggregated basis to a pumping automation technology provider with multiple participating customers.

[179] *See* VCE Opening Testimony at 12 (proposing use of Auto DR funds for integration/automation of pumping loads). See also VCE Reply DR Comments at 3 (correctly seeking confirmation that the Proposed Decision did not intend for PG&E to be involved in integration and automation of pumping loads).

[180] *See* TeMix Opening Testimony at 3-4.

[181] See PG&E Opening PD Comments at 9 (seeking clarification that administration and evaluation budget is for PG&E).

[182] See PG&E Opening PD Comments at 8-9; VCE/Polaris/TeMix Opening PD Comments at 1-3.

[183] VCE supported reducing this period from 60 days as provided in the Proposed Decision to 30 days. VCE Reply PD Comments at 4. *See also* TeMix Reply PD Comments at 2.

elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, (5) pilot tariff design, and (6) details of how circuit and system data will be used to calibrate and calculate tariff price curves.[184]

PG&E (in coordination with VCE) is directed to submit a Tier 2 Advice Letter no later than 60 days[185] after issuance of this decision that includes, the following elements: (1) details of how circuit utilization data from the distribution circuits that serve VCE customers will be used to calibrate and calculate the delivery component of the dynamic prices, (2) details of how the circuit utilization data will be integrated with the pilot IT platform, and (3) the administration and evaluation budgets for this pilot.

4.10.3. SCE Dynamic Rate Pilot Proposal for All Customers and End Uses

We grant SCE authorization to use TeMix's RATES platform for a three-year (2022-2024) dynamic pricing pilot in SCE's territory, and grant SCE its requested $2.5 million for the pilot. The pilot is intended to assist in assessing the costs and benefits of real-time rates, including required infrastructure, manufacturer interest and customer impacts. SCE shall administer the pilot under its DR Emerging Markets and Technologies program authorized in D.17-12-003.

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[184] Cal Advocates requested that the Tier 1 Advice Letter in the Proposed Decision be a Tier 2 Advice Letter. Cal Advocates PD Comments at 10. *See also* TeMix Reply PD Comments at 2 and VCE Reply PD Comments at 4.

[185] PG&E requested a 90-day window, while TeMix and VCE requested 30 days, so we have adopted a mid-range. PG&E Opening PD Comments at 10; VCE Reply PD Comments at 4; TeMix Reply PD Comments at 2.

4.10.3.1. Background of SCE Dynamic Rate Pilot

SCE and TeMix propose a three-year dynamic rate pilot that uses a rate calculation platform developed by TeMix.[186] The pilot builds on the work done under a CEC-EPIC funded RATES pilot.[187] SCE seeks funding of $2.5 million for the pilot, which would run in 2022, 2023 and 2024. TeMix explains that its platform follows the "UNIDE" roadmap that Commission staff presented at the workshop cited in the staff concept proposal for this proceeding. TeMix explains that its UNIDE platform enables calculation of dynamic rates for flexible distributed energy resources such as electric vehicles and energy storage.[188]

4.10.3.2. Party Comments on the SCE Dynamic Rate Pilot

The Joint DR Parties support the pilot as a means of providing expedited access to dynamic pricing and customer billing of such rates.[189] They recommend making dynamic rates available to smart enabling technologies such as EV charging, behind the meter energy storage, and other controllable loads.[190] Polaris also supports use of the TeMix portal for dynamic rate pilots in other IOU territories.[191]

Stating that it is interested in exploring new pricing tariffs and enabling software that can facilitate local grid reliability and wholesale market

[186] TeMix Opening Testimony at 1-2; SCE Reply Testimony at 8-10.

[187] CEC grant EPC-15-054; available at https://www.energy.ca.gov/publications/2020/complete-and-low-cost-retail-automated-transactive-energy-system-rates.

[188] TeMix Opening Testimony at 2.

[189] Joint DR Parties Reply Testimony at 12, 24-26.

[190] Joint DR Parties Opening Testimony at 27.

[191] Polaris Reply Testimony at 2-3.

optimization, SCE supports use of the TeMix platform on a pilot basis, for "further demonstrations that can accelerate solutions for system reliability for 2022 and 2023."[192] SCE states the pilot "can provide a forum to explore options for both transactive price models and real time pricing with other parties and stakeholders, and demonstrate how new forms of distributed energy resources can act as both customer assets and grid interactive resources."[193]

There was no opposition to the pilot.

4.10.3.3. Adopted SCE Dynamic Rate Direction

We grant SCE authorization to conduct the pilot for the purpose of studying how price responsive pilot projects can enhance system reliability in 2022 and 2023.

As further set forth in Attachment 1, the pilot is open to SCE residential, commercial, and industrial customers, and SCE may prioritize customers with smart enabling price-responsive end-uses such as electric vehicle charging, behind-the-meter batteries, and controllable loads. The pilot is authorized for three years (2022-2024), starting no later than May 1, 2022.

To reduce the time required to integrate the pilot rate tariff with SCE's billing systems, SCE may use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot prices. In such an approach, participants will continue to pay their current SCE bill under the otherwise applicable tariff and will also receive a shadow pilot bill, which they will not pay, that illustrates a customer's potential savings

[192] SCE Reply Testimony at 8-9.

[193] *Id*. at 8.

under the pilot rate. Participants will receive payments from SCE for their pilot rate savings on either a monthly or annual basis.

SCE shall conduct a mid-term and final evaluation of the pilot to assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts. The mid-term report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025. The evaluations should include, but not be limited to, the following elements:

1. An evaluation of load responsiveness. SCE should evaluate the efficacy of the pilot tariff in shifting loads enrolled in the program from peak to off-peak periods and should be compared to non-participant loads;
2. The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff; and
3. An evaluation of the cost recovery which assess the impact of any under-collection of revenues associated with the pilot similar to the evaluation required of the VCE dynamic rate pilot.[194]

SCE shall submit a Tier 2 Advice Letter no later than 30 days after issuance of this decision that includes, but is not limited to, the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, and (5) pilot tariff design.[195]

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[194] *See* Cal Advocates Opening PD Comments at 12 (requesting parallel requirements to the VCE pilot).

[195] *See id.* at 10 (supporting change from Tier 1 to Tier 2). TeMix Reply PD Comments at 2 (requesting Tier 1); VCE Reply PD Comments at 4 (same).

5. Supply Side Resources

5.1. Summary of Procurement Ordered in this Decision

The purpose of this section is to summarize the characteristics and contracting requirements for procurement of the supply-side resources adopted in prior decisions and modified slightly as described in the subsections above. This decision applies the following requirements to the additional procurement ordered through this decision:

- Resources must available during both the peak and net peak demand periods.
- Commercial Online Dates (COD) (or contracts that are otherwise operationally consistent with the guidance in this decision) by June 1, 2022 are preferred but resources with CODs by August 1, 2023 will be considered. New resources that have not yet reached full capacity deliverability status but are capable of providing energy/grid reliability benefits during the peak and net peak periods will also be considered.
- Potential resources may include utility-owned storage, with Commission consideration of such projects through a Tier 2 Advice Letter.
- Resource types that may be considered for procurement include:
    - Incremental capacity from existing power plants through efficiency upgrades, revised power purchase agreements/tolling arrangements.
    - Contracting for generation that is at-risk of retirement.
    - Incremental energy storage, including utility-owned storage.
    - Acceleration of CODs from a resource that is otherwise required to meet an LSE's IRP target, *e.g.*, acceleration to June 1, for a resource that would otherwise be online by August 1.

- o Firm forward imported energy, as well as import contracts that ensure delivery during tight system conditions (*e.g.*, alerts, warnings, and emergencies or at contractually pre-specified prices) but the latter category can only be procured by IOUs and applied to the incremental reliability procurement targets adopted in this decision.
- Allow proposals for RA-only contracts or contracts that include dispatch rights or other means that stipulate how resources will bid into the energy markets.[196]
- Contracts of five years or more for efficiency improvements resulting in incremental generation at existing gas power plants require a Tier 3 Advice Letter.
- Incremental storage and preferred local resources procured by the Central Procurement Entity (CPE).

We also address some of the proposals made by parties or in the Staff Concept Paper. We allow the CPE to procure local capacity and allow bilateral contracting. We reject staff concept proposals to 1) increase or add penalties for delay or other failure of such procurement, 2) impose a non-bypassable charge (NBC) for emergency procurement ordered in this proceeding; and 3) change least cost dispatch (LCD) rules for hydroelectric generation.

In the following sections, we provide details on each of the foregoing supply-side requirements.

5.2. Additional Capacity Procurement and Use of Excess Resources to Meet Targets

PG&E, SCE and SDG&E shall continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for the

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[196] *See* PG&E Opening PD Comments at 15.

months of concern. These efforts should take the form of solicitations, ongoing bilateral negotiations, IOUs offering counterparties an opportunity to refresh prior IRP procurement bids, accelerated procurement of resources procured by LSEs to meet their IRP obligations for summer months prior to their required online dates, upgrades resulting in increased efficiency of existing generation resources, and imports. Consistent with resources ordered in Phase 1 in D.21-02-028 and D.21-03-056, the resources ordered here shall be available to serve load at peak and net peak.

Unless otherwise stated in this decision, IOUs shall submit all procurement contracts to the Commission via Tier 1 Advice Letters on a rolling basis. One exception is for contracts for incremental gas generation of five years or more and incremental imports. IOUs shall submit contracts of five years or more for efficiency improvements that result in incremental generation at existing gas power plants to the Commission in Tier 3 Advice Letters. Contracts for fossil-fuel development at new sites or for redevelopment or repowering at existing electric generation sites are not allowed and will not be considered.[197] Tier 1 Advice Letters are not required, but may be submitted, for incremental imports.

As noted previously, a combination of RA eligible and non-eligible resources will be used to meet the contingency procurement target range. All RA eligible resources supporting the effective PRM should be included in supply plans and IOUs' month ahead RA showings to ensure that these resources are subject to RA obligations and incentive mechanisms, do not receive CPM

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[197] *See* PG&E Opening PD Comments at 15. Since fossil-fuel resources are not currently allowable resources to meet the IRP Mid-term Reliability requirements, any fossil-fuel resources procured to meet the summer reliability targets established in this decision are not applicable to LSEs' IRP Mid-Term Reliability procurement requirements.

double-payments, and are visible to the CAISO as RA resources not eligible for export. Only costs associated with RA resources in excess of an IOU's own 15% PRM should be charged to all benefiting customers in the IOU's service territory via the Cost Allocation Mechanism (CAM).

To the extent feasible, IOUs shall pair imports contracted with maximum import capacity and include these costs in their CAM procurement costs. If existing IOU-owned maximum import capacity is paired with imports to construct an RA product, the IOU shall calculate and include the average price it received for sales of its excess maximum import capability (MIC) or, if not available or representative of market value, another reasonable market benchmark.

If an IOU has not met its minimum contingency procurement target for the months of June and October with RA eligible resources that can be reflected on supply plans, it may use excess resources in its existing portfolios to meet the minimum contingency procurement target (900 MW for PG&E and SCE, and 200 MW for SDG&E), provided it has made reasonable attempts to sell this excess capacity to other LSEs. In these instances, the excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

For the months of July, August, and September, excess resources from an IOU's existing portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target (1,350 MW for PG&E and SCE, and 300 MW for SDG&E), provided it has made reasonable attempts to sell this excess capacity to other. Again, these excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark. This approach ensures that the greatest amount of additional resources are procured during the three months of highest grid stress historically.

The benefit of showing these excess resources from IOUs' existing portfolios of resources is that they will be subject to RA requirements and incentive/penalty mechanisms, and they will be visible to CAISO as RA resources that are not available for export or a CPM payment. This approach also avoids the unintended outcome of IOUs buying excess RA resources from one another's RA solicitations to the extent each need to do so to meet their targeted additional procurement, potentially at premiums well in excess of the 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

The IOUs shall provide the monthly amounts of the excess resources they applied to the CAM, as well as the calculus used to determine these amounts to Energy Division, and Energy Division will post this information on its website.

Finally, to the extent that any additional adjustments to balancing accounts are needed to provide for CAM cost recovery of the procurement authorized in the decision, the IOUs may file Tier 2 Advice Letters with the effective date of the tariff modification to be the effective date of this decision.

5.3. Utility Owned and Third-Party Energy Storage

An Assigned Commissioner Ruling issued in this case on September 17, 2021, explained to all parties that this proceeding's Phase 1 decisions granted IOUs authority to procure for utility owned storage (UOS) to meet 2022 summer reliability needs. We address 2023 UOS in this decision.

5.3.1. Party Comments on Utility Owned and Third-Party Energy Storage

SDG&E requests that the Commission issue a second ruling as soon as possible applying the direction set forth in the ACR to utility-owned energy storage projects that can be online by summer of 2023. SDG&E also cites to several UOS projects that amount to over 200 MW that could be online late 2022 or early 2023.[198]

CESA agrees that the UOS projects identified by SDG&E represent promising potential for new incremental capacity to be added in support of near-term emergency reliability needs. CESA requests that the Commission require IOUs to procure third-party energy storage solutions in addition to UOS as long as it can be online to meet summer 2023 needs.[199] SDG&E agrees that the Commission should not prefer utility ownership of energy storage resources over third-party ownership, citing Governor Newsom's Emergency Proclamation's acknowledgement that potential reliability solutions include development of new resources by both IOUs and third parties through expedited processes.[200]

SCE notes that the ACR, D.21-02-028 and D.21-03-056 provide authority for SCE's UOS proposal. Under SCE's proposal, the UOS resources would first interconnect to non-CAISO controlled facilities and operate as a distribution

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[198] SDG&E Opening Testimony, DeTuri and Maiga at 3-11, McKay *passim*.

[199] CESA Opening Brief at 6-8. *See also* IEP Opening Testimony at 7 ("[t]here are no inherent advantages to utility ownership that should lead the Commission to prefer utility ownership of storage assets over independent ownership. Although constructing independently-owned equipment within a substation footprint may raise security and access concerns, the Commission should broaden consideration to other sites that share similar attributes with substations regarding site control, ease of interconnection, and deliverability.").

[200] SDG&E Reply Testimony, DeTuri and Maiga at 4-5.

asset. During this time, SCE would recover costs from all customers in its service territory through its distribution charge. Once the storage facilities are able to obtain interconnection to the CAISO's transmission system and CAISO's wholesale market, SCE will allocate the costs and benefits of the resource through the CAM. SCE requests that the Commission confirm this allocation approach in a Phase 2 decision.[201]

SCE also requests that the Commission confirm its understanding that the IOUs' authorization to pursue UOS for summer 2022 applies to UOS resources that may be operated by the IOUs as non-CAISO controlled grid assets, "fully within the jurisdiction of the Commission, that would not participate in the wholesale energy market or qualify for RA credit by summer 2022."[202]

SCE asks the Commission to allow UOS procurement in addition to IOU third-party procurement to meet summer 2022 procurement targets. Specifically, SCE recommends that the Commission set UOS targets and third-party targets based on the IOU's upper end targets in D.21-03-056. SCE also asks the Commission to find here that IOUs and LSEs may count any UOS projects toward their IRP mid-term reliability procurement requirements in D.21-06-035 based on their cost responsibility for such projects.[203]

PG&E recommends that the Commission continue the use of a Tier 2 AL process for utility-owned resources, with broad cost recovery through the existing CAM. PG&E also requests that the Commission indicate that utility-owned resources approved in this proceeding do not require a corresponding or subsequent application to be submitted to meet the

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[201] SCE Opening Testimony at 58-59.

[202] SCE Opening Brief at 49.

[203] *Id*. at 50.

procurement orders from D.21-06-035, the IRP decision that ordered 11,500 MW of new resources.[204]

5.3.2. Adopted UOS and Third-Party Storage Direction

We agree with SDG&E and CESA that incremental energy storage that can be brought online by summer 2022 or 2023 to meet the procurement targets, identified above, may be both UOS and third-party resources.[205] These storage resources need not be fully deliverable in 2022 or 2023, as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023. While we are allowing procurement of resources that are not fully deliverable that can be online during the emergency period, in this instance this allowance applies only to resources that are being brought online to meet the 2022 and 2023 summer reliability procurement authorized in this decision. In general, resources procured for IRP and RA purposes must be formally interconnected to the CAISO system and fully deliverable.[206]

We encourage siting these resources in locations where they will also provide benefits to local reliability and Disadvantaged Communities. We also confirm that SCE's proposed cost allocation for its UOS procurement would be an acceptable alternative to the CAM authority granted in D.21-02-028 when operating the resources as non-CAISO controlled grid assets prior to deliverability to CAISO markets.

Collecting the costs of this procurement through distribution rates until the resource is fully deliverable to CAISO markets is consistent with principles of

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[204] PG&E Opening Brief at 40.

[205] *See also* LS Power Opening PD Comments at 3; CESA Opening PD Comments at 4.

[206] *See* SEIA Opening PD Comments at 7; CalCCA Opening PD Comments at 6; CESA Opening PD Comments at 5-8.

CAM treatment. Distribution rates flow to all customers in an IOU's service territory, similar to CAM costs (which flow thorough a delivery charge to all benefiting customers). Additionally, resource costs should be tied to benefits and since distribution customers will receive the benefits of these resources, costs should follow this same allocation. Consistent with the principles of the CAM authority we granted in D.21-02-028, once the resource is connected to the transmission system and deliverable to CAISO markets, the costs shall no longer be collected through distribution rates, and instead the net capacity costs and benefits will be accounted for through the CAM mechanism.

In cases where UOS is operating as a distribution asset, the utility should take reasonable actions to minimize potential negative impacts on other projects by selecting sites that can accommodate the storage resources in addition to projects already in the interconnection queue. UOS projects will not be given any preferential treatment in the interconnection queue.

Given the urgency to get new resources online, we also agree with PG&E that the Tier 2 Advice Letter process and CAM for UOS should continue for 2022 and 2023. It is permissible for an IOU to use UOS resources procured for 2022 and/or 2023 summer reliability to meet its individual IRP Mid-term Reliability (MTR) requirements for its bundled customers after 2023 assuming the resource meets otherwise applicable IRP MTR resource requirements and the IOU charges only bundled customers for the post-2023 cost of the resources. The requirement established in D.21-06-035 obligating the IOUs to submit an application for utility-owned resources procured to meet IRP MTR resource requirements does not apply to UOS resources that are brought online in response to this order.

If an IOU elects to continue to charge all customers in its service territory for the ongoing costs of UOS resources after 2023, the resource will not count toward the IRP MTR requirements for the LSEs in the utility's service territory. IRP decision D.21-06-035 allowed LSEs to count toward their IRP procurement requirements eligible resources resulting from "procurement *that they have conducted* to support the Commission's orders or requirements … for emergency reliability purposes in R.20-11-003.[207] The decision did not prescribe the outcome for future resources or for resources being charged to all customers in an IOU's service territory via the CAM.

While these resources will not count toward existing IRP MTR procurement obligations, they will likely become part of the baseline used to calculate future reliability needs. In this way the resources will either reduce future IRP procurement requirements or otherwise lower the amount of procurement required. Beginning in 2024, any RA benefits associated with the resource will be allocated to benefiting customers for the period in which costs are shared.

If an IOU procures resources that are not fully deliverable, it shall work with the Commission's Energy Division and the CEC to ensure that benefits are allocated to all LSEs once the emergency procurement period has ended. During the emergency period, any associated load reduction will be applied toward the IOU's contingency procurement target.

5.4. Central Procurement Entity

This decision allows SCE and PG&E to negotiate bilateral contracts for the emergency procurement ordered in this decision in their capacities as CPEs.

5.4.1. Background on CPE

In D.20-06-002 in the RA proceeding, the Commission adopted a centralized framework for the procurement of local RA in the PG&E and SCE

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[207] D.21-06-035 at 80 (emphasis added).

distribution service areas, beginning with the 2023 RA compliance year. The decision identified PG&E and SCE as the CPEs for their respective distribution service areas, established an all-source solicitation process to procure existing and new resources, and required a Tier 3 Advice Letter process for contacts that exceeded five years in duration.

5.4.2. Party Comments on CPE

PG&E proposes in this proceeding that it be allowed bilateral contracting authority in its capacity as the CPE in addition to using the all-source solicitation process from D.20-06-002. PG&E asks to be allowed to bilaterally contract with counterparties that can both (1) provide incremental local RA resources in the CAISO-designated local areas of the procuring CPE's distribution service area and (2) meet the near-term emergency-based procurement requirements for the summers of 2022 and 2023 ordered in this decision.[208]

PG&E asks the Commission to allow the CPE to file a Tier 1 Advice Letter, consistent with D.21-02-028 and D.21-03-056, for expedited approval of bilateral contracts. PG&E requests that the costs of any incremental local RA resources be allocated similarly to other CAM resources procured by the CPE for local area reliability.[209]

Calpine supports PG&E's proposal, but notes that gas generation is cleaner than many of the alternatives that are being considered for emergency procurement. Calpine proposes that any procedure adopted for PG&E's proposal should apply to all resource types and not just preferred resources.[210]

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[208] PG&E Opening Brief at 37-38.

[209] *Id*. at 38.

[210] Calpine Opening Brief at 7.

CESA argues that it is unclear why PG&E needs to utilize its CPE function rather than its bundled procurement requirements to secure resources.[211]

5.4.3. Adopted CPE Direction

In its capacity as the CPE for local procurement, an IOU is best suited for the procurement of local resources through all-source solicitations to arrive at the least cost best fit set of options. However, given the near-term reliability needs to procure additional resources, the CPE is better suited to sign bilateral contracts for local procurement rather than an IOU's bundled procurement arm. This is because the CPE has been designated to meet local area requirements on behalf of all customers in the IOUs service area. For purposes of the procurement authorized in this decision, CPEs may make use of bilateral negotiations as well as all-source solicitations to procure local area resources. PG&E 's proposal to limit this procurement to storage and preferred resources will help to ensure that the CPE framework objectives are upheld, and we adopt it. Consistent with the direction in D.20-06-002 and procurement authorized in prior Advice Letter filings by PG&E, the CPE may procure dispatch rights, or other means that stipulate how local resources bid into the energy markets.[212] This modification allows for additional consideration of procurement types to meet system reliability in an expedited manner.

During the emergency period, resources procured by the CPE may count toward reducing the CPE's local procurement obligation. However, the system capacity benefit of these resources will not be allocated to all LSEs to reduce their

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[211] CESA Reply Testimony at 10.

[212] PG&E requested that the CPE be allowed to procure resources with "other means that stipulate how resources bid into the energy markets" as this is consistent with the direction in D.20-06-002 and procurement authorized in prior Advice Letter filings by PG&E to meet the procurement targets established in this proceeding. PG&E Opening PD Comments at 15.

system obligations. After the emergency period has ended, the system capacity benefit of these resources will be allocated to all benefiting LSEs consistent with other CPE procured resources.

The current list of eligible IOU procurement types (identified in section 5.1) does not limit local resource procurement. Further, we clarify that IOUs are not prohibited from procuring resources in local areas including incremental gas-fired capacity.

The CPE shall submit bilateral contracts executed pursuant to this authority as directed in the Phase 1 decision, D.21-02-028, and as summarized below.

5.5. Imports

We relax certain RA rules with regard to imports for IOUs only in order to help address summer reliability and potentially provide a wider pool of import products to procure for the summer months.

5.5.1. Background on Imports

In D.20-06-028, the Commission revised its rules for imports to count toward RA requirements. The Commission clarified its RA import rules to ensure that RA imports did not represent "speculative supply" that might not be available during stressed system conditions.

The new rules count non-resource-specific imports toward RA requirements, provided that:

(a) The contract is an energy contract with no economic curtailment provisions;

(b) The energy must self-schedule (or in the alternative, bid in at a level between negative \$150/MWh and \$0/MWh) into the CAISO day-ahead and real-time markets at least during the Availability Assessment Hours throughout the

RA compliance month, consistent with the MCC buckets; and

(c) The energy must be delivered to the load-serving entity in accordance with the governing contract, consistent with the MCC buckets.

5.5.2. Party Comments on Imports

CalCCA recommends two modifications to existing import RA requirements that would apply for imports procured to meet the summer 2022 and 2023 emergency procurement requirements adopted in this proceeding.[213] It recommends that we not apply the requirement to bid zero dollars or below for year 2022 and 2023 to these resources. It further asks the Commission to allow LSEs to meet emergency reliability procurement targets by contracting with imports after the RA showings deadline, up to the available unused MIC.

CalCCA's proposal would authorize LSEs to procure additional imports after RA showings, up to the amount of available MIC that was not used for monthly RA showings. CalCCA argues "that doing so would obviate the need for LSEs to procure additional MIC or take MIC from their own portfolio and then determine the value of that MIC, while still ensuring the imports procured are deliverable. By procuring imports after the month-ahead showing process, the amount of MIC not used for RA showings will be known, indicating a high probability that a firm energy import at that location would flow to the CAISO load."[214]

WPTF believes that imports procured for reliability purposes should be subject to RA import rules.[215] SCE proposes the Commission work with the

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[213] CalCCA Opening Testimony at 16.

[214] *Id*. at 17.

[215] WPTF Opening Testimony at 5.

CAISO to determine a process to upload monthly imports purchased after T-30,[216] on RA supply plans. The T-30 date is the CAISO's deadline to allow resources, procured by LSEs, to be designated as RA supply for California load. This action would allow these resources to be treated as RA for CAISO market mechanism purposes. SCE is already procuring non-RA imports after the T-30 window to help enhance system reliability under its existing D.21-03-056 authority. SCE suggests that monthly import products can be available in the market closer to the flow date, but after the RA compliance filing deadline. TURN supports SCE's proposal.[217]

5.5.3. Adopted Imports Direction

The August 2020 rotating outages and subsequent periods of stressed grid conditions in 2020 and 2021 involved high electricity demand and resource deficiencies that were not limited to the CAISO balancing authority area but were widespread across neighboring balancing authorities. These are the exact conditions in which unspecified imports become "speculative" and are at most risk of not performing. Importantly, the Day Ahead prices during the hours of concern for many of these periods did not reach the $1,000 price cap at which these unspecified imports regularly bid into the market, so few if any of these products would have been committed to deliver in the Day Ahead market, and under current CAISO market rules imports have no obligation to bid into the real time markets.

Consequently, had the new import rules not been in place this summer and had LSEs met their RA requirements with unspecified imports in place of other more reliable RA resources – especially resources that must offer into the

[216] T-30 means thirty days prior to the first day of the compliance month.

[217] TURN Reply Testimony at 7.

real time markets in addition to the Day Ahead market – the stressed grid conditions we experienced this summer would have been significantly more challenging.

In light of these concerns, relaxing the RA import rules could have the unintended consequence of adversely impacting reliability rather than improving it. Therefore, we do not adopt here CalCCA's proposal to relax import rules for all LSEs to meet their RA obligations. However, we do see merit in providing the IOUs maximum flexibility in procuring to achieve the targeted range of additional reliability resources authorized in this decision.

Consequently, we adopt CalCCA's recommendation that the import rules be relaxed, allowing import contracts that do not meet import requirements because they are executed after the month-ahead showing process in order to meet the effective PRM. This approach is justified because these contracts are structured to ensure delivery during tight conditions. We allow the IOUs to execute import contracts for the effective PRM that do not meet the RA import requirements but are structured to ensure delivery during tight system conditions (*e.g.*, CAISO Alerts, Warnings, and Emergencies or at contractually pre-specified prices).

We also see merit in SCE's proposal to allow late procured imports procured by IOUs to meet the effective PRM adopted here to be treated as RA under the CAISO's market mechanisms. Such action would enhance reliability by allowing these late procured imports to be treated as RA supply. Therefore, we direct Energy Division staff and the IOUs to work with CAISO to allow these resources to be shown as RA on supply plans.

5.6. Accelerate Procurement Already Ordered

Another staff concept put forward was to accelerate procurement already ordered in the Commission's IRP proceeding. We believe it may make sense to allow LSEs or project developers to bid into the IOUs' solicitations or contract bilaterally for accelerated procurement of 2022 resources. Accelerating 2024 IRP procurement into 2023 might be possible, but is already in scope for the IRP proceeding and should be considered there.

5.6.1. Background on Accelerated Procurement

Various decisions in the IRP proceeding have recently ordered additional procurement. The IRP Mid-Term Reliability decision, D.21-06-035, ordered an unprecedented 11,500 MW in new capacity for the 2023-2026 period, after D.19-11-016 in the same proceeding had ordered procurement of an initial 3,300 MW.

The Staff Concept Paper in this proceeding asked for party comment on whether accelerating some of the procurement ordered in both of these decisions might provide reliability at net peak for summer 2022 and 2023:

> All LSEs were ordered to procure new resources beginning in June 2023 in IRP decision D.21-06-035, the IRP's Mid-Term Reliability (MTR) Procurement Decision. To the extent that these 2023 resources could be brought online by summer 2022, the CPUC could provide an incentive to LSEs for early compliance with D.21-06-035.

Another staff concept was to give LSEs incentives to bring their IRP resources online early to ensure they are available for 2023.

5.6.2. Party Comments on Accelerated Procurement

The majority of parties providing testimony on whether to accelerate existing IRP obligations assert there is little ability for LSEs to accelerate procurement from 2023 into 2022 at this point in time. They assert they cannot move procurement due in August 2023 a full year earlier due to project development timelines. The testimony also noted that supply chains are especially tight at the moment, due to the impact of the COVID pandemic, making acceleration even less likely.

5.6.3. Adopted Accelerated Procurement Direction

We strongly encourage all LSEs – whether CPUC jurisdictional or not -- to take all steps possible to accelerate procurement to support increased grid reliability, but we decline to develop a new incentive regime for LSEs or generators to bring IRP procurement on earlier than expected. We agree with party comments that this could introduce gaming issues, which we wish to avoid. We also do not believe an entirely new incentive mechanism is necessary, since to the extent that IRP-ordered resources can be accelerated, generators and/or LSEs can and are encouraged to offer these resources into RFOs or bilaterally negotiate with the IOUs for incremental capacity that can be brought online in 2022 or 2023 in advance of the IRP required August deadlines. This effectively results in the same outcome, but allows for a market test of the price for accelerating these resources, since IOUs can compare offers of accelerating these projects with other resources being offered to meet their incremental procurement targets, rather than setting an arbitrary incentive amount and creating a new, likely complicated, reimbursement mechanism.

5.7. Introduce Penalties for Delays to D.19-11-016 Procurement

We do not introduce penalties for delays to the IOU and LSE procurement ordered in D.19-11-016. However, the Commission will closely monitor all ordered procurement and online dates to ensure deadlines are met.

5.7.1. Background of D.19-11-016 Penalty Issue

The Staff Concept Paper proposed instituting penalties related to procurement ordered in D.19-11-016, where no current penalties exist.[218] That decision, issued in the Commission's IRP proceeding, ordered system-level RA capacity of 3,300 MW by all LSEs serving load within the CAISO balancing authority area.

The Staff Concept Paper made the following suggestion:

> [The] CPUC could apply penalties to [LSEs] for not bringing ordered procurement resources online in accordance with [IRP] decision D.19-11-016. D.19-11-016 required Tranche 1 resources by August 1, 2021 and Tranche 2 resources by August 1, 2022, and Tranche 3 resources by August 1, 2023. There are no penalties imposed on LSEs for failure to meet online dates with new resources per D.19-11-016; however, as detailed in D.20-12-044, the CPUC intends to consider whether to order backstop procurement and allocate the cost of that backstop procurement to one or more LSEs.
>
> The CPUC could consider putting all LSEs on notice that it intends to impose fixed penalties (for instance, potentially $50,000 per incident) or capacity-based (potentially $10/kW by Month for each month delay) for any LSE that fails to achieve commercial online dates consistent with the order.

[218] A later decision in the IRP proceeding ordered an additional 11,500 MW of procurement to meet the CEC's Mid-Term Reliability predictions of need over the period 2023-2026. That decision imposes penalties related to delays or failures in procurement of the 11,500 MW ordered.

> The CPUC may consider a grace period of up to six months from the expected online dates. Although collectively, LSEs contracted for sufficient Tranche 1 resources, some Tranche 1 projects were delayed for a variety of reasons. Penalties (with or without a grace period) may ensure that the delayed Tranche 1 resources materialize prior to June 2022. Penalties (with or without a grace period) may ensure that Tranche 2 and 3 resources materialize with minimum delays in 2022 and 2023. Any procurement delayed Penalties would be incremental to any penalties associated with [RA] deficiencies, and LSEs would not be exempt from penalties even if they were otherwise fully resourced for [RA].

5.7.2. Party Positions on D.19-11-016 Penalties

Most parties commenting on whether to impose penalties for delays or failures in D.19-11-016 procurement oppose the proposal.[219] They assert penalties will not spur speedy procurement at this time, since close to 100% of D.19-11-016 contracts have already been executed. They state LSEs are adequately incentivized to bring delayed procurement online via the backstop procurement mechanism.[220]

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[219] Comments opposing penalties appear in the CALCCA Opening Testimony at 8; Calpine Opening Testimony at 2; IEP Opening Testimony at 3; CESA Opening Testimony at 11; LS Power Opening Testimony at 7; SEIA Opening Testimony at 12; SCE Opening Testimony at 76; SDG&E Opening Testimony, DeTuri and Maiga at 6; PG&E Opening Testimony at 9-1; WPTF Opening Testimony at 2; and CASMU Opening Testimony at 6.

[220] SCE Opening Testimony at 77 ("SCE recommends the Commission maintain the process in D.20-12-044 for LSEs to submit biennial compliance filings and apply the trigger mechanism for IOUs to backstop an LSE that fails to meet milestone requirement.").

As described in D.20-12-044 at 4:

> The backstop procurement mechanism contemplated by D.19-11-016 assumed that backstop procurement would be needed when LSEs that planned to self-provide their required capacity were unable to do so for a variety of reasons. D.19-11-016 determined that if this happens, the Commission may order the relevant investor-owned utility (IOU) to conduct procurement on behalf of the LSE that has failed to procure its allocated share of capacity and/or on behalf of its customers.

Cal Advocates supports penalties targeted to getting delayed summer 2021 procurement online by June 1, 2022.[221]

5.7.3. Discussion of D.19-11-016 Penalties

We decline to impose penalties related to D.19-11-016. Given that contracts for that procurement are already executed, penalties will not hasten contracting. However, Commission staff will be very involved in ensuring that all remaining procurement of the 3,300 MW ordered in D.19-11-016 is on a path to timely online status, and will intervene if delays become apparent. Energy Division will be in ongoing contact with all affected LSEs to ensure procurement and online dates are on track for summer 2022.

5.8. Increase RA Penalties

We also decline to increase penalties already adopted for failures in RA procurement.

5.8.1. Background on RA Penalties

Decision 21-06-029 adopted a tiered RA penalty structure to be implemented in 2022. RA penalties will double or triple for LSEs with recurring deficiencies. However, since the structure has not yet been implemented, all LSEs will likely be in Tier 1 for much of 2022.

The Staff Concept Paper asked parties to comment on whether the Commission should increase penalties related to RA in order to ensure all obligations are in place on time. Staff's proposal was as follows:

> Pursuant to D.20-06-031, the RA penalty structure is currently $8.88 kW/month for LSEs who fail to meet summer system RA obligations in the month ahead. The CPUC could consider doubling the penalties for LSEs who may be short in August 2022 and September 2022.

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[221] Cal Advocates Opening Testimony at 21.

5.8.2. Party Comments on RA Penalties

Most parties opposed additional penalties for failures in procurement.[222] Many parties considered it premature to revise the RA penalty structure at this time given that the tiered structure was recently adopted and will not be implemented until 2022.[223] Some parties supported consideration of increased penalties for the summer of 2022 given that there would be a delay between implementation of the tiered penalty structure and accrual of sufficient points by deficient LSEs to move them into higher penalty tiers.[224]

5.8.3. Discussion of RA Penalties

We agree with parties that the impacts of the recent changes to the RA penalty structure should be assessed before additional changes are made. We thus decline to increase the penalties for deficiencies in meeting RA obligations beyond those already adopted.

5.9. Once Through Cooling (OTC) Units

We eliminate the Tier 3 Advice Letter filing requirement for approval of IOU contracts with OTC units.

5.9.1. Background on OTC Units

The IOUs are currently authorized to contract with OTC units, including in anticipation of extension of their compliance deadlines. Existing Commission

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[222] CalCCA Reply Testimony at 9; PG&E Opening Testimony at 9-2; Cal Advocates Opening Testimony at 3-2; SCE Opening Testimony at 78; WPTF Opening Testimony at 4; SEIA Opening Testimony at 11-15; MRP Opening Testimony at 20; CESA Opening Testimony at 14; LS Power Opening Testimony at 3.

[223] CalCCA Opening Testimony at 9-10; PG&E Opening Testimony at 9-3 – 9-4; Cal Advocates Opening Testimony at 3-2 – 3-3; SCE Opening Testimony at 78; WPTF Opening Testimony at 4; CESA Opening Testimony at 14; MRP Opening Testimony at 20; TURN Reply Testimony at 8; LS Power Opening Testimony at 7.

[224] Calpine Opening Testimony at 3.

decisions require that the IOU seek approval of the OTC contracts via a Tier 3 Advice Letter.[225]

5.9.2. Party Comments on OTC Units

SCE asks that the Commission eliminate the Tier 3 Advice Letter requirement for OTC units needed for emergency reliability adopted in D.21-02-028. SCE states the time needed to obtain Tier 3 Advice Letter approval impedes timely contracting. SCE argues that the requirement places the IOUs at a competitive disadvantage against non-IOU buyers that do not require Commission approval. SCE requests that the Commission authorize the IOUs to contract with OTC units through 2023 under their Bundled Procurement Plan authority without the requirement to file a Tier 3 Advice Letter."[226]

5.9.3. Adopted OTC Direction

Given that no other LSE has to file for approval of contracts with OTCs, we approve SCE's request. The Tier 3 Advice Letter requirement is eliminated for contracts with OTC units that are needed to meet any reliability needs, including RA compliance requirements. This result will put the IOUs on a level playing field with the non-IOUs, and help the IOUs to meet their RA obligations.[227] Ultimately, the extension of the OTC units is predicated on the expiration date of their Water Board permit, not the contracting process (nor the regulatory approval process of any contracts) that these units hold with counterparties.

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[225] D.19-11-016 at 48.

[226] SCE Opening Brief at 56.

[227] The IOUs are procuring both for their own bundled customers (up to a 15% PRM) and for the "incremental PRM" ordered in this decision. They are free to use the OTC to fill either bucket (incremental PRM or to meet the 15% for their bundled customers). This puts them on a level playing field with other LSEs, who are not required to obtain Commission approval to sign contracts with OTCs. *See* SCE Opening PD Comments at 12.

5.9.4. Cost Background on Cost Allocation Mechanism

5.10. D.21-02-028 and Allocation Mechanism

D.21-03-056 allowed the IOUs to procure resources for all customers in their service territory for emergency reliability purposes and recover costs for those resources through a CAM.[228] The Staff Concept Paper asked whether this authority should be broadened for 2022 and 2023.

5.10.1. Party Comments on Cost Allocation Mechanism

CalCCA argues that if the Commission adopts a procurement mechanism in which the IOUs procure on behalf of all benefitting customers, the Commission should clarify the method for allocating costs and benefits. Specifically, CalCCA suggests that if an IOU contract under D.21-03-056 extends beyond 2022, the costs and benefits should either be allocated solely to bundled service customers, not through the CAM, or that all customers should be allocated both the costs and the benefits.

SCE notes that neither IOUs nor other LSEs receive RA benefits for D.21-03-056 "effective" PRM procurement, and for that reason opposes CalCCA's proposal.

SCE agrees with CalCCA that it would be helpful for the Commission to clarify the treatment of RA benefits after the period of the emergency ends. SCE supports allocation of any RA benefits associated with D.21-03-056 procurement to all benefitting customers for the remaining term of the contracts (or utility-owned resource) after the emergency period.

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[228] D.21-02-028 at 12.

5.10.2. Adopted Cost Allocation Mechanism Direction

We do not change the CAM authority granted in D.21-02-028 and D.21-03-056, and extend that decision's allowance to summer 2023 procurement ordered in this decision. If an IOU needs to use the procurement to meet its bundled service RA requirements, then the costs are not recovered through CAM, but rather from bundled service customers. In D.21-03-056, the Commission recognized that some contracts may not be tailored to the months of most concern and may require year-round obligations, so we make clear here that while IOUs should strive to layer resources to meet the most critical months, the net costs associated with this incremental procurement shall be shared by all customers in each IOU's service territory, since all customers share the additional reliability benefits.

Emergency reliability procurement benefits all customers, whether bundled IOU customers or customers of other LSEs. The CAM appropriately places cost requirement responsibility with all customers for emergency procurement ordered in D.21-03-056. Therefore, we make no change to that decision's CAM authority, except that we extend this authority to emergency procurement authorized in this decision.

After the emergency procurement period, during which IOUs procure incremental reliability resources on behalf of all customers, ends, the RA benefits of any resources whose contracts extend beyond the emergency procurement period shall be allocated consistent with their approved cost recovery mechanism.

5.11. NBC for Emergency-Based Procurement

We decline to adopt the staff concept proposal for an NBC for emergency-procurement ordered in this decision.

5.11.1. Background on NBC

The staff concept proposal on an NBC for emergency reliability procurement was detailed, as follows:

> **Emergency Procurement and Cost Recovery via a Non-Bypassable Charge**
>
> The CPUC could establish a new non-bypassable charge (NBC) for cost recovery of costs associated with emergency procurement that adds additional reserve margin and does not already fit into an existing cost recovery mechanism.
>
> Although there is an existing [CAM] charge frequently used for IOU cost recovery associated with eligible capacity costs, the CAM charge does not usually allow for cost recovery for emergency procurement that adds to reserve margins or for resources that do not provide firm [RA].

The staff went on to list "emergency" procurement options, and we adopt some of those in other portions of this decision, but we reject the idea of an NBC itself. Instead, the procurement options we adopt will be subject to the CAM process described in this decision.

5.11.2. Party Comments on NBC

SDG&E supported an NBC. PG&E and SCE opposed it on the ground the existing CAM charge authorized in Phase 1 of this proceeding is adequate for cost recovery.[229]

5.11.3. Discussion of NBC

We are not convinced there is a need for a new NBC given that the Commission has already authorized use of a CAM mechanism to allocate procurement costs to all LSEs in Phase 1 of this proceeding and in this decision. The main benefit of an NBC would be that non-IOU procurement could be

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[229] SDG&E Opening Testimony, DeTuri and Maiga at 4; SCE Opening Testimony at 79-80; PG&E Opening Testimony at 9-4 – 9-5.

eligible. However, this would be complicated since standards are unclear for contract approval and reasonableness review of non-IOU contracts.

5.12. Change LCD for Hydroelectric Generation

We reject staff's proposed LCD for hydroelectric generation change on the ground that it is not necessary for reliability.

5.12.1. Background of LCD for Hydroelectric Generation

The Staff Concept Paper for hydroelectric resources suggested that IOUs be permitted to hold hydroelectric generation in reserve for the most grid-stressed conditions:

> **Bundled Procurement Rules Modifications**
>
> Under existing bundled procurement rules, the IOUs are required to schedule and bid their hydro resources to achieve least cost procurement. The CPUC could adjust these rules to allow IOUs to preserve hydro generation for maximum availability during strained grid conditions, instead of using hydro at all times when it appears to be economically efficient. This policy change would effectively allow IOUs to plan for hydro resources to count for a higher RA value in August and September, during hours when it is most critically needed.

5.12.2. Party Comments on LCD for Hydroelectric Generation

Most parties argued that additional flexibility to bid hydroelectric generation into the market were not warranted.[230] PG&E and SCE both oppose the staff proposal to allow use of hydroelectric generation where reliability concerns are greatest.[231] PG&E states it already manages hydroelectric generation to maximize its availability during reliability events:

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[230] PG&E Opening Testimony at 9-5; SCE Opening Testimony at 80; MRP Opening Testimony at 26; TURN Reply Testimony at 8.

[231] PG&E Opening Testimony 9-5 – 9-6, SCE Opening Testimony at 80.

> Modifications would not result in additional capacity being available for critical peak events nor additional RA value available in August and September as suggested.
>
> PG&E optimizes the dispatch of its hydroelectric fleet on a forecast basis to maximize customer benefit, which includes the ability to generate during critical reliability events. Throughout the year and for each of PG&E's watersheds, water plans are updated weekly, using the latest forecasts of water supply and energy demand as well as safety, physical, operational, and license constraints.

SCE also asserts adjustment to the hydro generation rules is unnecessary:

> Least cost dispatch principles . . . ensure[] that resources are awarded when they are needed the most (*i.e.*, when market prices are highest, or system conditions are strained). Thus, there is no need to adjust bundled procurement rules.

When considering the trade-off between generating in earlier months of the year versus August and September, PG&E's processes already incorporate maximizing generation for the later summer period. While PG&E uses price forwards to indicate when energy is most needed, there is a correlation between prices and high need periods. Additionally, PG&E's operators consider summer reliability needs and August and September RA needs when making dispatch decisions throughout the year. PG&E does not believe that changing the regulatory framework for hydroelectric bidding decisions will result in any incremental benefits given that actual dispatch decisions generally would not change.

Regardless of the RA value (measured in terms of a net qualifying capacity), PG&E makes its dispatchable hydroelectric capacity available during critical reliability events. PG&E does not believe that the capacity that would be available next year during similar critical events would be any less than this year, and it could be greater, if the drought diminishes. Additionally, PG&E does not believe this capacity would be any greater if the LCD rules were changed as proposed in the Concept Paper. Accordingly, PG&E does not believe modifications to the current LCD practices are warranted for its hydroelectric resources and opposes this proposal from the Concept Paper.

5.12.3. Adopted LCD Direction

We find that there is no need to change the LCD rules for hydroelectric generation.

6. Process for Commission Review of Allowed Procurement

The process for Commission review of additional, incremental procurement ordered in this decision is similar to the process we adopted in D.21-02-028 and D.21-03-056. The large electric IOUs shall submit contracts that conform with this decision for consideration as Advice Letters. As noted in various places, most contracts are appropriate for Tier 1 Advice Letters; utilities shall submit contracts for utility-owned storage as Tier 2 Advice Letters. Contracts of five years or more for incremental generation at existing gas power plants shall be submitted to the Commission via a Tier 3 Advice Letter. Along with the contracts, the Advice Letter submittals shall include the following additional summarized information to assist with evaluation. As stated above, Tier 1 Advice Letters are not required but may be submitted for incremental imports. A summary of the resources being selected and a brief discussion of the procurement and selection method and criteria;

- Operational information of the resources contracted and a demonstration that the resource will be available during the peak and net peak demand hours in summer 2022 and/or summer 2023;[232]

- Pricing and net market value analysis along with a summary of the key contract terms;
- A completed analysis by the independent evaluator;
- To the extent comparable data exists, a demonstration of cost competitiveness, recognizing that premiums for expedited procurement must be considered in any such demonstration;
- A demonstration that the resource is incremental (except for contracts with resources falling of contract and at risk of retirement); and
- A demonstration that the resource has a path to deliver its online date in summer 2022 or 2023.

To assist the Commission with evaluation, pursuant to Section 7.3.1 of General Order 96-B, Tier 1 Advice Letters that are submitted to the Commission that result from this decision are effective no sooner than five days after submission. Solely for purposes of supply-side procurement ordered in this decision, we shorten the protest period for those Tier 1 Advice Letters to 10 calendar days after submission. Additionally, the large electric IOUs are authorized to file Tier 2 Advice Letters for utility-owned storage with a COD by summer 2022 or 2023. These IOUs may also file Tier 2 Advice Letters making

[232] Consistent with current reliability resource requirements, 4-hour storage resources are considered acceptable resources to meet the peak and net peak needs, though they may not be available throughout the entire peak and net peak period. D.14-06-050 (Appendix B) adopted a qualifying capacity (QC) methodology for energy storage resources that states:

> Dispatchable storage shall receive a QC in the same manner as other dispatchable resources, including testing and verification in CAISO operations. Because all RA resources must be able to operate for four or more consecutive hours, the storage operator must submit to the CAISO an output level (in MW) at which the resource is capable of discharging for four or more uninterrupted hours; this is defined to be its PmaxRA, the maximum output that can be considered for RA calculations.

any tariff changes needed to adjust balancing accounts to implement this decision.

Consistent with D.21-03-056, after hydroelectric resource conditions are better understood and to better prepare for any additional measures to meet summer peak load in the event of another extreme weather event, all LSEs are required to provide Energy Division non-binding month-ahead RA filings for July, August and September 2022 and 2023. The filings are due no later than April 15, 2022 (for 2022) and April 15, 2023 (for 2023) reflecting the LSE's most recent RA positions, including any excess RA procurement (but excluding the IOUs' "effective PRM" procurement authorized in this proceeding).

7. Conclusion

The Commission must act now to ensure there are adequate resources available to provide reliable electricity to Californians in summers of 2022 and 2023 in the occurrence of extreme weather events. With the combination of supply- and demand- side resources ordered here, the Commission attempts to help better position the State to meet Californians' electricity need at net peak – after the sun goes down each day and solar energy stops producing – in summer 2022 and 2023 during extreme weather events. If additional changes are needed as summer 2022 approaches, the Commission will take further steps as necessary to help maintain reliability.

8. Comments on Proposed Decision and Administrative Matters

The proposed decision of ALJ Thomas 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. The comment period was shortened pursuant to Commission Rule of Practice and Procedure 14.6(c)(10) on the ground of public necessity, such that opening comments were due on November 10, 2021 and reply comments were due on November 16, 2021. Opening comments were filed on November 10, 2021 by American Clean Power-California, Advanced Energy Economy, Alliance for Retail Energy Markets, Broad Reach Power LLC, California Independent System Operator Corporation, California Community Choice Association, Calpine Corporation, California Solar & Storage Association, California Biomass Energy Alliance, Center for Energy Efficiency and Renewable Technologies, California Energy + Demand Management Council, California Environmental Justice Alliance & Sierra Club, California Energy Storage Alliance, California Large Energy Consumers Association, Google LLC, Green Power Institute, Independent Energy Producers Association, Joint Demand Response Parties, Joint CCA Parties, Leapfrog Power, Inc., LS Power Development, LLC, Middle River Power LLC, OhmConnect, Inc., Protect Our Communities Foundation, Pacific Gas and Electric Company, Polaris, TeMix/ VCE, Public Advocates Office, Small Business Utility Advocates, Southern California Edison Company, San Diego Gas & Electric Company, Solar Energy Industries Association and Large-Scale Solar Association, Sunrun, Inc., TeMix, Inc., Tesla, The Utility Reform Network, and Vehicle Grid Integration Council. Reply comments were filed on November 16, 2021 by American Clean Power- California, Advanced Energy Economy, California Community Choice Association, California Solar & Storage Association, Center for Energy Efficiency and Renewable Technologies, California Environmental Justice Alliance & Sierra Club, California Large Energy Consumers Association, Google LLC, Independent Energy Producers Association, Leapfrog Power, Inc., Middle River Power LLC, Protect Our Communities Foundation, Pacific Gas and Electric Company, Polaris/ TeMix/ VCE, Southern California Edison Company, San Diego Gas & Electric Company, Solar Energy Industries Association and Large-Scale Solar Association, TeMix, Inc., The Utility Reform Network, Vehicle Grid Integration Council, Enchanted Rock LLC, and Fermata Energy. Numerous non-substantive changes were made throughout the document to clarify the proposed decision and respond to comments. Additionally, numerous substantive modifications were made, all in response to comments and reply comments on the proposed decision, as outlined below in this section.

- We provide additional detail on the need for additional resources in 2023.
- We modify elements of the ELRP program eligibility criterion regarding customer participation in dynamic rates and modify elements of the technical requirements for compensation for virtual power plant aggregators.
- We clarify that for Residential ELRP, IOUs are to automatically enroll CARE and FERA customers (which are a good proxy for ESA customers); note that such customers are eligible to exit the program at any time; and allow the IOUs discretion in which baseline they use to count load reductions and calculate payments to customers, with a joint evaluation of the baseline due no later than January 15, 2023.
- We eliminate the direction regarding BUGs dispatch sequence. We replace that language with direction regarding the disallowance of BUGs as an ELRP resource for non-residential participants in Disadvantaged Communities.
- We expand the Flex Alert paid media campaign to cover the ELRP Residential program triggers (CAISO Flex Alerts and category “A” CAISO grid alerts from CAISO’s Alert, Warning, Emergency alert system) and discouraging the use of BUGs using prohibited resources for Residential ELRP.

- We omit the provision in the Proposed Decision that Residential ELRP customers or ELRP group A.4 and A.5 may not simultaneously be enrolled in a critical peak pricing, SmartRate or similar dynamic rate tariff and enroll in the ELRP pilot, since IOUs do not have visibility into whether customers are taking service under critical peak pricing, SmartRate or similar dynamic rate tariffs. Since IOUs have visibility into whether customers are receiving service pursuant to a CAISO integrated, or "supply side" DR program, we retain the dual participation bar for such programs and Residential ELRP and ELRP groups A.4 and A.5.
- We modify elements of the DR Program modifications instituted in the proposed decision. These changes are regarding DR program eligibility, baseline adjustments allowed for CBP and DRAM, and an authorization for SCE to recover costs that occur in the Smart Energy Program due to the "hot climate zone" thermostat incentive program adopted in this decision.
- We remove the modification to Commission Resolution E-4906 that was initiated in the proposed decision.
- We clarify that ESA and CARE customers may elect the "hot climate zone" smart thermostat adopted in this decision (which pays $75 for the smart thermostat and requires DR enrollment) or receive the full smart thermostat subsidy and avoid the mandatory DR enrollment by participating in the ESA smart thermostat program.
- We clarify that VCE should have primary responsibility to run the VCE dynamic rates pilot, with input and support from PG&E, and set forth the evaluation criteria for the SCE dynamic rates pilot.
- We make several clarifying changes to the supply side portion of the decision, to:
  - Explain that CODs (or contracts that are otherwise operationally consistent with the guidance in this

decision) by June 1, 2022 are preferred but resources with CODs by August 1, 2023 will be considered;

- o Explain that new resources that have not yet reached full capacity deliverability status but are capable of providing energy/grid reliability benefits during the peak and net peak periods will also be considered;
- o Explain how emergency reliability resources procured to meet the requirements of this decision, may count toward existing IRP requirements. If the IOU elects to recover the costs of the emergency resources from all customers in its service territory during and beyond the emergency procurement period, then these resources will not count toward IRP requirements. If the IOU elects to recover the costs of the emergency resources from their bundled customers after the emergency procurement period, then the resource may count toward its IRP requirements.
- o Clarify that UOS allowed in this decision does not displace existing resources in the interconnection queue;
- o Clarify that if an IOU procures resources that are not fully deliverable, it shall work with the Commission's Energy Division and the CEC to ensure that benefits are allocated to all LSEs once the emergency procurement period has ended;
- o State that the requirement established in D.21-06-035 obligating the IOUs to submit an application for utility-owned resources procured to meet IRP MTR resource requirements does not apply to UOS resources that are brought online in response to this order;
- o State that during the emergency period, resources procured by the CPE may count toward reducing the CPE's local procurement obligation. However, the system capacity benefit of these resources will not be allocated to all LSEs to reduce their system obligations. After the emergency period has ended, the system capacity benefit of these resources will be allocated to

all benefiting LSEs consistent with other CPE procured resources; and

- o Clarify that the list of eligible procurement may include contracts that include dispatch rights, or other means that stipulate how resources bid into the energy markets.
- o Eliminate the requirement of a Tier 3 Advice Letter for OTC plants needed to meet any reliability needs, including RA compliance requirements, putting IOUs on a level playing field with other LSEs, which are not required to obtain Commission approval to sign contracts with OTC.

The Commission affirms the rulings made by the assigned Administrative Law Judges and denies all motions not ruled upon as moot.

9. Assignment of Proceeding

Marybel Batjer is the assigned Commissioner and Sarah R. Thomas and Brian Stevens are the assigned ALJs in this proceeding.

Findings of Fact

1. On July 30, 2021, Governor Newsom issued an Emergency Proclamation calling on the Commission, among other State agencies, to require additional electric resources be available in summer 2022 on an expedited basis due to extreme heat events, prolonged drought, decreased hydroelectric generation, catastrophic wildfires and climate change.

2. In August 2020, a majority of the western United States encountered a prolonged extreme heat event.

3. As a result of the prolonged heat event, the CAISO initiated rotating outages in its balancing authority area to prevent wide-spread service interruptions.

4. On October 6, 2020, the CPUC, California Energy Commission, and CAISO published a Preliminary Root Cause Analysis report that examined the cause of the August 2020 rotating outages.

5. The 2020 Preliminary Root Cause Analysis identified several actions that will address the contributing factors that caused the August 2020 rotating outages. The actions identified in the Preliminary Root Cause Analysis include expediting the regulatory and procurement processes to develop additional resources that can be online by summer 2021.

6. There is a need for incremental physical resources and modified DR measures to address grid needs during the system peak and net peak demand periods for summer 2022 and 2023 and to prevent similar service interruptions to the August 2020 rotating outages.

7. Time is of the essence, and the Commission needs to expeditiously signal support of contracts for expansion of existing resources that can help maintain reliability in summer 2022 and 2023 by delivering during peak and net peak demand periods.

8. There is a need for new supply- and demand-side resources to serve as continency resources at net peak in summer 2022 and 2023.

9. The Commission has data and policy expertise that allow it to assess the need for additional contingency resources at net peak in summer 2022 and 2023.

10. If an extreme weather event were to occur, there is a need for contingency resources in the summers of 2022-2023 in the range of 2,000 MW to 3,000 MW.

11. The 2,000-3,000 MW range provides for the procurement of contingency resources to meet an effective PRM of between 20% and 22.5% to ensure reliable electric supply during extreme circumstances. Additional resources that meet

this higher effective PRM will provide additional reliability in the event of a need for contingencies above the existing PRM during extreme events.

12. Since the summer 2020 rolling outages and Joint Agency Root Cause Analysis, the Commission has ordered additional procurement in multiple venues.

13. Current planning and procurement resource levels may not be sufficient through 2023 under extreme conditions. Concerns regarding resource availability at net peak may persist from 2022 into 2023.

14. LSEs may struggle to meet their existing 2022 and 2023 procurement targets given supply chain disruptions and other factors.

15. A risk of extreme weather may continue through 2023, including the risk that persistent drought conditions will diminish hydroelectricity supply. Even if these risks do not materialize, a portion of the supply will be called upon and paid for only when there is a triggering event, reducing the cost associated with the procurement of contingency resources.

16. A conservative approach to emergency reliability now could help avoid further just-in-time procurement in the future.

17. Numerous extreme conditions and supply risks may be mitigated by continuation and expansion of contingency procurement in 2022 and 2023. The conditions include heightened risks associated with climate change, extreme heatwaves, dry hydro conditions, potential West-wide capacity shortages, supply chain issues with procurement underway, and project contract failures, among a host of other planning uncertainties.

18. In D.21-03-056, the Commission adopted an effective PRM of 17.5% for the IOUs.

19. The weather experienced throughout the summer of 2020 and 2021 was extreme, and we must plan in anticipation of more frequent extreme weather events resulting from climate change.

20. Because a resource such as solar is unavailable at net peak because the sun has set, it does not contribute to the need at net peak.

21. CAISO's testimony reflects a significant shortfall in LSE supply plan resources at net peak.

22. The load impacts of the new and voluntary programs we adopt, and continue, in this decision cannot be predicted with certainty.

23. A large quantity of new resources will come online in 2022 and subsequent years as a result of recent IRP procurement decisions.

24. There is risk that the over 40 LSEs responsible for new IRP procurement will not bring all of the ordered resources online by the deadlines ordered in the IRP proceeding.

25. A recently released Energy Division report on the status of the August 2021 tranche of resources ordered in the D.19-11-016 procurement order indicates that a number of projects expected by August 2021 were delayed.

26. Much new IRP procurement will be performed by LSEs that are relatively new, have never procured new resources in the quantities they have been ordered to procure, or both.

27. Adding the procurement of contingency resources to these existing challenges would only serve to further increase these challenges.

28. Applying the TAC area CAISO load shares for each utility's service territory to the contingency procurement set forth in this decision results in target procurement amounts of 900 MW-1,350 MW each for PG&E and SCE service territories and 200 MW-300 MW for SDG&E service territory.

29. The CEC's peak demand forecast for the CAISO TAC area for the 2022 summer months is approximately 45,000 MW, so each 1,000 MW is equivalent to approximately a 2.5% increase in the PRM for CPUC jurisdictional entities.

30. Added to the 15% PRM requirement in the RA program that applies to all LSEs, the adopted range of additional contingency procurement results in an effective PRM of 20% to 22.5%.

31. Uncertainty regarding whether there is adequate supply in an extreme weather event will persist into 2023.

32. Procurement of contingency resources for summer 2021 resources approached but did not fully reach the 1,000 MW target adopted in D.21-03-056 in all summer months.

33. The IOUs collectively reached approximately 800 MW of D.21-03-056 ordered resources for August 2021, and surpassed the target in September 2021 with approximately 1,150 MW.

34. There is potential for delays associated with procurement already underway in compliance with the recent IRP decisions (D.21-06-035 and D.19-11-016) due to interconnection queue limitations, supply chain issues being faced as a result of the COVID-19 pandemic, high global demand for battery storage, and challenges with skilled labor availability for engineering and construction of new energy resources.

35. It may be difficult to identify and procure sufficient demand and supply-side resources to reach 2,000 MW of online and available contingency resources for summer 2022, let alone the 3,000 MW target.

36. It may not be possible to reduce the reliability risk in summers 2022 and 2023 to zero during an extreme weather event.

37. The procurement ordered here has a longer lead time than the 2021 contingency procurement ordered in Phase 1.

38. De-rating a solar resource's ability to serve a new net peak PRM standard without reviewing how other resources serve load at net peak may be an over-simplification of a complex planning problem.

39. The nameplate capacities of natural gas plants are de-rated to reflect their output during gross peak when temperatures are typically at their highest levels and output is most impacted, and wind speeds typically begin picking up in the evening hours compared to the gross peak.

40. The CAISO's analysis uses a net peak forecast for 2021 that is approximately 1,100 MW lower than the August 2022 net peak forecast used in the CEC's stack analysis.

41. The CAISO's analysis in its testimony uses resources included on August 2021 supply plans, and excludes 2021 IRP resources ordered in D.19-11-016 that were not online by August 2021 and the 850 MW of 2022 IRP resources ordered online by August 2022 in D.19-11-016.

42. A 2.5% adjustment to the PRM represents approximately 1,000 MW for CPUC jurisdictional entities' share of CAISO load, so achieving a 17.5% PRM at net peak would require 1,000 MW of resources in addition to the 2,000 MW of procurement needed to meet the 15% PRM at net peak.

43. After adjusting for August 2022 demand forecast and supply differences compared with August 2021, CAISO's proposed net peak RA requirement results in a need for 2,000 MW of additional resources available at net peak to achieve a 15% PRM and 3,000 MW to achieve a 17.5% PRM.

44. On September 8, 2021, the CEC adopted its 2022 Summer Stack Analysis. The CEC analysis provides a snapshot of an extreme weather event coupled with

conservative assumptions on availability of hydroelectric and imported resources and the potential need for contingencies in summer 2022. The CEC may consider adjustments to its peak load forecast in 2022.

45. A risk stacking approach is a different approach to need determination from traditional electricity resource planning. Resource planners forecast the probability of a loss of load event based on historic variations in weather, electricity demand, and resource performance.

46. Traditionally, California resource planning uses a "probabilistic" approach – that is, it considers various scenarios, rather than a single worst-case scenario. The CEC analysis takes a "deterministic" approach that assumes all worst-case scenarios occur simultaneously.

47. The CEC analysis assumes a 40% reduction in the DR resources that will be available in the future based on DR performance described in the Final Root Cause Analysis of the Mid-August 2020 Extreme Heat Wave, which results in an assumed maximum of 1,000 MW in 2022.

48. The CEC analysis assumes that the Redondo Beach once-through-cooling generating station (834 MW) will retire in 2021.

49. On October 19, 2021, the California Water Resources Control Board approved extension of the Redondo Beach generating station, which delivers 834, for two years.

50. The Commission's Load Impact Protocol process estimates the load impact of DR programs for the upcoming year. There is a lag in this analysis because DRPs estimate performance for the year ahead. Filings in 2021 include projected estimates of resources that will be available in 2022, based on analysis of DR resources' performance in 2020.

51. Using the Commission's Load Impact Protocol analysis, DR in aggregate performed closer to estimated levels during the August and September 2020 heat waves than a 40% discount assumed in other analyses.

52. Current summer 2022 DR authorizations for CPUC jurisdictional LSEs, IOU DR, DRAM contract estimates and third-party DRPs based on the Load Impact Protocol analysis of 2020 DR performance are approximately 1,650 MW.

53. If one adds to 1,650 MW the CEC's estimate of 2022 DR procurement by LSEs not under CPUC jurisdiction, the total DR value for 2022 is approximately 1,700 MW, or 700 MW more than the 1,000 MW value included in CEC's analysis.

54. The 2021 RA imports for July, August, and September 2021 were 5,800 MW, 6,000 MW, and 6,700 MW, respectively. Using these values rather than the multi-year averages results a reduction in the CEC net short estimate by approximately 500 MW for July and September and an increase in the net short by approximately 500 MW for August.

55. Phase 1 of this proceeding ordered 1,000 MW of resources.

56. The Commission should set a target range of new procurement rather than a point target because there is current and near-term uncertainty both in demand variation and resource availability.

57. Phase 1 of this proceeding adopted the ELRP as a pilot, and further refinements in this phase of the proceeding may allow for greater participation and benefit from the implementation of the program.

58. Disallowing non-residential participants that utilize backup generation that is positioned in disadvantaged communities from participating in the ELRP is one methodology that may eliminate some of the negative externalities that are caused by the execution of the ELRP.

59. Both customer Groups A and B have a day-of trigger, except for group A.6, Residential ELRP, which is only triggered in the day-ahead market.

60. $2.00/kWh is an appropriate compensation level for ELRP.

61. EVs can provide benefits to the grid by altering the time, charging level, or location at which grid connected EVs charge or discharge.

62. Technology capable of bi-directional EV charging is relatively new to the market and public uptake and awareness are low.

63. A minimum VGI dispatch hours of 30 hours per season in the EV/VGI pilot adopted here could provide an incentive for customers to participate in the program.

64. An EV/VGI pilot will help educate customers, aggregators, IOUs, and the Commission on the technology and systems needed to dispatch these resources.

65. A minimum VGI aggregation size of 25 kW may encourage aggregators to increase the pool of participants and reduce administrative costs for IOUs.

66. There are modifications to the DR programs of PG&E, SCE and SDG&E, as well as statewide modifications, that could result in greater participation in those programs and reduced load at the net-peak hours during stressed grid conditions, thus lowering the likelihood of an extreme weather-related blackout.

67. Adopting a pilot Residential ELRP may allow customers, IOUs, other stakeholders and the Commission to test and refine the program.

68. Compensating Residential ELRP customers to reduce their energy usage during CAISO Flex Alerts will promote equity and help achieve a greater load impact than without incentives. Robust marketing, education, and outreach along with behavioral DR tools that are attractive to customers such as personalized messaging, prompt performance results, or point systems may lead to higher participation rates.

69. The Commission has undertaken recent efforts to address affordability and promote equity in utility rates.

70. Many residential customers already participate in the Flex Alert program and do not receive compensation.

71. A Residential ELRP pilot that does not automatically enroll all residential customers will allow the Commission to observe enrollment levels, customer complaints, load reduction and other outcomes before committing the entire population of residential customers to a program.

72. Climate zones 9, 10, 11, 12, 13, 14 and 15 are hot climate zones.

73. Air conditioning load increases substantially in the summer months, and especially in hot climate zones.

74. Smart thermostats, when combined with a market-integrated, supply-side DR program, can automatically turn down air conditioning (*i.e.*, increase the temperature by a few degrees) during reliability events and thus reduce electric load.

75. For income-qualified customers eligible to participate in the Commission's ESA program, smart thermostat subsidies are already available for those customers in all climate zones.

76. The Commission has already adopted smart thermostat incentives for CARE/ESA-eligible customers without a DR requirement.

77. Low-income customers in the ESA program are eligible for a fully subsidized smart thermostat.

78. The existing smart thermostat Energy Efficiency-DR integration program the Commission adopted in D.18-05-041 involves installation of smart thermostats and other distributed energy resource technology measures through

the Commission's Energy Efficiency program, and captures DR benefits beyond energy savings.

79. Dynamic rates are time varying rates structured to provide incentives to customers to engage in energy consumption when demand is low, through rate differences.

80. In California, real time pricing rates have occasionally been offered on a pilot or optional basis.

81. Agriculture pumping has the capability to supply demand flexibility at low cost.

82. A dynamic rate pilot may provide data about the potential of dynamic rates for load shift.

83. Week ahead rate projections provide signals to agricultural customers on how to schedule pumping.

84. A shadow bill in the dynamic rate pilots adopted in this decision will allow customers to receive full payment for energy used during the pilots.

85. Collecting the costs of the UOS procurement ordered in this decision through distribution rates until the resource is fully deliverable to CAISO markets is consistent with principles of CAM treatment.

86. Distribution rates flow to all customers in an IOU's service territory, similar to CAM costs (which flow thorough a delivery charge to all benefiting customers).

87. A requirement for IOUs to submit an application for the UOS resources allowed in this decision may lead to delays in contract execution.

88. In its capacity as the CPE for local procurement, an IOU is best suited for the procurement of local resources through all-source solicitations to arrive at the least cost best fit set of options.

89. Given the near-term reliability needs to procure additional resources, the CPE is better suited to sign bilateral contracts for local procurement rather than an IOU's bundled procurement arm.

90. The August 2020 rotating outages and subsequent periods of stressed grid conditions in 2020 and 2021 involved high electricity demand that was not limited to the CAISO balancing authority area but was widespread across neighboring balancing authorities.

91. If reliability concerns extend outside California, the availability of imports into California can be speculative.

92. Day Ahead prices during the hours of concern in August 2020 did not reach the $1,000 price cap at which these unspecified imports regularly bid into the market.

93. Under current CAISO market rules imports have no obligation to bid into the real time markets.

94. Allowing generators and/or LSEs to offer the supply-side resources covered in this decision into RFOs or bilaterally negotiate with the IOUs for incremental capacity that can be brought online in 2022 or 2023 in advance of the IRP required August deadlines may allow for a market test of the price for accelerating these resources, since IOUs can compare offers of accelerating these projects with other resources being offered to meet their incremental procurement targets.

95. Contracts for procurement ordered in D.19-11-016 are already executed.

96. Penalties adopted in D.21-06-029 will not be implemented until 2022.

97. Emergency reliability procurement benefits all customers, whether bundled IOU customers or customers of other LSEs.

98. Phase 1 of this proceeding adopted the ELRP as a pilot, and further refinements in this phase of the proceeding may allow for greater participation and benefit from the implementation of the program.

99. There are different eligibility parameters for customer participation in ELRP, and those parameters are outlined as Group A and B customers with subsections within those groupings.

100. It is in the public interest for Group A.1 ELRP participant customers to be eligible to take service on a critical peak pricing or real-time pricing tariff while also participating in the ELRP.

101. An appropriate minimum size threshold parameter for Group A.1 Participants is 200 kW of peak demand in SCE's territory 100 kW of peak demand in SDG&E's territory.

102. There will be greater participation in the ELRP if Group A.2 eligibility is expanded to include non-BIP aggregators of non-residential, non-BIP customers that meet the criteria outlined in this decision.

103. An appropriate minimum aggregation size threshold for Group A.2 participants is 500 kW with the minimum dispatch hours set at 10 hours per season.

104. ELRP enrollment may be greater if stand-alone storage is eligible to participate as a Group A.4 eligible customer.

105. For Group B market-integrated resources, it is in the best interest of the administration of the ELRP for participating DRPs to list the PDR that will participate in ELRP and nominate an estimated target load reduction quantity to be achieved during an ELRP event by each participating PDR resource.

106. Clarifying that if Group B is triggered in the day ahead market, backup generators associated with customers participating in Group B and not exempted

under the Prohibited Resources policy and located in Disadvantaged Communities shall not be dispatched would reduce potential negative externalities from the dispatch of backup generators in the ELRP.

107. The requirement that ELRP compensation for an event be bounded for Group A participants between 50 and 200 percent of pre-nominated load shed or exported energy quantity is not necessary or beneficial for an effective implementation of ELRP.

108. The California State Emergency Program (CSEP), the emergency demand reduction program initiated by Governor's Newsom's July 30, 2021 emergency proclamation set a compensation level of $2/kWh.

109. Appropriate balancing account annual caps for program administration across all ELRP sub-groups, except ELRP sub-group A.6 (Residential customers) are PG&E $7.3 million, SCE $5.7 million, and SDG&E $3.0 million.

110. Appropriate balancing account annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, including the ELRP sub-group A.6 (Residential customers) are PG&E $94.0 million, SCE $76.6 million, and SDG&E $30.8 million.

111. Tariff amendments that the IOUs need to implement to effectuate the direction in this decision relative to DR programs should be requested from the Commission in a Tier 1 Advice Letter.

112. Additional capacity at net peak may be achieved by the IOUs procuring RA capacity from DRPs for 2022 and 2023 deliveries through bilateral contracts. This RA capacity could count toward any additional need that is assigned in this proceeding and any agreements could contain performance agreements to ensure delivery.

113. The IOUs should be authorized to pay upfront 100% of the eligible incentives for a custom Auto DR project on the condition that the customer's enrollment commitment to participate in an eligible DR program is extended from three years to five years. This modification should be effective for 2022 and 2023 only.

114. The alternative baseline adjustment option allowed by CAISO and already authorized for use in IOU Capacity Bidding Programs and Demand Response Auction Mechanism in D.21-03-056 should be used for calculating capacity performance in their respective Capacity Bidding Programs and Demand Response Auction Mechanism.

115. PG&E's proposal to implement a price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 could incent greater participation in the program.

116. PG&E's proposal to increase the current BIP compensation level by $1/kW for the months of May through October for the years 2022 and 2023 could incent greater enrollment in the program.

117. PG&E's proposal to create and manage a new out-of-market residential smart thermostat control pilot program could incent greater participation in demand reduction during times of need.

118. PG&E should replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program to incent greater participation in demand reduction during times of need.

119. PG&E's request for $1.2 million in incremental funds for Information Technology system enhancements should be granted to support third-party DR, and PG&E should use the one-way balancing account authorized in D.21-03-056 to track these expenses.

120. Non-residential customers enrolled in SCE's SDP could be permitted to dual participate in ELRP under the customer subgroup "A.1. Non-Residential, Non-DR Customers," and not be subject to the Minimum Size Threshold of subgroup A.1 as an effort to increase enrollment and decrease attrition.

121. SCE's proposal to reinstate the pre-cooling strategy where applicable in its SEP could slow the deterioration of load impacts and reduce opt-outs.

122. SCE's proposal to increase the ME&O budget for its SEP by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness should be approved.

123. To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for RDRR, SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that 1) the BIP and AP-I parameters match, and 2) the parameters for the SDP and SEP match should be approved.

124. SDG&E should continue in 2022 its CBP residential pilot approved in D.21-03-056 to ensure this relevant load reduction remains available.

125. SDG&E should create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives as proposed by SDG&E. SDG&E should be authorized to use existing funding for 2022, and is authorized $1.6 million for 2023, as well as a $51,000 incremental marketing budget.

126. IOUs have visibility into whether a customer is enrolled in a CCA's market integrated or supply-side DR programs.

127. The IOU in its role as Utility Distribution Company (UDC) tracks a customer's location registration in the CAISO Demand Response Registration System (DRRS).

Conclusions of Law

1. The Commission should adopt and LSEs including PG&E, SCE and SDG&E should be bound by the requirements of Attachments 1 and 2 to this decision.

2. The Commission should require procurement of additional supply- and demand-side resources that are available at net peak in summer 2022 and 2023.

3. The Commission should adopt a target procurement range of 2,000 MW to 3,000 MW in contingency resources for 2022 and 2023.

4. The Commission should continue the approach adopted in D.21-03-056 of authorizing the three large IOUs to procure additional resources to meet an "effective PRM."

5. The Commission should continue to order the large electric IOUs to pursue incremental demand and supply side resources for 2022, and extend the order to 2023.

6. The Commission should allocate procurement responsibility for the additional contingency resources ordered in this decision to the three large IOUs, using the same allocation ratios used for summer 2021 incremental procurement in the Phase 1 decisions.

7. The Commission should authorize the procurement of a wide variety of resources, some of which will be RA resources that will be visible to the CAISO on supply plans, while others will not be.

8. The Commission should prioritize the procurement of resources that are RA eligible and that will be visible to the CAISO in supply plans and participate in CAISO markets to the extent feasible.

9. There should be sufficient resources in place to meet demand during the net peak hour.

10. The additional resources ordered in this decision to meet the 2,000 MW to 3,000 MW range should be available at peak and net peak.

11. The Commission should revise the ELRP pilots adopted in D.21-03-056 to ensure reliability at net peak in summer 2022 and 2023.

12. The Commission should adopt a Residential ELRP pilot. In its Residential ELRP pilot, the Commission should adopt targeted outreach for ESA, FERA, CARE and Disadvantaged Communities customers.

13. The Flex Alert paid media campaign budget should not be reduced from the 2021 budget for 2022 and 2023, should include outreach related to Residential ELRP, and messaging should include information about the Residential ELRP trigger (day-ahead Flex Alerts as well as the day-ahead "Alert" in the California Independent System Operator's Alert, Warning, Emergency signal.

14. The Commission should revise DR programs with the program design features described in Attachment 2 to ensure reliability at net peak in summer 2022 and 2023.

15. For the EV/VGI pilot adopted here as part of ELRP, any EVSE meter or sub-meter used should meet applicable standards established by the Commission if and when adopted.

16. The Commission should allow procurement of UOS to ensure reliability at net peak in summer 2022 and 2023.

17. The Commission should allow market-based approaches to accelerate procurement already ordered in its IRP proceeding, including project cost, but the Commission and IOUs should have discretion to reject such approaches to prevent gaming or overpriced resources.

18. The Commission should adopt two dynamic rates pilots to test how dynamic rates can help ensure reliability at net peak in summer 2022 and 2023.

19. The Commission should expand use of smart thermostats paired with DR to control air conditioning use by adjusting the temperature setting a few degrees to ensure reliability at net peak in summer 2022 and 2023.

20. The Commission should allow customers eligible for CARE and FERA to elect to participate in the ESA program and to receive smart thermostats at no cost to them. If they so elect, such customers may but are not required to enroll in a DR program to receive such a subsidy. Such CARE and FERA-eligible customers may receive outreach about enrollment in DR programs.

21. CARE and FERA-eligible customers may elect to participate in the new smart thermostat program adopted in this decision, if they are also offered option to receive the ESA smart thermostat subsidy with no DR requirement as an alternative.

22. IOUs may conduct the Energy Efficiency-DR integration activity adopted in D.18-05-041 without a third-party entity designing or implementing the program.

23. The Commission should not change the CAM authority granted in D.21-02-028 and D.21-03-056, and should extend that decision's allowance to the summer 2023 procurement ordered in this decision.

24. The Commission should adopt some of the proposals in the Staff Concept Paper to ensure reliability at net peak in summer 2022 and 2023.

25. The Commission should reject some of the proposals in the Staff Concept Paper that will not enhance reliability at net peak in summer 2022 and 2023.

26. Updated guidance regarding the dispatch of prohibited backup generation in the ELRP should be implemented to allow for reduced emissions while still allowing for the reliability benefit of allowing the generators to participate.

27. Group A.1, A.4, and A.5 ELRP and A.6 Residential ELRP participant customers should be eligible to take service on a critical peak pricing or real-time pricing tariff while also participating in the ELRP.

28. An appropriate minimum size threshold parameter for Group A.1 Participants of 200 kW of peak demand in SCE's territory and 100 kW of peak demand in SDG&E's territory should be adopted.

29. ELRP Group A.2 eligibility should be expanded to include non-BIP aggregators of non-residential, non-BIP customers that meet the criteria outlined in this decision.

30. An appropriate minimum aggregation size threshold for Group A.2 participants of 500 kW with the minimum dispatch hours set at 10 hours per season should be adopted.

31. Stand-alone storage should be eligible to participate as a Group A.4 eligible customer in the ELRP.

32. For Group B market-integrated resources, DRPs should list the PDR that will participate in ELRP and nominate an estimated target load reduction quantity to be achieved during an ELRP event by each participating PDR resource.

33. Any load reduction technology may be used during an ELRP event to achieve Incremental Load Reduction. Prohibited resources, except those operated by non-residential customers located in Disadvantaged Communities, may be

used when permitted by a Governor's Executive Order and in compliance with Rule 21 and other applicable regulations and permits, during an ELRP event to achieve Incremental Load Reduction, including during the overlapping period with an independently triggered event in a dual-enrolled DR program, but only for achieving load reduction incremental to any other existing commitment (e.g., under a dual-enrolled DR program). The existing Prohibited Resources policy still applies to IOU and third-party managed DR programs, excluding ELRP.

34. Both customer groups A and B should have a day-of trigger for a more agile implementation of the ELRP, except for Residential ELRP group A.6 that should have a day-ahead trigger.

35. $2.00/kWh should be the compensation level for ELRP.

36. The requirement that ELRP compensation for an event to be bounded for Group A participants between 50 and 200 percent of pre-nominated load shed or exported energy quantity should not be necessary for an effective implementation of ELRP.

37. Balancing account annual caps for program administration across all ELRP sub-groups, except ELRP sub-group A.6 (Residential customers), for PG&E of $7.3 million, SCE of $5.7 million, and SDG&E of $3.0 million should be adopted.

38. Balancing account annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, including the ELRP sub-group A.6 (Residential customers), for PG&E of $94.0 million, SCE of $76.6 million, and SDG&E of $30.8 million should be adopted.

39. There are modifications to the DR programs of PG&E, SCE and SDG&E, as well as statewide modifications, that could result in greater participation in those programs and reduced load at the net-peak hours during stressed grid

conditions, thus lowering the likelihood of an extreme weather-related blackout and should be adopted.

40. Tariff amendments that the IOUs need to implement to effectuate the direction in this decision relative to DR programs should be requested from the Commission in a Tier 1 Advice Letter.

41. Additional capacity at net peak should be achieved by the IOUs procuring RA capacity from DRPs for 2022 and 2023 deliveries through bilateral contracts. This resource capacity should count toward any additional need that is assigned in this proceeding and any agreements should contain performance agreements to ensure delivery.

42. The IOUs should be authorized to pay upfront 100% of the eligible incentives for a custom Auto DR project on the condition that the customer's enrollment commitment to participate in an eligible DR program is extended from three years to five years. This modification should be effective for 2022 and 2023 only.

43. The alternative baseline adjustment option allowed by CAISO and already authorized for use in IOU Capacity Bidding Programs and Demand Response Auction Mechanism in D.21-03-056 should be used for calculating capacity performance in their respective Capacity Bidding Programs and Demand Response Auction Mechanism.

44. PG&E's proposal to implement a price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 should be approved to incent greater enrollment in the program.

45. PG&E's proposal to increase the current BIP compensation level by $1/kW for the months of May through October for the years 2022 and 2023 should be approved to incent greater enrollment in the program.

46. PG&E's proposal to create and manage a new out-of-market residential smart thermostat control pilot program should be approved for 2022 and 2023 to incent greater participation in demand reduction during times of need.

47. PG&E should be authorized to replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program to incent greater participation in demand reduction during times of need.

48. PG&E's request for $1.2 million in incremental funds for Information Technology system enhancements should be approved to support third-party DR, and PG&E should use the one-way balancing account authorized in D.21-03-056 to track these expenses.

49. Non-residential customers enrolled in SCE's SDP should be permitted to dual participate in ELRP under the customer subgroup "A.1. Non-Residential, Non-DR Customers," and not be subject to the Minimum Size Threshold of subgroup A.1 as an effort to increase enrollment and decrease attrition.

50. SCE's proposal to reinstate the pre-cooling strategy where applicable in its SEP should be approved to slow the deterioration of load impacts and reduce opt-outs.

51. SCE's proposal to increase the ME&O budget for its SEP by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness should be approved.

52. To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for RDRR, SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that 1) the BIP and

AP-I parameters match, and 2) the parameters for the SDP and SEP match should be approved.

53. SDG&E should be authorized to continue in 2022 its CBP residential pilot approved in D.21-03-056 to ensure this relevant load reduction remains available.

54. SDG&E should be authorized to create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives as proposed by SDG&E. SDG&E should be authorized to use existing funding for 2022, and $1.6 million for 2023, as well as a $51,000 incremental marketing budget.

55. In D.20-06-002 in the RA proceeding, the Commission adopted a centralized framework for the procurement of local RA in the PG&E and SCE distribution service areas, beginning with the 2023 RA compliance year.

56. The Commission has designated the CPE to meet local area requirements on behalf of all customers in the IOUs service area.

57. In D.20-06-028, the Commission revised its rules for imports to count toward RA requirements. The Commission clarified its RA import rules to ensure that RA imports did not represent "speculative supply" that might not be available during stressed system conditions.

58. The new RA rules from D.20-06-028 count non-resource-specific imports toward RA requirements, provided that: a) The contract is an energy contract with no economic curtailment provisions; b) The energy is self-scheduled (or in the alternative, is bid in at a level between negative $150/MWh and $0/MWh) into the CAISO day-ahead and real-time markets at least during the Availability Assessment Hours throughout the RA compliance month, consistent with the MCC buckets; and c) The energy is delivered to the load-serving entity in accordance with the governing contract, consistent with the MCC buckets.

59. CODs (or contracts that are otherwise operationally consistent with the guidance in this decision) by June 1, 2022 should be preferred but resources with CODs by August 1, 2023 will be considered pursuant to this decision.

60. New resources that have not yet reached full capacity deliverability status but are capable of providing energy/grid reliability benefits during the peak and net peak periods should be considered pursuant to this decision.

61. If the IOUs elect to recover the costs of the emergency resources from all customers in its service territory during and beyond the emergency procurement period, then these resources should not count toward existing IRP requirements. If the IOU elects to recover the costs of the emergency resources from their bundled customers after the emergency procurement period, then the resource may count toward the IOU's IRP requirements.

62. UOS allowed in this decision should not displace existing resources in the interconnection queue.

63. If an IOU procures resources that are not fully deliverable, it should work with the Commission's Energy Division and the CEC to ensure that benefits are allocated to all LSEs once the emergency procurement period has ended.

64. The requirement established in D.21-06-035 obligating the IOUs to submit an application for utility-owned resources procured to meet IRP MTR resource requirements should not apply to UOS resources that are brought online in response to this order.

65. During the emergency period, resources procured by the CPE should be allowed to count toward reducing the CPE's local procurement obligation. The system capacity benefit of these resources should not be allocated to all LSEs to reduce their system obligations during the emergency period. After the

emergency period has ended, the system capacity benefit of these resources may be allocated to all benefiting LSEs consistent with other CPE procured resources.

66. Consistent with the direction in D.20-06-002 and procurement authorized in prior Advice Letter filings by PG&E, the CPE should be allowed to procure dispatch rights, or other means that stipulate how local resources bid into the energy markets, in order to meet system reliability in an expedited manner.

67. Under current reliability resource requirements, 4-hour storage resources are considered acceptable resources to meet the peak and net peak needs, though they may not be available throughout the entire peak and net peak period.

O R D E R

IT IS ORDERED that:

1. Attachments 1 and 2 to this decision are adopted in their entirety, and Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) shall comply with the requirements set forth therein. To the extent Attachments 1 and 2 contain requirements in addition to those in this decision, SCE, PG&E and SDG&E shall comply with those additional requirements. To the extent this decision contains requirements in addition to those in Attachments 1 and 2 to this decision, SCE, PG&E and SDG&E shall comply with those additional requirements.

2. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall pursue incremental demand- and supply-side resources for 2022 and 2023 to maintain reliability of the grid during extreme weather events.

3. In recognition of the continued tight grid conditions experienced this summer, the California Independent System Operator's testimony reflecting a significant shortfall in Load Serving Entity supply plan resources at net peak,

and the need for additional contingency resources identified in the California Energy Commission's Summer 2022 Stack Analysis, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) shall use their best efforts to meet a revised targeted procurement range of 2,000 megawatts (MW) to 3,000 MW for summers 2022 and 2023, which includes and is not additive to the targeted procurement of 1,000 MW of contingency resources adopted in Decision (D.) 21-02-028 and D.21-03-056 and results in an "effective PRM" of 20%-22.5%. Based on the proportional load share in each utility's service territory, the revised targeted procurement range represents 900 – 1,350 MW of additional procurement for SCE and PG&E, and 200 – 300 MW for SDG&E.

4. A Statewide Flex Alert paid media campaign program administered by Southern California Edison Company shall be continued in 2022 and 2023, as outlined in Attachment 1, to encourage ratepayers to voluntarily reduce demand during moments of a stressed grid in California. The paid media campaign shall include marketing and messaging and materials for the new Residential Emergency Load Reduction Program (ELRP) pilot, including the program triggers (day-ahead Flex Alerts, as well as day-ahead Grid Alerts (*i.e.*, the "Alert" stage of CAISO's Alerts, Warning, Emergency signal)), and discouraging use of Back Up Generators (BUGs) that use prohibited resources in the Residential ELRP pilot program. The Commission's Energy Division will work with the paid media campaign vendor on the specific messaging regarding triggers and BUGs, as well as other aspects of the campaign.

5. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall fund the paid-media Flex Alert campaign with funds collected from all benefitting customers (*i.e.,* bundled

investor-owned utility, Community Choice Aggregator, and Direct Access customers) using Public Purpose Program balancing accounts, with a cap of $22 million annually in 2022 and 2023, and up to 3% of that budget is authorized to cover administration costs.

6. Modifications to the Emergency Load Reduction Program administered by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be made, as outlined in Attachment 2, as a tool that can provide emergency load reduction and serve as an insurance policy against the need for future rotating outages.

7. Within 60 days of the effective date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall jointly file Tier 1 Advice Letters incorporating the new Emergency Load Reduction Program (ELRP) terms and conditions for Group A and B, respectively, adopted in this decision and set forth in Attachment 2. The filings shall include details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification and customer acknowledgment, Incremental Load Reduction measurement, and settlement.

8. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall establish one-way balancing accounts covering new costs that are specifically authorized to be incurred in this decision, including those regarding the development, implementation, and operation of the Emergency Load Reduction Program changes made in this decision, along with incentives paid under the program. The balancing accounts shall be effective as of the date of this decision.

Amounts recorded in the balancing accounts that are specifically authorized to be incurred in this decision shall be recoverable in the annual balancing account true-up Advice Letters. PG&E, SCE, and SDG&E shall file Tier 1 Advice Letters within five days of the issuance of this decision establishing the new one-way balancing accounts.

9. If Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company have existing balancing accounts for the Emergency Load Reduction Program, Demand Response Programs, or smart thermostat program adopted or modified in this decision, they shall use those balancing accounts to track costs of such programs, rather than establishing new one-way balancing accounts.

10. Modifications to the Demand Response (DR) programs of and procurement of new DR resources from third-party DR providers by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall be instituted, as outlined in Attachment 1, to make the DR resources more effective and more aligned with grid need.

11. The net costs associated with the supply side procurement by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall be passed through to all benefiting customers consistent with the existing Cost Allocation Mechanism. PG&E, SCE and SDG&E are directed to continue their procurement efforts and endeavor to achieve an effective 20% to 22.5% planning reserve margin for the months of concern. All procurement contracts shall be submitted to the Commission via a Tier 1 Advice Letter on a continuing basis, except for contracts for incremental imports, incremental utility owned resources, and incremental gas generation of five years or more. Tier 1 Advice Letters are not required, but

may be submitted, for incremental imports. Contracts for utility owned resources shall be submitted to the Commission via a Tier 2 Advice Letter. Contracts of five years or more for incremental generation at existing gas power plants shall be submitted to the Commission via a Tier 3 Advice Letter. Contracts for fossil-fuel development at new sites or for redevelopment or full repowering at existing or mothballed electric generation sites will not be considered.

12. As directed in Decision (D.) 21-03-056, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall continue to utilize unspent funds from their existing Demand Response (DR) budgets adopted in D.17-12-003, to the extent existing funds are available. To the extent that any tariff amendments are necessary to effectuate the DR program changes ordered in this decision, those changes should be documented in a Tier 1 Advice Letter, as well as the process for transferring balances within the investor-owned utility's DR Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

13. Pacific Gas and Electric Company (PG&E), Southern California Edison Company, and San Diego Gas & Electric Company shall procure Resource Adequacy capacity from eligible third-party Demand Response (DR) providers for 2022 and 2023 deliveries through bilateral contracts. The third-party DR resources shall be comprised of new resources incremental to all existing DR resources already committed to any load serving entity. The procured DR capacity shall be integrated into the California Independent System Operator (CAISO) markets as economic DR and must abide by all RA and CAISO rules. The procured DR capacity shall be exempt from the Load Impact Protocol process and count toward the overall megawatt targets established for each investor-owned utility (IOU) in this decision and must be available at peak and

net peak. Because these procured resources are incremental to IOUs' and all load serving entities' (LSEs') 15% Planning Reserve Margin, these resources need not be applied to any LSEs' Maximum Cumulative Capacity bucket cap calculation. The IOUs shall adopt the capacity penalty structure from PG&E's Capacity Bidding Program. The IOUs shall submit bilateral contracts and cost recovery proposal to the Commission through Tier 1 Advice Letters.

14. Pacific Gas and Electric Company's proposal to implement a price bid cap of $650/megawatt-hour for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 is approved.

15. Pacific Gas and Electric Company's (PG&E) proposal to increase the current Base Interruptible Program (BIP) compensation level by $1/kilowatt for the months of May through October for the years 2022 and 2023, is approved. For the BIP compensation level increase, PG&E is authorized to update its tariff to recoup the annual $1 million to $3 million in costs associated with this increase that it is unable to cover in 2022 through the budget of its current 2018-2022 funding cycle, as well as 2023 costs.

16. Pacific Gas and Electric Company's (PG&E) proposal to create and manage a new out-of-market residential smart thermostat control pilot program is approved for 2022 and 2023. PG&E is authorized to spend an incremental $17.5 million in incentives, administration, and marketing in 2022 and 2023 for this pilot. For the program to continue beyond 2023, this program must be market integrated (as supply-side Demand Response).

17. Pacific Gas and Electric Company (PG&E) is authorized to replace one-way thermostat control technology with newer two-way devices in 2022 and 2023 in its SmartAC program. PG&E is authorized an incremental $7 million in

funding in 2022 and 2023 for administration, marketing, and retention incentives for this device exchange.

18. Pacific Gas and Electric Company's proposal to make Information Technology system enhancements to bolster its "Share My Data" platform by improving scalability and performance is approved and cost recovery of $1.2 million in incremental funds is approved.

19. Southern California Edison Company's proposal to increase the Marketing Education and Outreach (ME&O) budget for its Smart Energy Program by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness, is approved.

20. San Diego Gas & Electric Company (SDG&E) is authorized to create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives. $1.6 million is authorized for this program for 2023, as well as a $51,000 incremental marketing budget.

21. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall continue to use the one-way balancing accounts authorized in Decision 21-03-056 regarding the development, implementation, and operation of the Emergency Load Reduction Program (ELRP), along with incentives paid under the program. These balancing accounts shall have the following annual caps for program administration across all ELRP sub-groups, except ELRP sub-group A.6 (Residential customers): PG&E $7.3 million, SCE $5.7 million, and SDG&E $3.0 million. Additionally, these balancing accounts shall have the following caps for Residential ELRP (sub-group A.6) program administration and marketing, education, and outreach. While these caps are listed by year, the

IOUs may shift funds between 2022 and 2023 as needed, but shall not use this flexibility to justify a new request for administrative costs for 2023. PG&E: 2022: $9.4 million for administration and $2.5 million for marketing, education, and outreach; 2023: $8.7 million for administration and $2.0 million for marketing, education, and outreach. SCE: 2022: $10.0 million for administration and $2.5 million for marketing, education, and outreach; 2023: $9.0 million for administration and $1.6 million for marketing, education, and outreach. SDG&E: 2022: $3.3 million for administration and $0.75 million for marketing, education, and outreach; 2023: $3.0 million for administration and $0.5 million for marketing, education, and outreach. Additionally, these balancing accounts shall have the following annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, including the ELRP sub-group A.6 (Residential customers): PG&E $94.0 million, SCE $76.6 million, and SDG&E $31.1 million.

22. The following Advice Letter filings related to the Emergency Load Reduction Program (ELRP) are either authorized or directed to be filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). Within 60 days of this Decision, PG&E, SCE and SDG&E shall jointly file a Tier 1 Advice Letter (AL) incorporating the modifications by this Decision to ELRP terms and conditions for Group A. Limited deviations to accommodate investor-owned utility (IOU) specific implementations due to information technology (IT) and billing systems are permitted. The filing shall include the details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification and customer acknowledgment, Incremental Load Reduction measurement, and settlement.

Within 60 days of this Decision, PG&E, SCE, and SDG&E shall jointly file a Tier 1 AL incorporating the modifications by this Decision ELRP terms and conditions for Group B. Limited deviations to accommodate IOU specific implementations due to IT and billing systems are permitted. The filing shall include the details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification, Incremental Load Reduction measurement, and settlement and invoicing. PG&E, SCE, and SDG&E may file Tier 1 ALs that request to defer implementation of certain ELRP design elements, where permitted, and shall include an explanation for why the delay is necessary or reasonable. As experience in ELRP is gained, the IOUs may seek to modify various aspects of ELRP design via an IOU-specific or joint IOU Tier 2 AL as appropriate before or by December 31 of each program year to manage program enrollment, improve program efficiency, increase potential load reduction available to ELRP, improve program value, and reduce program cost.

23. Programs authorized by and continued in this decision, such as the Emergency Load Reduction Program and dynamic rates pilots, shall count toward the contingency procurement targets addressed in this decision.

24. To participate in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program, aggregators shall meet the following criteria: a) The VGI aggregation or any customer site within the aggregation shall not be simultaneously enrolled in a market-integrated, supply-side Demand Response (DR) program offered by an Investor-Owned Utility (IOU), third-party DR Provider, or Community Choice Aggregator; b) A customer site within the VGI aggregation shall not be taking service on a critical

peak pricing or real time pricing-equivalent tariff; c) All sites within the VGI aggregation shall be located within the distribution service area of a single IOU; and d) the VGI aggregation shall contribute Incremental Load Reduction, as defined in Attachment 2, equal to or greater than the Minimum VGI Aggregation Size Threshold for a minimum of one hour. Such aggregators shall comply with all additional requirements of Attachment 2 to this decision.

25. Participants in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program adopted in this decision shall receive minimum VGI dispatch hours of 30 hours per season. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) have discretion to meet the 30-hour minimum by dispatching aggregators in response to forecasted or anticipated grid stress conditions, such as high locational marginal prices in the California Independent System Operator markets and extreme heat waves. PG&E, SCE and SDG&E may negotiate agreements with the VGI aggregators to clarify other requirements needed, including potential administration fees, to implement the dispatch hours and compensation.

26. Participants in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program adopted in this decision shall have a minimum VGI aggregation size of 25 kilowatts.

27. Participants in the Electric Vehicle and Vehicle-Grid Aggregation (VGI) aspects of the Emergency Load Reduction Program who use Electric Vehicle Supply Equipment (EVSE) shall meet applicable standards established by the Commission for EVSE meters and sub-meters.

28. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall

automatically enroll (that is, apply an opt out approach to) certain groups of residential customers in the Residential Emergency Load Reduction Program (ELRP). PG&E, SCE and SDG&E shall auto-enroll residential customers in the California Alternate Rates for Energy program and the Family Electric Rate Assistance program in the Residential ELRP. PG&E, SCE and SDG&E shall provide notifications to alert and engage customers about the program being triggered using methods such as email, phone call, text message, application notification, broadcast, bill insert or mailer. All customers may opt out of Residential ELRP at any time.

29. Customers of the Residential Emergency Load Reduction Program (ELRP) may not simultaneously be enrolled in another supply side Demand Response (DR) program offered by an Investor-Owned Utility (IOU), third-party DR provider or Community Choice Aggregator. Residential ELRP customers or ELRP group A.4 and A.5 customers may simultaneously be enrolled in a critical peak pricing, SmartRate or similar dynamic rate tariff and enroll in these ELRP programs, since IOUs do not have visibility into whether customers are taking service under critical peak pricing, SmartRate or similar dynamic rate tariffs.

30. A Community Choice Aggregator (CCA) may elect not to participate in the Residential Emergency Load Reduction Program (ELRP) pilot adopted in this decision, in which case its customers are ineligible to enroll. The CCA shall make its election by January 31 of each new Residential ELRP pilot year.

31. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall establish a process for a Community Choice Aggregator (CCA) to inform them of the CCA's election to exclude its customers from the Residential Emergency Load Reduction Program.

32. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall promptly unenroll customers participating in Residential Emergency Load Reduction Program that enroll in a supply-side Demand Response (DR) program offered by the Investor-Owned Utility, registered third-party DR provider or Community Choice Aggregator without the need for any action on the part of the customer.

33. To the extent customers are not automatically enrolled in the Residential Emergency Load Reduction Program (ELRP), Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall devise an easy process for eligible customers to be able to opt in to the Residential ELRP.

34. Pacific Gas and Electric Company's (PG&E) Power Savers Rewards Program, Option A, with auto-enrollment of customers who receive PG&E's Home Energy Reports, is approved. PG&E's Options B and C are not approved.

35. Southern California Edison Company's Whole Home Savings Pilot, with auto-enrollment of high usage customers who have opted in to receive transactional emails, is approved. Dual participation in another Demand Response program is not permitted.

36. San Diego Gas & Electric Company's (SDG&E's) "Peak Day" Behavioral Demand Response program, with auto-enrollment of existing Home Energy Report customers, is approved as the basis for SDG&E's select group of customers who will be auto-enrolled into Emergency Load Reduction Program.

37. In their marketing, education, outreach, and event notification efforts focused on the auto-enrolled California Alternate Rates for Energy (CARE) customers, as well as Energy Savings Assistance (ESA) program customers, Family Electric Rate Assistance (FERA) program customers, and customers in

Disadvantaged Communities, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall provide in-language accessibility and specific outreach for CARE, ESA, FERA, and Disadvantaged Community customers, as described in Attachment 2 to this decision.

38. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall use a California Independent System Operator (CAISO) issued Flex Alert declaration or day-ahead CAISO "Alert" declaration (part of CAISO's Alert, Warning, Emergency system) as the trigger for dispatching Residential Emergency Load Reduction Program (ELRP) customers. PG&E, SCE and SDG&E shall collaborate to establish common program parameters, including a minimum dispatch window (which must be at least 2 hours), the start time of the dispatch, marketing strategies that limit customer confusion by ensuring that individualized messaging from PG&E, SCE and SDG&E is consistent with the messaging from the statewide Flex Alert campaign, and statewide unified branding. PG&E, SCE and SDG&E shall each file a Tier 2 Advice Letter within 30 days of issuance of this decision to establish the parameters and proposed cost of its ELRP Residential pilot program.

39. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall have discretion to determine the proper baseline against which Incremental Load Reductions will be calculated and compensated in the Residential Emergency Load Reduction Program. After the first program year, and no later than January 15, 2023, PG&E, SCE and SDG&E shall evaluate the baseline methodology. PG&E, SCE and SDG&E shall submit a joint report to the

Commission's Energy Division no later than January 15, 2023, with a copy to the service list for this proceeding and such other parties Energy Division shall specify, reminding parties of this baseline evaluation requirement and outlining their approach to the evaluation.

40. With regard to the Residential Emergency Load Reduction Program (ELRP) pilot, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall validate that the customer is not enrolled an Investor-Owned Utility (IOU) Demand Response (DR) program. If the IOU sees that a Community Choice Aggregator or third-party DR provider registers a customer location in the California Independent System Operator Demand Response Registration System, the IOU at that time shall unenroll the customer from the Residential ELRP pilot.

41. Customers in the smart thermostat program adopted in this decision shall pre-enroll in a California Independent System Operator market integrated Demand Response (DR) program that is administered by either an Investor-Owned Utility or third-party DR provider.

42. The smart thermostat program budget is authorized at up to $22.5 million in technology incentives to be available over a two-year period, from 2022 to 2023. The program rebate amount for participants is $75, not to exceed the full cost of the smart thermostat equipment, and shall be uniform across all program implementers. Prior to incentive payment, the Investor-Owned Utility (IOU) serving the customer shall certify installation of an eligible thermostat and enrollment in an eligible IOU or third-party supply-side Demand Response program.

43. Fifty percent of the technology incentive budget of the smart thermostat program, or up to $11.25 million, shall be available to third-party Demand

Response (DR) Providers (DRPs) to provide rebates through the third-party supply-side DR programs. The third-party DRPs shall have competitively equal access to the rebates as the Investor-Owned Utilities (IOUs). IOUs may request up to an additional 10% of the technology incentive budget of each IOU's proportional share for administrative costs, with a total cap on such costs for all three IOUs at $2.5 million. Each IOU must justify the amount of administrative budget that will be required to administer the program in the joint Tier 2 Advice Letter filing this decision requires.

44. The smart thermostat program adopted in this decision is available for customers in climate zones 9, 10, 11, 12, 13, 14 and 15.

45. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall jointly file a Tier 2 Advice Letter with details of the smart thermostat program adopted in this decision.

46. Within 15 days of issuance of this decision Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (collectively, IOUs) shall meet and confer with third-party Demand Response (DR) Providers (DRPs) to discuss the process to distribute rebate awards, and to certify smart thermostat installation and DR program enrollment. The IOUs may use existing processes for reimbursing customers to avoid operational challenges and delays. Within 45 days of issuance of this decision, the IOUs shall jointly file a Tier 2 Advice Letter that reflects a consensus across third-party DRPs and IOUs on the foregoing issues. The joint Advice Letter shall include the following items:

- Program design and budget;
- How funds and administration of program will be split among the three IOUs, consistent with the direction in this decision

- Amount of administrative budget up to 10% of proportional share of the technology incentive budget each IOU will need to administer the program;
- A discussion of any balancing or memorandum account authorization sought to track program expenditures;
- Goal for number of customers reached, by when, and estimated megawatt demand savings;
- Identification of qualifying thermostats eligible for the $75 incentive;
- A process to ensure customers of both IOUs and third-party DRP programs are eligible for smart thermostat incentives;
- A description of the DR programs a customer must enroll in to be eligible for the thermostat incentive, and how that enrollment will occur before the customer receives a rebate;
- Implementation details including whether proof of purchase is needed for reimbursement, whether customers with existing eligible thermostats are eligible if not already enrolled in a DR program, number of thermostats per account, disqualification of customers with free thermostats; and
- The process for identifying customers who qualify for the Energy Savings Assistance or California Alternate Rates for Energy program.

47. The smart thermostat technology incentive of $75 may not be combined or "stacked" with thermostat technology incentives provided by the existing Auto Demand Response program. Prior to incentive payment, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall certify installation of an eligible thermostat and enrollment in an eligible Investor-Owned Utility or third-party market integrated supply-side Demand Response program. Eligible market integrated programs are the

Demand Response Auction Mechanism, Smart Energy Program, Capacity Bidding Program-Residential, and AC Saver.

48. With regard to smart thermostats, a customer eligible for California Alternate Rates for Energy or the Energy Savings Assistance (ESA) program may decide to obtain the smart thermostat through the ESA program in any climate zone, or through the smart thermostat program adopted in this decision, and providers shall present both options to such customers and allow voluntary election. If such customer chooses to receive a smart thermostat from the program adopted herein, the customer must pre-enroll in a market integrated supply-side Demand Response (DR) program, but can still participate in the ESA program for an additional energy efficiency treatments at no cost. If the customer chooses to participate in the ESA program, the Investor-Owned Utilities and their ESA contractors, during their in-person assessment and installation, shall promote but not require enrollment in a market-integrated supply-side DR program.

49. In implementing the Integrated Demand-Side Management Program Guidance in this decision and Decision (D.) 18-05-041, the Investor-Owned Utilities (IOUs) shall file a Tier 2 Advice Letter within 90 days of issuance of this decision that should specify: remaining budget from the originally authorized budget in D.18-05-041; how the remaining budget should be allocated among the IOUs to run their integrated Energy Efficiency-Demand Response programs; and program implementation plans and design, including information on how they comply with requirements outlined in D.18-05-041.

50. Valley Clean Energy's (VCE) dynamic rate pilot for agricultural water pumping is approved. Pacific Gas and Electric Company shall work with VCE on implementation. Non-generation and non-delivery costs (*e.g.*, transmission

rates and non-bypassable charges) of the pilot shall be recovered through existing rate structures. The pilot scale shall be limited to 5 megawatts of peak load.

51. Customers participating in Valley Clean Energy's (VCE) dynamic rate pilot approved in this decision will receive a "shadow bill." Pacific Gas and Electric Company (PG&E) may bill participating customers based on existing tariffs, but the shadow bill will show the customer savings under the pilot dynamic rate, and VCE, and if necessary, PG&E, shall pay customers for the difference between the shadow bill and the existing tariff.

52. The Valley Clean Energy dynamic rate pilot approved in this decision is authorized for three years (2022-2024), and shall start no later than May 1, 2022.

53. In implementing the Valley Clean Energy (VCE) dynamic rate pilot approved in this decision, VCE, in consultation with Pacific Gas and Electric Company (PG&E), may engage a service provider with a suitable Information Technology platform to automate dynamic hourly prices and make them accessible to customers and automated agricultural water pumps. For the generation components of the service by VCE, (1) energy costs shall be based on the California Independent System Operator wholesale market prices, and (2) generation capacity and flexible capacity costs shall be recovered on an hourly basis using the scarcity pricing concept: more fixed costs are recovered when system utilization is higher relative to the system capacity limit. For the delivery component of the service by PG&E, (1) line losses will be recovered through volumetric rates, which could be time dependent, and (2) distribution capacity costs will also be recovered on an hourly basis using the scarcity pricing concept in lieu of monthly or annual demand charges.

54. Pacific Gas and Electric Company (PG&E) shall credit any savings realized by the customers with respect to the delivery component of the Valley Clean Energy dynamic rate pilot in the customers' shadow bills. PG&E shall set up a two-way balancing account to track expenses related to the delivery component of the customer bill savings during the pilot.

55. Pacific Gas and Electric Company (PG&E), in coordination with Valley Clean Energy (VCE) shall contract an independent evaluator and submit a midterm evaluation of the VCE dynamic rate pilot program no later than December 31, 2023, and a final evaluation no later than March 1, 2025. The evaluations shall include the following elements:

- The response of agricultural loads to prices, including the response to non-binding week ahead price projections. This should evaluate the efficacy of the pilot tariff in shifting agricultural loads enrolled in the program from peak to off-peak periods and should be compared to other VCE agricultural loads;
- In the case that VCE incorporates binding forecast projections, the evaluation should also include an assessment of this element;
- The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff;
- An evaluation of the recovery of generation and resource adequacy costs for customers on the pilot tariff. This evaluation should assess the impact of any under collection of generation and resource adequacy revenues against the impact of the shifted participant loads on marginal generation and resource adequacy costs, and on the avoided cost value, including using the Commissions' Avoided Cost Calculator, where appropriate; and
- An evaluation of the recovery of delivery costs for customers on the pilot tariff. This evaluation should assess the impact of any under-collection of delivery revenues

against the impact of the shifted participant loads on marginal delivery costs, and on the avoided cost value, including using the Commissions' Avoided Cost Calculator, where appropriate.

56. Valley Clean Energy (VCE) shall be primarily responsible for the recruitment, integration, and automation of the pumping loads. Pacific Gas and Electric Company shall coordinate with VCE to fund customer integration and automation expenses.

57. Valley Clean Energy (in coordination with Pacific Gas and Electric Company shall submit a Tier 2 Advice Letter no later than 30 days after issuance of this decision that includes the following elements of its dynamic rates pilot: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, (5) pilot tariff design, and (6) details of how circuit and system data will be used to calibrate and calculate tariff price curves.

58. Pacific Gas and Electric Company (in coordination with Valley Clean Energy (VCE)) shall submit a Tier 2 Advice Letter no later than 60 days after issuance of this decision that includes the following elements of the VCE dynamic rates pilot: (1) details of how circuit utilization data from the distribution circuits that serve VCE customers will be used to calibrate and calculate the delivery component of the dynamic prices, (2) details of how the circuit utilization data will be integrated with the pilot IT platform, and (3) the administration and evaluation budgets for this pilot.

59. Southern California Edison Company (SCE) is authorized to conduct a dynamic rate pilot for the purpose of studying how price responsive pilot projects can enhance system reliability in 2022 and 2023. As further set forth in Attachment 1, the pilot is open to SCE residential, commercial, and industrial customers, and SCE may prioritize customers with smart enabling

price-responsive end-uses such as electric vehicle charging, behind-the-meter batteries, and controllable loads.

60. Southern California Edison Company's dynamic rate pilot is authorized for three years (2022-2024), starting no later than May 1, 2022.

61. In its dynamic rate pilot authorized in this decision, Southern California Edison Company (SCE) may use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot prices. In such an approach, participants will continue to pay their current SCE bill under the otherwise applicable tariff and will also receive a shadow pilot bill, which they will not pay, that illustrates a customer's potential savings under the pilot rate. SCE shall make payments to participants in the program for their pilot rate savings on either a monthly or annual basis.

62. Southern California Edison shall conduct a mid-term and final evaluation of its dynamic rate pilot approved in this decision to assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts. The mid-term report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025. The evaluations shall include the following elements:

- An evaluation of load responsiveness. SCE should evaluate the efficacy of the pilot tariff in shifting loads enrolled in the program from peak to off-peak periods and should be compared to non-participant loads;
- The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff; and
- An evaluation of the cost recovery which assess the impact of any under-collection of revenues associated with the pilot similar to the evaluation required of the Valley Clean Energy dynamic rate pilot.

63. Southern California Edison Company shall submit a Tier 2 Advice Letter for its dynamic rate pilot no later than 30 days after issuance of this decision that includes, but is not limited to, the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, and (5) pilot tariff design.

64. For supply side resources ordered to be procured in this decision, resources a) must be available during both the peak and net peak demand periods; b) are preferred to have Commercial Online Dates (COD) (or contracts that are otherwise operationally consistent with the guidance in this decision) by June 1, 2022, but resources COD or operational by August 1, 2023,will be considered; c) need not yet have full capacity deliverability status but must be capable of providing energy/grid reliability benefits during the peak and net peak periods; and d) may include utility-owned storage, with Commission consideration of such projects through a Tier 2 Advice Letter.

65. Supply side resource types that may be considered for the procurement adopted in this decision are:

- Acceleration of Commercial Online Dates from a resource that is otherwise required to meet a Load Serving Entity's IRP target, *e.g.* acceleration to June 1, for a resource that would otherwise be online by August 1.
- Incremental energy storage, including utility-owned storage.
- Firm forward imported energy, as well as import contracts that ensure delivery during tight system conditions (*e.g.*, alerts, warnings, and emergencies or at contractually pre-specified prices) but the latter category can only be procured by Investor-Owned Utilities and applied to the incremental reliability procurement targets adopted in this decision.
- Contracting for generation that is at-risk of retirement.

- o Incremental capacity from existing power plants through efficiency upgrades, revised power purchase agreements/tolling arrangements.

66. For the supply side procurement ordered in this decision, Resource Adequacy-only contracts or contracts that include dispatch rights or other means that stipulate how resources bid into the energy markets may be proposed.

67. A Tier 3 Advice Letter shall be filed for contracts of five years or more for efficiency improvements resulting in incremental generation at existing gas power plants.

68. For the supply side procurement ordered in this decision, counterparties may include in their bids or contract proposals a price element that accelerates Commercial Online Dates

69. For the supply side procurement ordered in this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for the months of concern. These efforts should take the form of solicitations, ongoing bilateral negotiations, Investor-Owned Utilities offering counterparties an opportunity to refresh prior Integrated Resource Plan (IRP) procurement bids, accelerated procurement of resources procured by Load Serving Entities to meet their IRP obligations for summer months prior to their required online dates, upgrades resulting in increased efficiency of existing generation resources, and imports.

70. All Resource Adequacy (RA)-eligible resources supporting the effective Planning Reserve Margin (PRM) adopted in this decision shall be included in supply plans and Investor-Owned Utilities' (IOU) month ahead RA showings to

ensure that these resources are subject to RA obligations and incentive mechanisms, do not receive Capacity Procurement Mechanism double payments, and are visible to the California Independent System Operator as RA resources not eligible for export. Only costs associated with RA resources in excess of an IOU's own 15% PRM should be charged to all benefiting customers in the IOU's service territory via the Cost Allocation Mechanism.

71. To the extent feasible, Investor-Owned Utilities (IOU) shall pair imports contracted with maximum import capacity and include these costs in their Cost Allocation Mechanism procurement costs. If existing IOU-owned maximum import capacity is paired with imports to construct a Resource Adequacy product, the IOU shall calculate and include the average price it received for sales of its excess maximum import capability or, if not available or representative of market value, another reasonable market benchmark.

72. If an Investor-Owned Utility has not met its minimum contingency procurement target for the months of June and October with Resource Adequacy (RA)-eligible resources that can be reflected on supply plans, it may use excess resources in its existing portfolios to meet the minimum contingency procurement target (900 megawatts (MW) for Pacific Gas and Electric Company and Southern California Edison Company, and 200 MW for San Diego Gas & Electric Company), provided it has made reasonable attempts to sell this excess capacity to other Load Serving Entities. In these instances, the excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment RA System Market Price Benchmark.

73. For the months of July, August, and September, excess resources from an Investor-Owned Utility's existing portfolios may be used to meet or supplement procurement targets in this decision up to the upper end of its contingency

procurement target (1,350 megawatts (MW) for Pacific Gas and Electric Company and Southern California Edison, and 300 MW for San Diego Gas & Electric), provided it has made reasonable attempts to sell this excess capacity to other. These excess resources may be accounted for at the imputed cost of 2021 Power Charge Indifference Adjustment Resource Adequacy System Market Price Benchmark.

74. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall provide the monthly amounts of the excess resources they applied to the Cost Allocation Mechanism, as well as the calculus used to determine these amounts to Commission's Energy Division, and Energy Division will post this information on the Commission's website.

75. To the extent that any additional adjustments to balancing accounts are needed to provide for Cost Allocation Mechanism cost recovery of the procurement authorized in the decision, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company may file Tier 2 Advice Letters with the effective date of the tariff modification to be the effective date of this decision.

76. Energy storage that can be brought online by summer 2022 or 2023 to meet the procurement targets, identified above, may be both utility-owned storage and third-party resources. These storage resources need not be fully deliverable in 2022 or 2023, as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023. We encourage siting these resources in locations where they will also provide benefits to local reliability and Disadvantaged Communities.

77. Incremental energy storage that can be brought online by summer 2022 or 2023 to meet the procurement targets in this decision may be both Utility Owned

Storage and third-party resources. These storage resources need not be fully deliverable in 2022 or 2023, as long as they provide peak and net peak grid reliability benefits in summer 2022 or 2023. Resources that are not fully deliverable are allowed only to resources that are being brought online to meet the 2022 and 2023 summer reliability procurement authorized in this decision.

78. Southern California Edison Company's cost allocation for its utility owned storage procurement as a distribution system asset rather than a generation asset resource is approved as an acceptable alternative to the Cost Allocation Mechanism (CAM) authority granted in Decision 21-02-028 when operating the resources as non-California Independent System Operator (CAISO)-controlled grid assets prior to deliverability to CAISO markets while CAISO deliverability studies are performed since the rate impact is the same (distribution assets and CAM resources are charged to all customers) and it accomplishes the same grid benefit.

79. Consistent with the principles of the Cost Allocation Mechanism (CAM) authority this Commission granted in Decision 21-02-028, once a resource authorized in this decision is connected to the transmission system and deliverable to California Independent System Operator markets, Investor-Owned Utilities shall no longer collect costs for the resources through distribution rates, and instead shall account for the net capacity costs and benefits through the CAM mechanism.

80. The Tier 2 Advice Letter process and Cost Allocation Mechanism for utility owned storage adopted in Decision (D.) 21-02-028 is authorized for continue for 2022 and 2023. The Integrated Resource Plan (IRP) requirement established in D.21-06-035 obligating the Investor-Owned Utilities to submit an application for

utility-owned resources procured to meet IRP requirements is not required for the procurement authorized in this decision.

81. Southern California Edison Company and Pacific Gas and Electric Company may negotiate bilateral contracts for the emergency procurement ordered in this decision in local reliability areas in their capacities as Central Procurement Entities (CPE). For purposes of the procurement authorized in this decision, CPEs may also use all-source solicitations to procure local area resources. Such resources shall be limited to energy storage and preferred resources. CPEs shall submit such procurement contracts to the Commission via Tier 1 Advice Letters on a rolling basis.

82. Certain Resource Adequacy (RA) rules with regard to imports for Investor-Owned Utilities are relaxed with regard to imports used to meet the authorized procurement in this decision. Import contracts that do not meet import requirements because they are executed after the month-ahead showing process may be executed to meet the effective Planning Reserve Margin (PRM) adopted in this decision. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company may execute import contracts for the effective PRM that do not meet the RA import requirements but are structured to ensure delivery during tight system conditions (*e.g.,* California Independent System Operator Alerts, Warnings, and Emergencies or at contractually pre-specified prices).

83. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall work with the Commission's Energy Division to show late procured imports to meet the effective Planning Reserve Margin adopted here as Resource Adequacy resources under the California Independent System Operator's market mechanisms on supply plans.

84. All Load Serving Entities and project developers may bid into the Investor-Owned Utilities' solicitations or contract bilaterally for accelerated procurement of 2022 resources. We decline to adopt an incentive regime for such accelerated procurement.

85. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are relieved from the obligation in Decision 19-11-016 of filing Tier 3 Advice Letters for approval of their contracts with Once Through Cooling (OTC) units if the units are needed for emergency reliability authorized in this proceeding or to address other reliability needs, such as Resource Adequacy requirements. These Investor-Owned Utilities may contract with OTC units through 2023 under their Bundled Procurement Plan authority without the requirement to file a Tier 3 Advice Letter.

86. The Cost Allocation Mechanism (CAM) authority granted in Decision (D.) 21-02-028 and D.21-03-056 is extended to the summer 2023 procurement ordered in this decision. If an Investor-Owned Utility (IOU) uses such procurement to meet its bundled service Resource Adequacy (RA) requirements, it shall not recover the costs of the resource through CAM, but rather from bundled service customers. After the emergency procurement period, during which an IOU procures incremental reliability resources on behalf of all customers, ends, the IOU shall allocate RA benefits of any resources whose contracts extend beyond the emergency procurement period consistent with their approved cost recovery mechanism.

87. For the supply-side resources allowed in this decision, Commercial Online Dates (CODs), or contracts that are otherwise operationally consistent with the guidance in this decision, by June 1, 2022 are preferred but resources with CODs by August 1, 2023 will be considered.

88. New supply-side resources that have not yet reached full capacity deliverability status but are capable of providing energy/grid reliability benefits during the peak and net peak periods described in this decision will be considered.

89. Emergency reliability resources procured to meet the requirements of this decision may count toward existing Integrated Resource Plan (IRP) requirements. If an Investor-Owned Utility (IOU) elects to recover the costs of the emergency resources from all customers in its service territory during and beyond the emergency procurement period, then these resources will not count toward IRP requirements. If the IOU elects to recover the costs of the emergency resources from their bundled customers after the emergency procurement period, then the resource may count toward their IRP requirements.

90. Utility Owned Storage allowed in this decision shall not displace existing resources in the interconnection queue.

91. If an Investor-Owned Utility procures resources that are not fully deliverable, it shall work with the Commission's Energy Division and the California Energy Commission to ensure that benefits are allocated to all Load Serving Entities once the emergency procurement period has ended.

92. The requirement established in Decision 21-06-035 obligating the Investor-Owned Utilities to submit an application for utility-owned resources procured to meet Integrated Resource Plan Mid-term Reliability resource requirements does not apply to Utility Owned Storage resources that are brought online in response to this decision.

93. During the emergency period, resources procured by the Central Procurement Entity (CPE) may count toward reducing the CPE's local procurement obligation. However, the system capacity benefit of these resources

will not be allocated to all Load Serving Entities (LSE) to reduce their system obligations. After the emergency period has ended, the system capacity benefit of these resources will be allocated to all benefiting LSEs consistent with other CPE procured resources.

94. The list of eligible procurement of supply-side resources in this decision may include contracts that include dispatch rights or other means that stipulate how resources bid into the energy markets.

95. Investor-Owned Utilities (IOUs) are not required to submit a Tier 3 Advice Letter for Once Through Cooling (OTC) plants needed to meet any reliability needs, including Resource Adequacy compliance requirements, putting the IOUs on a level playing field with other Load Serving Entities, which are not required to obtain Commission approval to sign OTC contracts.

96. All testimony served in Phase 2 of this proceeding is admitted into evidence in this proceeding.

97. Rulemaking 20-11-003 closed.

This order is effective today.

Dated December 2, 2021, at San Francisco, California.

MARYBEL BATJER
President
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE HOUCK
Commissioners

ATTACHMENT 1

Attachment 1 Table of Contents

1. Flex Alert

A Statewide Flex Alert Paid Media campaign shall continue to be funded by the ratepayers of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), together, the investor-owned utilities (IOUs). The following is the guidance on the continued implementation of this program.

SCE shall revise the existing contract with the Statewide Marketing, Education and Outreach (ME&O) vendor DDB San Francisco (ME&O vendor) to increase the year two budget to $22 million. The year one budget was $12 million, but an additional $10 million was allocated by the California State Legislature through the General Fund in Fiscal Year 2021-22[1] and implemented through a separate contract in 2021. SCE shall also revise the existing contract with the ME&O vendor to extend the paid Flex Alert Media campaign through December 31, 2023, at the same budget of $22 million per year. If for some reason additional allocation is provided for fiscal year 2022 or 2023, SCE shall amend the program to incorporate that additional funding.

SCE shall execute a contract with the ME&O vendor within 60 days of the effective date of this decision to allow for adequate program implementation for the 2022 summer months.

SCE shall coordinate with Energy Division staff to receive direction on the scope of the amended contract and budget during the implementation and administration of the contract. The contract shall terminate on December 31, 2023, unless the contract is extended in a future demand response proceeding as discussed below.

[1] The language in the state budget states “Pursuant to CPUC Decision 21-03-056, the Commission or its delegee may award or designate follow-on funding in the amount of $10,000,000 to the Flex Alert program contemplated in the decision. When used for contracts, awards provided using this authority are exempt from Public Contract Code, Government Code, Department of General Services, and any other normally applicable requirements for awarding, advertising, or amending contracts.”

The Flex Alert campaign shall include marketing messaging and materials for the IOU Residential Emergency Load Reduction Program (ELRP) modifications adopted in this decision. To support the Residential ELRP pilot, the Flex Alert campaign should activate messaging for Day Ahead Flex Alerts, as well as Day Ahead Grid Alerts (i.e., the "Alert" stage of CAISO's Alerts, Warning, Emergency signal). PG&E, SCE, and SDG&E (together, the IOUs) shall fund the paid-media Flex Alert campaign for 2022 and 2023 with funds collected from all benefitting customers (i.e., bundled IOU, community choice aggregator (CCA), and Direct Access customers) using Public Purpose Program (PPP) balancing accounts. Each IOU will collect its share of the authorized Flex Alert campaign PPP funds from all benefitting customers in its service territory.

This decision authorizes a budget of $22 million per year, for 2022 and 2023, to support the Statewide Flex Alert Paid Media campaign. The decision also authorizes IOUs up to 3% of the annual Flex Alert budget to cover IOU administration costs. If the Commission and stakeholders have an interest in considering an extension of paid Flex Alert marketing after December 31, 2023, then the IOUs shall request, as needed, continuation of funding for the Statewide Flex Alert Paid Media Campaign to support the ELRP in the IOU Demand Response Portfolio Applications that are expected to be filed by the IOUs at the CPUC in May 2022.

Consistent with D.21-03-056, SCE, PG&E, and SDG&E shall collect the authorized funds for the statewide paid-media Flex Alert campaign from all customers in their service territories (i.e., bundled customers and customers of CCAs and customers of Direct Access) based on each IOU's portion of the CPUC jurisdictional share of CAISO peak load: 45% for SCE, 45% for PG&E, and 10% for SDG&E.

The Flex Alert modifications in this decision supersede those previously adopted in D.21-03-056.

2. Modifications to IOU Demand Response Programs

Cost-Effectiveness

As directed in D.21-03-056, the use of our traditional cost-effectiveness tools is waived for all demand response proposals adopted in this decision for years 2022 and 2023, under certain conditions. Regarding changes to existing demand response programs adopted in this decision, the IOUs have proposed to use their existing demand response budgets to fund many of those changes, which will help mitigate potential impacts to ratepayers. Any changes that require new incremental funding must be tracked in the memorandum accounts authorized in D.21-03-056, and requests for cost recovery will undergo reasonableness review.

Cost Recovery

As directed in D.21-03-056, PG&E, SCE, and SDG&E shall continue to utilize unspent funds from their existing demand response budgets adopted in D.17-12-003, to the extent existing funds are available.

To the extent that any tariff amendments are necessary to effectuate the demand response program changes ordered in this decision, those changes should be documented in a Tier 1 Advice Letter, as well as the process for transferring balances within the IOU's Demand Response Programs Balancing Account and Base Revenue Requirement Balancing Account for this purpose.

Modifications to Demand Response Programs of All IOUs

Procurement of Demand Response Resources from Third-Party Demand Response Providers

The IOUs shall procure Resource Adequacy capacity from eligible third-party demand response providers (DRPs) for 2022 and 2023 deliveries through bilateral contracts. The procured demand response capacity shall count toward the overall megawatt (MW) targets established for each IOU in this decision and must be available at peak and net peak. Because these procured resources are incremental to IOUs' and all load serving entities' (LSEs') 15% planning reserve margin, these resources would not be applied to any LSEs' Maximum Cumulative Capacity bucket cap calculation.

The third-party demand response resources procured by the IOUs shall be comprised of new resources incremental to all existing DR resources already committed to any LSE. The procured DR capacity shall be integrated into the CAISO markets as economic demand response (under a Proxy Demand Resource product) and must abide by all resource adequacy and CAISO rules. For the purposes of this emergency related procurement only, the DRPs are not required to have completed the Load Impact Protocol process for the demand response resources procured by the IOUs per above order. The procurements shall be informed by the DRPs' past performance.

The IOUs shall include performance requirements in their purchase agreements with the DRPs. To standardize payment/penalty requirements in these contracts, the IOUs shall adopt the capacity payment and penalty structure from PG&E's Capacity Bidding Program (CBP). The CBP payment and penalty structure will govern the contract payment framework. The capacity price of the contracts will be established by the procurement process. The IOUs shall submit bilateral contracts to the Commission through Tier 1 Advice Letters which is consistent with the process ordered in this decision for other procurement.

Auto Demand Response Customized Incentives

The IOUs are authorized to pay upfront 100% of the eligible incentives for a custom Auto Demand Response project on the condition that the customer's enrollment commitment to participate in an eligible demand response program is extended from three years to five years. This modification is effective for 2022 and 2023 only. The Auto DR eligibility criteria for DR programs remain unchanged.

Capacity Bidding Program

The alternative baseline adjustment option allowed by CAISO and already authorized for use in IOU Capacity Bidding Programs and the Demand Response Auction Mechanism in D. 21-03-056 can be used for calculating capacity performance in their respective Capacity Bidding Programs and the Demand Response Auction Mechanism.

Modifications to PG&E's Demand Response Programs, Pilots, and Related Support Programs

1. PG&E's proposal to implement a price bid cap of $650/MWh for its Capacity Bidding Elect and Elect+ programs for the years 2022 and 2023 is approved.

    PG&E's proposal to increase the current Base Interruptible Program (BIP) compensation level by $1/kW for the months of May through October for the years 2022 and 2023, is approved.

PG&E SEASONAL INCENTIVE FOR BIP

Line No.	Potential Load Reduction	Current Incentive (Year-Round)	Proposed Incentive (May – October)
1	1 kW to 500 kW	$9.50/kW	$10.50/kW
2	501 kW to 1,000 kW	$10.00/kW	$11.00/kW
3	1,001 kW and greater	$10.50/kW	$11.50/kW

2. For the Base Interruptible Program compensation level increase, PG&E is authorized to update its tariff to recoup the annual $1 million to $3 million in costs associated with this increase that it is unable to cover in 2022 through the budget of its current 2018-2022 funding cycle, as well as for 2023 costs.

3. PG&E's proposal to create and manage a new out-of-market residential smart thermostat control pilot program is approved for 2022 and 2023. PG&E is authorized to spend an incremental $17.5 million in incentives, administration, and marketing in 2022 and 2023 for this pilot as well as existing identified funding. For the program to continue beyond 2023, this program must be market integrated (as supply-side DR).

4. PG&E is authorized to replace one-way thermostat control technology with newer two-way devices (including switches and thermostats) in 2022 and 2023 in its SmartAC program. PG&E is authorized an incremental $7 million in funding in 2022 and 2023 for administration, marketing, and retention incentives for this device exchange.

5. PG&E's proposal to make Information Technology system enhancements to bolster its "Share My Data" platform by improving scalability and performance is approved and cost recovery of $1.2 million in incremental funds is approved.

Modifications to SCE's Demand Response Programs, Pilots, and Related Support Programs

6. Non-residential customers enrolled in SCE's Summer Discount Program (SDP) are permitted to dual participate in ELRP under the customer subgroup "A.1. Non-Residential, Non-DR Customers," and are not subject to the Minimum Size Threshold of subgroup A.1.

7. SCE's proposal to reinstate the pre-cooling strategy where applicable in its Smart Energy Program (SEP) is approved.

8. SCE's proposal to increase the ME&O budget for its SEP by $1.27 million in 2022, and $980,000 in 2023, to reach a broader audience through targeted marketing channels and leveraging marketing automation technology to improve ME&O effectiveness is approved. SCE is authorized to recover from the memorandum accounts authorized in D. 21-03-056 additional costs that occur in SEP due to the hot climate zone thermostat incentive program.

9. To address CAISO tariff changes stemming from CAISO's Summer Reliability enhancements for reliability demand response resources (RDRR), SCE's proposal to modify effective immediately its Reliability Program Event Parameters, so that 1) the Base Interruptible Program (BIP) and Agricultural Program-Interruptible (AP-I) parameters match, and 2) the parameters for the SDP and SEP match is approved. Modifications to SDG&E's Demand Response Programs, Pilots, and Related Support Programs

Modifications to SDG&E's Demand Response Programs, Pilots, and Related Support Programs

10. SDG&E is authorized to continue in 2022 its Capacity Bidding Program residential pilot approved in D.21-03-056.

11. SDG&E is authorized to create an enhanced Capacity Bidding Program-Commercial Elect option with three bid price tiers and increased capacity incentives as proposed by SDG&E. $1.6 million is authorized for this program for 2023, as well as a $51,000 incremental marketing budget.

3. Dynamic Rate Pilots

A. Valley Clean Energy & PG&E Pilot for Agricultural Pumping

PG&E is directed to collaborate with Valley Clean Energy (VCE) in administering and evaluating a dynamic transactive pilot rate for agricultural pumping loads in VCE's territory with the attributes described in this section. The design and execution of this pilot is intended to be modeled on the concepts and technologies implemented in the CEC EPIC-funded pilots involving dynamic rates: EPC-15-054 and EPC-16-045. This pilot shall be administered under PG&E's DR *Emerging Technologies* program authorized in D.17-12-003 with incremental funding described below.

The section addresses the following critical pilot proposal design elements:

- Program Parameters
- Pilot Duration
- Rate Design
- Billing
- Pilot Evaluation
- Pilot Funds
- Advice Letters

Program Parameters

VCE will enroll agricultural pumping load service points from their customer base with aggregated peak load up to 5 MW. VCE may engage service providers for pump automation and energy management services to equip the pumps with the capability to automatically optimize the pump operation in response to a dynamic rate to achieve bill savings.

Load reduction capacity resulting from this pilot will be excluded from the Resource Adequacy (RA) / California Energy Commission (CEC) peak forecast framework.

Pilot Duration

The pilot is authorized for three years (2022-2024), starting no later than May 1, 2022, and may be extended and/or expanded after the initial period pending approval by the CPUC.

Proposal for expansion and/or extension of the pilot, or conversion of the pilot to an optional rate may be considered in a future General Rate Case or other relevant future proceedings.

Rate Design

The pilot rate design will incorporate the ideas in the 6-step Distributed Energy Resource (DER) & Demand Flexibility roadmap described by Energy Division Staff at the May 25, 2021, workshop on Advance DER and Demand Flexibility Management.[2]

For the generation components of the service by VCE, (1) energy costs will be based on the CAISO wholesale market prices, and (2) generation capacity and flexible capacity costs will be recovered on an hourly basis using the scarcity pricing concept: more fixed costs are recovered when system utilization is higher relative to the system capacity limit.

For the delivery component of the service by PG&E, (1) line losses will be recovered through volumetric rates, which could be time dependent, and (2) distribution capacity costs will also be recovered on an hourly basis using the scarcity pricing concept in lieu of monthly or annual demand charges.

The capacity cost recovery functions (hourly price vs. system utilization) for all components (generation capacity, flexible capacity, and distribution capacity) will be calibrated to fully recover annual VCE generation costs and PG&E delivery costs. Other costs, including billing, metering, access, public purpose, and transmission costs may either be recovered through the existing rate structures or through a monthly subscription charge.

VCE, in consultation with PG&E, may engage a service provider with a suitable IT platform to automate the creation of dynamic hourly prices for the generation and delivery components and present the composite dynamic hourly prices via an internet-based pathway to be accessed by customers and the automated pumps.

Billing

To avoid the need to integrate the pilot rate tariff with PG&E's billing systems, VCE will use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot rate. Participants will continue to pay their current VCE bill under the otherwise applicable tariff and will also receive a shadow bill, which they will not pay. The shadow bill will illustrate a customer's potential savings under the dynamic pilot rate. Participants will receive payments from VCE for their pilot rate savings on either a monthly or annual basis.

PG&E will credit any savings realized by the customers with respect to the delivery component of the pilot rate in the customers' shadow bills. PG&E is directed to set up a 2-way balancing account to track expenses related to the delivery component of the customer bill savings during the pilot.

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[2] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

PG&E Circuit Utilization Data

PG&E is directed to utilize both historical and real-time, or as frequent as possible, hourly circuit load data from the distribution circuits that service participating customers to calibrate and calculate the distribution capacity cost recovery price function. The circuit load data shall be integrated as data inputs into the pilot's IT platform to generate the delivery component of the dynamic prices.

Pilot Evaluation

PG&E, in coordination with VCE, is directed to contract an independent evaluator to conduct a mid-term and final evaluation of this pilot. The mid-term evaluation report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025. The evaluations should include the following elements:

1. The response of agricultural loads to prices, including the response to non-binding week ahead price projections. This should evaluate the efficacy of the pilot tariff in shifting agricultural loads enrolled in the program from peak to off-peak periods and should be compared to other VCE agricultural loads.
2. In the case that VCE incorporates binding forecast projections, the evaluation should also include an assessment of this element.
3. The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff.
4. An evaluation of the recovery of generation and resource adequacy costs for customers on the pilot tariff. This evaluation should assess the impact of any under collection of generation and resource adequacy revenues against the impact of the shifted participant loads on marginal generation and resource adequacy costs, and on the avoided cost value, including using the Commissions' Avoided Cost Calculator, where appropriate.
5. An evaluation of the recovery of delivery costs for customers on the pilot tariff. This evaluation should assess the impact of any under-collection of delivery revenues against the impact of the shifted participant loads on marginal delivery costs, and on the avoided cost value, including using the Commissions' Avoided Cost Calculator, where appropriate.

The evaluations of this pilot should be included in any future PG&E evaluations of the potential of agricultural load responsiveness to dynamic pricing.

Pilot Funds

PG&E is authorized a budget of up to $3.25 million for the administration and execution of the 3-year pilot to be used in the manner specified in the table below.

Expense Type	Amount ($)
Integration and automation* of pumping loads with the pilot price signal	$1,000,000
Vendor fees, Systems & Technology	$1,500,000
Program Administration, including Billing, and Evaluation	$750,000

*For pump integration and automation, in lieu of Auto DR funds, customers could be funded up to $200 per kW of shiftable load as a one-time payment with a minimum three-year participation requirement, or for the duration of the pilot if it is extended up to a maximum of five years.

VCE shall be primarily responsible for the recruitment, integration, and automation of the pumping loads. PG&E shall coordinate with VCE to fund customer integration and automation expenses.

Advice Letters

VCE (in coordination PG&E) will submit a Tier 2 Advice Letter no later than 30 days after this decision that includes, but is not limited to, the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, (5) pilot tariff design, and (6) details of how circuit and system data will be used to calibrate and calculate tariff price curves.

PG&E (in coordination with VCE) is directed to submit a Tier 2 Advice Letter no later than 60 days after this decision that includes, but in not limited to, the following elements: (1) details of how circuit utilization data from the distribution circuits that serve VCE customers will be used to calibrate and calculate the delivery component of the dynamic prices, (2) details of how the circuit utilization data will be integrated with the pilot IT platform, and (3) the administration and evaluation budgets for this pilot.

B. SCE Pilot for All Customers and End Uses

SCE is authorized to conduct a demonstration pilot of the TeMix proposed "Pilot UNIDE Program" to "conduct comprehensive studies that fully assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts." A budget of $2.5 million for "administration, systems, metering, etc." is approved to support this demonstration pilot for three years (2022 to 2024). The pilot shall be administered under SCE's DR *Emerging Markets and Technologies* program authorized in D.17-12-003.

The section addresses the following critical pilot proposal design elements:

- Program Parameters
- Pilot Duration
- Billing
- Pilot Evaluation
- Advice Letters

Program Parameters

SCE is encouraged to enroll residential, commercial, and industrial customer with smart enabling price-responsive end-uses such as electric vehicle charging, behind-the-meter batteries, and controllable loads.

Load reduction capacity resulting from this pilot will be excluded from the Resource Adequacy (RA) / California Energy Commission (CEC) peak forecast framework.

Pilot Duration

The pilot is authorized for three years (2022-2024), starting no later than May 1, 2022, and may be extended and/or expanded after the initial period pending approval by the CPUC.

Proposal for expansion and/or extension of the pilot, or conversion of the pilot to an optional rate may be considered in a future General Rate Case or other relevant future proceedings.

Billing

To reduce the time required to integrate the pilot rate tariff with SCE's billing systems, SCE is encouraged to use a "shadow bill" approach to provide participants compensation for any load shift by the customer's equipment in response to the pilot prices. In such an approach, participants will continue to pay their current SCE bill under the otherwise applicable tariff and will also receive a shadow pilot bill, which they will not pay. The shadow bill illustrates a customer's potential savings under the pilot rate. Participants will receive payments from SCE for their pilot rate savings on either a monthly or annual basis.

Pilot Evaluation

SCE is directed to conduct a mid-term and final evaluation of this pilot to "assess the costs and benefits of real-time rates, including required infrastructure, manufacturer interest, and customer impacts." The mid-term report shall be released no later than December 31, 2023, and a final evaluation shall be released no later than March 1, 2025. The evaluations should include, but not be limited to, the following elements:

1. An evaluation of load responsiveness. SCE should evaluate the efficacy of the pilot tariff in shifting loads enrolled in the program

from peak to off-peak periods and should be compared to non-participant loads;

2. The monthly bill impacts of the pilot dynamic rate in comparison to a customer's otherwise applicable tariff; and

An evaluation of the cost recovery which assess the impact of any under-collection of revenues associated with the pilot similar to the evaluation required of the VCE dynamic rate pilot.

Advice Letters

SCE will submit a Tier 2 Advice Letter no later than 30 days after this decision that includes, but is not limited to, the following elements: (1) pilot scope, (2) pilot partners, (3) shadow bill implementation, (4) pilot dates, and (5) pilot tariff design.

4. Smart Thermostats and Integrated Demand-Side Management (IDSM) Program Development

Targeted Summer Reliability Smart Thermostat Program

This decision authorizes a budget of up to $22.5 million in technology incentives ($75 per measure) to develop a limited, two-year Residential Smart Communicating Thermostat (SCT) program for 2022-23 to incentivize the installation of up to 300,000 SCT in hot climate zones (Climate Zones 9, 10, 11, 12, 13, 14, and 15). This program will be run statewide within each IOU's service territory, and the IOUs may request up to an additional 10% of each IOU's proportional share of the technology incentive budget for administrative costs. Fifty percent of the technology incentive budget, or up to $11.25 million, will be available to third-party DRPs to provide rebates through third-party demand response programs. Third-party DRPs should have competitively equal access to the rebates as the IOUs. This program will require customer pre-enrollment in a market integrated supply-side Demand Response program. Eligible market integrated programs are Demand Response Auction Mechanism, Smart Energy Program, Capacity Bidding Program-Residential, and AC Saver.

The technology incentive amount will be up to $75, limited to the full cost of the SCT. Prior to incentive payment, the IOUs must verify installation of an eligible thermostat and enrollment in an eligible IOU or third-party program. Each IOU must justify the amount of administrative budget that will be required to administer the program.

Within 15 days of the effective date of this Decision, the IOUs shall meet and confer with the third-party DRPs to discuss the process for rebate awards, and installation and enrollment verification. Within 45 days of the effective date of this Decision, the IOUs shall jointly file a Tier 2 advice letter that reflects a consensus across third-party DRPs and IOUs on these issues. This advice letter will include the following:

- Program design and budget;
- How funds and administration of program will be split between IOUs;
- Amount of admin budget up to 10% of proportional share of the technology incentive budget each IOU will need to administer the budget;
- Specify if balancing or memorandum accounts will need to be established to track program expenditures;
- Goal for number of customers reached, by when, estimated MW demand savings;
- Identification of qualifying SCT for incentive;
- Process for providing an incentive to both utility and third-party customers;
- Which Demand Response programs a customer can enroll in to be eligible for the product incentive, and how that enrollment occurs before the customer is rebated;

- Implementation rules such as: whether proof of purchase is needed for reimbursement, If customers with existing eligible thermostats are eligible if not already enrolled in a DR program, number of thermostats per account, disqualification of customers with free thermostats.
- Process for identifying customers that qualify for the Energy Savings Assistance (ESA) or California Alternate Rates for Energy (CARE) programs.

Smart Thermostat program for Income-Qualified Customers

ESA eligible customers will continue to be eligible to receive no-cost, direct install smart thermostats through ESA for all climate zones. This is consistent with current policy detailed in the Statewide ESA Program Policy and Procedures Manual per D.16-11-022 and reaffirmed in D.21-06-015. The IOUs and third-party DRPs participating in the Targeted Summer Reliability SCT Program[3] will be required to verify customer eligibility for the ESA or CARE programs, and if eligible, provide the customer with information about the IOUs' ESA programs. The customer may decide to obtain the SCT through the ESA program, or through the Targeted Summer Reliability SCT Program. If the customer is receiving the SCT through the Targeted Summer Reliability program, they must pre-enroll in a market integrated supply-side Demand Response program, and can still participate in the ESA program for a potentially fuller suite of energy efficiency treatments at no cost. If the customer chooses to participate in the ESA program, the IOUs and their ESA contractors, during their in-person assessment and installation, shall promote, but will not require, enrollment in a market-integrated supply-side demand response program.

Administration of Existing IDSM Program Budget

Limited Integration EE-DR program guidance, as stated in D.18-05-041, is updated to allow IOUs to implement limited integration EE-DR programs, using remining budget previously authorized through D.18-05-041, without a third-party entity designing or implementing the program. The IOUs shall jointly file a Tier 2 advice letter within 90 days specifying program implementation details including:

- Remaining budget to be used authorized through D.18-05-041.
- How the remaining budget will be allocated among the IOUs to run their limited integration programs.
- Program implementation plans and design, including information on how they comply with requirements outlined in D.18-05-041.

(END OF ATTACHMENT 1)

[3] The Targeted Summer Reliability SCT Program is the smart thermostat program adopted in this decision.

Attachment 2
Emergency Load Reduction Program (ELRP)

This Attachment has been copied from Phase I Decision, D.21-03-056. The Attachment later received Corrections from D.21-06-027. This document incorporates the corrections from D.21-03-056 and shows all new changes as hard coded text.

Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) are each directed to administer the Emergency Load Reduction Program (ELRP) pilot as described in the following sections.

1. Pilot Program Duration

ELRP duration will be five years (2021-2025), with years 2023-2025 subject to review and revision in the Demand Response (DR) Applications proceeding expected to be initiated May 2022.

ELRP design aspects that are subject to review and revision include minimizing the use of diesel backup generators where there are safe, cost-effective, and feasible alternatives; consideration of local air pollution impacts on disadvantaged communities; and other modifications to make the program more effective and consistent with the state's decarbonization goals. To this end, PG&E, SCE, and SDG&E should collect data on backup generator participation in ELRP, including as location, type of fuel used, minimum notification time required to dispatch the generator, and the capacity of the generator, for years 2021 and 2022.

2. Out of Market Framework

ELRP load reduction capacity will be excluded from the Resource Adequacy (RA) / California Energy Commission (CEC) peak forecast framework with no CAISO market obligations.

3. Program Parameters

- Program availability: May – October; seven days a week; 4 pm – 9 pm
- Event duration: 1-hour minimum; 5-hour maximum
- Annual dispatch limit: Up to 60 hours
- Consecutive day dispatches: No constraints

As discussed below, the program parameters for Residential ELRP may differ.

4. Eligible Customers

Eligible participants for ELRP are divided into two groups with several subgroups:

- Group A: Customers and aggregators not participating in Demand Response (DR) programs
  - A.1. Non-Residential Customers
  - A.2. Non-Residential Aggregators
  - A.3. Rule 21 Exporting Distributed Energy Resources (DERs)
  - A.4. Virtual Power Plants (VPP) Aggregators
  - A.5. Vehicle-Grid-Integration (VGI) Aggregators
  - A.6. Residential Customers

- Group B: DR providers participating in market-integrated supply-side Demand Response (DR) programs
  - B.1. Third-party DR Providers (DRPs)
  - B.2. IOU Capacity Bidding Programs (CBPs)

At any time, a customer can participate in ELRP via either Group A or Group B, but not both groups at the same time. At any time, a Group A customer can participate in ELRP via only one sub-group under Group A.

Eligibility criteria for each group are defined below.

GROUP A ELIGIBILITY: Customers and aggregators not participating in Demand Response (DR) programs.

At the time of enrollment, or at designated times during the ELRP pilot, Group A participants, except residential customers enrolled in ELRP sub-group A.6 Residential customers described below, will nominate an estimated target load reduction quantity to be achieved during an ELRP event. Participation during an ELRP event is entirely voluntary, and no financial penalties will result from not meeting or exceeding the nominated target load reduction during the event.

If a customer qualifies for the ELRP under both sub-groups A.1. and A.3. criteria described below, the customer will make an election for participating in the ELRP as part of one or the other sub-group at the time of enrollment, or at designated times during the ELRP pilot.

A.1. Non-Residential Customers Eligibility

Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:

- Customer meets the “Minimum Size Threshold” specified further below, and
- Customer is not simultaneously enrolled in another supply-side DR program offered by an IOU, third-party demand response provider (DRP), or community choice aggregator (CCA), with the exception that dual enrollment in an IOU’s Base Interruptible Program (BIP) or SCE’s Agricultural and Pumping Interruptible program is permitted.

The Minimum Size Threshold parameter for each IOU is as follows:

- For PG&E, the customer must be able to reduce load by a minimum one kilowatt (kW) during an ELRP event.
- For SCE, the non-residential service account must have a peak demand of greater than or equal to 100 kW with an SCE approved interval meter.
- For SDG&E, the customer agrees to drop a minimum of 50 kW during an ELRP event.

A.2. Non-Residential Aggregators Eligibility

BIP aggregators are eligible to participate in ELRP. If a BIP aggregator chooses not to participate, its customers may independently participate in ELRP under A.1, subject to the applicable criteria and requirements.

For SCE, participating BIP aggregators may add and nominate only non-residential customers eligible under A.1. in their ELRP portfolio.

Non-BIP aggregators with aggregated bundled or unbundled non-residential customer resources meeting the following criteria are eligible to participate in ELRP:

- The aggregated resource is not simultaneously enrolled in a supply-side DR program offered by an IOU, third-party DRP, or CCA, and
- Customers participating in the aggregation meet the eligibility criteria under A.1 (except the Minimum Size Threshold requirement does not apply), and
- The aggregated resource capacity meets or exceeds Minimum the Aggregation Size Threshold.

If a non-BIP aggregator of non-residential customers chooses not to participate, its customers may independently participate in ELRP under sub-group A.1 Non-Residential customers subject to the applicable criteria and requirements.

The IOUs are authorized to dispatch the aggregated resources offered by the non-BIP aggregators for at least the Minimum Aggregation Dispatch Hours. In addition to the Group A triggers defined below, the IOUs may exercise discretion to dispatch the non-BIP aggregation in response to other forecasted or anticipated grid stress conditions, such as, high locational marginal prices in the CAISO markets, extreme heat waves, etc., to achieve the Minimum Dispatch Hours. The IOUs may negotiate agreements with the non-BIP aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation. Each IOU shall strive to develop a standardized agreement to implement a uniform process to simplify implementation and ensure similar treatment across different aggregators. The IOUs are encouraged to jointly conduct workshops or a working group process to facilitate consensus building on the terms and conditions of the agreements.

Minimum Aggregation Size Threshold is set at 500 kW. The Minimum Aggregation Dispatch Hours is set at 10 hours per season.

A.3. Rule 21 Exporting DER Eligibility

Bundled and unbundled non-residential customers of an IOU who meet the following criteria are eligible to enroll and participate in ELRP:

- Customer is not simultaneously enrolled in any market-integrated DR program offered by an IOU, third-party DRP, or CCA, and
- Customer possesses a behind-the-meter (BTM) Rule 21-interconnected device (including Prohibited Resources) with an existing Rule 21 export permit, and
- Customer's BTM Rule 21 interconnected device meets the "Minimum Export Threshold" specified further below for at least one hour in compliance with Rule 21 and other applicable regulations and permits during an ELRP event.

NEM customers meeting the above requirements are eligible to participate in ELRP.

The Minimum Export Threshold is set at 25 kW based on the physical interconnected capacity.

A.4. Virtual Power Plant Aggregators Eligibility

An aggregator managing a BTM virtual power plant (VPP) aggregation consisting of storage paired with net energy metering (NEM) solar or stand-alone storage deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers, whose VPP meet the following criteria, is eligible participate in ELRP:

- The VPP or any customer site within the aggregation is not simultaneously enrolled in a market-integrated DR program offered by an IOU, third-party DRP, or CCA, and
- All sites within the VPP aggregation are located within the distribution service area of a single IOU, and
- The aggregated BTM storage capacity of the VPP meets the "Minimum VPP Size Threshold", where the VPP size is determined by summing the Rule 21 interconnected capacity of the individual storage devices comprising the aggregation, and
- Each site within the VPP aggregation has a Rule 21 permit.

The VPP aggregations shall be dispatched by the IOUs for at least the Minimum VPP Dispatch Hours per season. In addition to the Group A triggers defined below, the IOUs may exercise discretion to dispatch the VPP in response to other forecasted or anticipated grid stress conditions, such as, high locational marginal prices in the CAISO markets, extreme heat waves, etc., to achieve the Minimum Dispatch Hours. The IOUs may negotiate agreements with the VPP aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation. Each IOU shall strive to develop a standardized agreement to implement a uniform process to simplify implementation and ensure similar treatment across different aggregators. The IOUs are encouraged to jointly conduct workshops or a working group process to facilitate consensus building on the terms and conditions of the agreements.

The Minimum VPP Size Threshold is set at 500 kW. The Minimum VPP Dispatch Hours is set at 20 hours per season.

A.5. Vehicle-Grid-Integration Aggregators Eligibility

An aggregator managing a Vehicle-Grid-Integration (VGI) aggregation consisting of any combination of electric vehicles and charging stations – including those that are capable of managed one-way charging (V1G) and bi-directional charging and discharging (V2G) deployed with residential (bundled or unbundled) or non-residential (bundled or unbundled) customers that meets the following criteria, is eligible to participate in ELRP:

- The VGI aggregation or any customer site within the aggregation is not simultaneously enrolled in a market-integrated, supply-side DR program offered by an IOU, third-party DRP, or CCA, and
- All sites within the VGI aggregation are located within the distribution service area of a single IOU, and
- The VGI aggregation can contribute Incremental Load Reduction (ILR), as defined below, equal to or greater than the Minimum VGI Aggregation Size Threshold for a minimum of one hour during an ELRP event.

NEM customers with electric vehicles meeting the above requirements are eligible to participate in the VGI aggregation.

In recognition of a nascent market, any direct current (DC) V2G electric vehicle supply equipment (EVSE) that has UL 1741 certification - but not UL 1741 SA certification, any subsequent UL 1741 supplement certification required in Rule 21, or Smart Inverter Working Group-recommended smart inverter functions - may interconnect initially for the purpose of participating in the ELRP, subject to all other Rule 21 interconnection requirements. IOUs may request the termination of this interconnection pathway via Tier 2 AL after the 2024 ELRP season if the market has developed to provide multiple V2G capable EVSEs that meet the full smart inverter certification standards required in Rule 21. Termination of this pathway would not affect previously interconnected EVSE, and they may continue to operate parallel to the grid as per their Interconnection Agreement.

The VGI Aggregation shall be dispatched by the IOUs for at least the Minimum VGI Dispatch Hours. In addition to the Group A triggers defined below, the IOUs may exercise discretion to dispatch the VGI Aggregation in response to other forecasted or anticipated grid stress conditions, such as, high locational marginal prices in the CAISO markets, extreme heat waves, etc., to achieve the Minimum Dispatch Hours. The IOUs may negotiate agreements with the VGI aggregators to clarify other requirements as needed, including potential administration fees, to implement the Minimum Dispatch Hours and related ELRP compensation. Each IOU shall strive to develop a standardized agreement to implement a uniform process to simplify implementation and ensure similar treatment across different aggregators. The IOUs are encouraged to jointly conduct workshops or a working group process to facilitate consensus building on the terms and conditions of the agreements.

The Minimum VGI Aggregation Size Threshold is set at 25 kW. The Minimum VGI Dispatch Hours is set at 30 hours per season.

The IOUs shall implement A.5 participation in the ELRP by May 1, 2022.

A.6. Residential Customer Eligibility

Eligibility

Bundled and unbundled residential customers of an IOU who meet the following criteria are eligible to enroll in ELRP by opting-in to participate:

- The customer is not simultaneously enrolled in another supply-side[4] DR program offered by an IOU, third-party DRP, or CCA; and
- The customer is not served by a CCA which has elected to exclude its customers from participation in ELRP.

Unenrollment

[4] Supply-side programs are integrated into the CAISO market(s).

A customer participating in ELRP is permitted, at any time, to enroll in a supply-side DR program offered by the IOU, third-party DRP, or CCA. The IOU shall arrange to promptly unenroll the customer from ELRP without any action needed on the part of the customer.[5]

Customers can choose to opt-out of ELRP at any time and IOUs shall ensure the process is simple and easy for customers using methods such as a 1-click digital form or an email or text message.

Opt-In Enrollment of Eligible Customers

Eligible customers may opt-in to enroll in an IOU's Residential ELRP pilot. The IOUs shall ensure that the enrollment process is simple and easy for customers using methods such as a 1-click digital form or an email or text message.

Auto-Enrollment of Select Customers

PG&E's proposed Power Saver Rewards Program (Behavioral DR – Option A), with auto-enrollment of "customers who receive PG&E's Home Energy Reports" is approved, as modified herein, as PG&E's Residential ELRP pilot program for the duration of the ELRP pilot, except that Options B & C of PG&E's proposal are not approved.

SCE's proposed Whole Home Savings Pilot, with auto-enrollment of "high usage customers who have opted in to receive transactional emails," is approved, as modified herein, as SCE's Residential ELRP pilot program for the duration of the ELRP pilot, except that SCE proposed dual participation with other supply-side DR programs or SCE's VPP Pilot is not permitted at this time.

SDG&E's "Peak Day" Behavioral DR program, with auto-enrollment of "existing Home Energy Report (HER) customers," is approved, as modified herein, as SDG&E's Residential ELRP pilot program for the duration of the ELRP pilot.

In addition to the IOU-specific auto-enrolled set of select customers specified above, the IOUs shall auto-enroll residential customers on California Alternative Rates for Energy (CARE) and

[5] The IOU in its role as Utility Distribution Company (UDC) tracks a customer's location registration in the CAISO Demand Response Registration System (DRRS). Whenever a customer is entered into the DRRS, the UDC must validate that the customer does not participate in an IOU DR program. If the IOU sees that a CCA or third-party DR provider registers a customer location in the DRRS, the IOU at that time should unenroll the customer from the Residential ELRP pilot. *See* Electric Rule 24 (PG&E and SCE) and 32 (SDG&E).

Family Electric Rate Assistance (FERA) programs, and who meet the above specified eligibility criteria for Residential ELRP (sub-group A.6). Whether through email, phone call, text message, bill insert, or mailer, these customers shall be given an opportunity to opt-in to receive ELRP related messaging or opt-out from ELRP.

Other Program Elements

In their marketing, education, outreach, and event notification efforts focused on auto-enrolled customers as well as customers in DACs, the IOUs shall incorporate the marketing aspect of CEJA's Just Flex Rewards proposal, such as the following:

- ☐ *Accessibility, In-Language*: Marketing shall be done in accessible, in-language communication, when that information is known, whether that be through text, email, or phone messaging. The Disadvantaged Communities Advisory Group may choose if it wishes to evaluate the language of the communications for accessibility and make recommendations to the IOUs.

- ☐ *Specific Outreach for DAC and CARE customers*: Targeted marketing and messaging should be designed for CARE, Energy Savings Assistance (ESA), Family Electric Rate Assistance (FERA) and DAC households. The IOUs shall partner with their ESA contractors and Community Based Organizations to help reach these customers, inform them of their enrollment status, potential compensation rate, and voluntary participation with no penalty.

The IOUs shall establish a process for a CCA to inform the IOU of its election to exclude its customers from ELRP. The CCA shall make its election by January 31 of a new ELRP pilot year.

The IOUs shall collaborate to establish common program parameters, including a minimum dispatch window (which must be at least 2 hours), the start time of the dispatch, marketing that limits customer confusion with state-wide Flex Alert campaign, and state-wide unified branding. The IOUs shall file a Tier 2 Advice Letter within 60 days of issuance of this decision to establish the parameters for its ELRP Residential pilot program and advise the CPUC of the associated costs.

The IOUs shall implement A.6 participation in the ELRP by May 1, 2022.

GROUP B ELIGIBILITY: DR providers participating in market-integrated supply-side Demand Response (DR) programs

At the time of enrollment, or at designated times during the ELRP pilot, Group B participants will list the Proxy Demand Resources (PDRs) that will participate in ELRP and nominate an estimated target load reduction quantity (August) to be achieved during an ELRP event by each participating PDR resource. Participation during an ELRP event is entirely voluntary, and no financial penalties will result from not meeting or exceeding the nominated target load reduction quantity during the event.

B.1. Third-party DR Providers (DRPs) Eligibility

A third-party DRP with a market-integrated proxy demand resource (PDR) is eligible to participate in ELRP.

B.2. IOU Capacity Bidding Programs (CBPs) Eligibility

An IOU's Capacity Bidding Program's PDRs are eligible to participate in ELRP.

5. Program Event Triggers

ELRP will utilize both day-ahead (DA) and day-of (DO) triggers.

Day-Ahead (DA) Trigger

The ELRP DA trigger for Group B resources is activated when a DA Alert, per the "Alert, Warning, Emergency (AWE)" process defined by the CAISO Operating Procedure 4420, is declared by the CAISO. The start time and duration specified in the DA Alert defines the Group B ELRP event window.

Following a DA Alert declaration by the CAISO, the IOUs will exercise discretion to activate the DA trigger for Group A participants, excluding Residential ELRP customers (sub-group A.6), either selectively staggered over time or all ~~DA~~ participants at the same time. The start time and duration specified by the IOU defines the ELRP event window for the Group A participants called by the IOU.

In addition, the IOUs shall dispatch the Residential ELRP customers (sub-group A.6) in response to a Day-Ahead CAISO Flex Alert declaration or CAISO Day-Ahead Grid Alert, i.e., the “Alert” stage of the “Alert, Warning, Emergency” process defined by the CAISO Operating Procedure 4420.

Day-Of (DO) Trigger

Following any AWE declaration by the CAISO, the IOUs will exercise discretion to activate the DO trigger for Group A participants, either selectively staggered over time or all participants at the same time. The start time and duration specified by the IOU defines the ELRP event window for the Group A participants called by the IOU for the DO trigger.

The ELRP DO trigger for Group B resources is activated when a Warning or Emergency, per the AWE process, is declared by the CAISO. The start time and duration specified in the CAISO’s declaration defines the Group B ELRP event window.

Other Trigger Related Guidelines

An ELRP event cannot be triggered by an IOU for a localized transmission or distribution emergency.

For coordination among and guidance to the IOUs in the exercise of discretion for Group A trigger activation, the IOUs shall continue to work with the “Joint ELRP Operations Board,” consisting of representatives from each IOU’s grid operations group and an invited representative from the CAISO’s grid operations group. Following an AWE declaration by the CAISO, the Board will periodically assess the current and forecasted grid conditions and provide guidance on target load reductions to be sought by the IOUs from Group A participants.

The IOUs are directed to coordinate with the CAISO in providing timely information on the status and expected load reduction under ELRP from Group A.

Future Alert Warning Event (AWE) Declarations

In the future, when the CAISO completes the transition from the current AWE process to the North American Electric Reliability Corporation (NERC) Energy Emergency Alert (EEA) standards, then the AWE declarations shall be replaced by the equivalent CAISO issued day-ahead EEA level notices in the above guidelines, per the following table:

Table. Alert Warning Event Levels

AWE Levels	NERC EEA Levels	Comments
Restricted Maintenance Operations		Issued in real time or in advance
Transmission Emergency		Issued in real time
Notifications of forecasted reserve deficiencies		
Alert	EEA-1	Issued in advance – day ahead by 1500
Warning	EEA-1	Issued in real time
Warning – triggering DR programs	EEA-2	Issued in real time
Stage 1	EEA-2	Issued in real time
Stage 2	EEA-3	Issued in real time
Stage 3	EEA-3	Issued in real time

6. Compensation

Incremental Load Reduction (ILR) is defined as the load reduction achieved during an ELRP event incremental to the non-event applicable baseline and any other existing commitment. Only ILR is eligible for compensation under ELRP.

Any load reduction technology may be used during an ELRP event to achieve ILR. Prohibited resources, except those operated by non-residential customers located in Disadvantaged Communities, may be used when permitted by a Governor's Executive Order and in compliance with Rule 21 and other applicable regulations and permits, during an ELRP event to achieve ILR, including during the overlapping period with an independently triggered event in a dual-enrolled DR program, but only for achieving load reduction incremental to any other existing commitment (e.g., under a dual-enrolled DR program). The existing Prohibited Resources policy still applies to IOU and third-party managed DR programs, excluding ELRP.

General ELRP compensation parameters for all customers include the following:

- After-the-fact pay-for-performance will be made at a prefixed energy-only ELRP Compensation Rate applied to ILR.
- There are no "capacity-like" payments.
- There are no penalties for non- or under-performance.

The ELRP Compensation Rate for Group A is set at $2 / kilowatt-hour (kWh) (or $2000 / megawatt-hour (MWh)).

The ELRP Compensation Rate for Group B PDRs is also set at $2 / kWh (or $2000 / MWh).

GROUP A COMPENSATION

For Group A eligible participants, the compensation for load reduction delivered during an ELRP event is determined by calculating the product of ILR and ELRP Compensation Rate.

A.1. Non-Residential Customer Compensation

Baseline

The ELRP baseline will be constructed by all IOUs according to the method described below.

1. A customer's Adjusted Energy Baseline (AEB) for an ELRP event is calculated by multiplying the energy baseline (EB) by the optional day-off (DO) adjustment.
2. The EB will be calculated on an hourly basis using the average of either 1) the previous 10 calendar days, or 2) the previous 10 similar days.
3. The days selected in step 2 above shall exclude days when a) the customer was subject to an ELRP event or an event in a dual-enrolled DR program, or b) there was a grid outage during similar hours.
4. The DO adjustment value shall be either 1) not less than 1.00 or greater than 1.40, or 2) not less than 0.60 or greater than 1.40. The DO adjustment is a ratio of (a) the average load of the first three hours of the four hours prior to the event to (b) the average load of the same hours from the last 10 days selected in accordance with step 2 above.

Special Considerations

1. In the case of overlapping BIP and ELRP events, only the incremental reduction below the customer's pre-committed firm service level (FSL) is counted in ILR.

   a. Load reduction by dual-enrolled BIP customers during an ELRP event outside of a BIP event is excluded from ILR (and not eligible for ELRP compensation).
   b. Load reduction by dual-enrolled BIP customers during an ELRP event on a day with no BIP event is excluded from ILR (and not eligible for ELRP compensation).
2. If the customer has a Rule 21 interconnected device with export capability and permit, the customer may choose to count exported energy in ILR. In that case, the applicable ELRP baseline is modified to account for exported energy during non-event days and count exported energy in ILR.
3. If the customer is currently taking a CPP or real-time pricing (RTP) equivalent tariff, any ILR during overlapping hours between the dynamic rate and the ELRP event is attributed to ELRP.

An IOU may choose to implement the ELRP baseline with only one option for the ten-day selection or one option for the DO adjustment by filing a Tier 1 AL.

A.2. BIP Non-Residential Aggregators Compensation

Same guidelines as A.1 apply.

A.3. Rule 21 Exporting DER Compensation

For a customer on a CPP or RTP equivalent tariff, the ELRP baseline is deemed to be zero and only exported energy is counted in ILR.

For a customer not on a CPP or RTP equivalent tariff, the ELRP baseline defined under A.1 is utilized and modified to account for exported energy during non-event days and exported energy is counted in ILR.

Only during ELRP dispatch hours, a customer with control over multiple electrically contiguous sites is permitted to virtually aggregate the load and generation to fully utilize the sum of the net export allowed by any Rule 21 permit(s) associated with the sites. Two sites are considered electrically contiguous when they have electric service derived from the same utility distribution transformer secondary and there are no devices on the utility distribution system that can interrupt power flow to only one site.

A.4. Virtual Power Plant Aggregators Compensation

The aggregator selected CPUC approved baseline for IOU's CBP is utilized and modified to account for exported energy, to the extent allowed by a site's Rule 21 export permit, during non-event days and count exported energy in ILR.

The above baseline method may be used in conjunction with a meter or a sub-meter embedded within a storage system (such as, an internal sub-meter within the battery inverter) that directly measures the energy flows into/out of the storage device to determine the ILR for the ELRP settlement.

A.5. Vehicle-to-Grid Aggregators Compensation

An EVSE meter, or EVSE sub-meter if the EVSE is taking service through the host site meter, may be used to determine the ILR for ELRP settlement. The EVSE sub-meter must meet applicable standards established by the CPUC when adopted.

Only during IOU dispatched hours, the VGI aggregator is permitted to virtually aggregate separately metered EVSE that have a Rule 21 Interconnection Agreement with other load and generation (if any) at an electrically contiguous host site to allow export from the EVSE to reduce the host site's load and export from such aggregation up to the sum of the net export allowed by any available Rule 21 Interconnection Agreements of the EVSE site and the host site.

Two sites are considered electrically contiguous when they have electric service derived from the same utility distribution transformer secondary and there are no devices on the utility distribution system that can interrupt power flow to only one site.

A.6. Residential Customers Compensation

The IOUs will have the discretion to determine the proper baseline against which incremental load reductions will be calculated and compensated. The IOUs shall evaluate the baseline methodology after the first program year.

GROUP B COMPENSATION

ELRP Baseline for Group B

To construct the ELRP baseline for measuring a Group B PDR's ILR contribution during an ELRP event, the applicable CAISO baseline will be modified to account for the following:

1) Count net exports to the distribution grid by customer locations within the PDR aggregation that comply with Rule 21 and other applicable permits,
2) Exclude prior days with other ELRP events when selecting the set of "non-event, but similar" days when calculating the baseline,
3) Exclude applicable preceding hours with either CAISO market awards or another ELRP event on the day of the ELRP event when calculating the same-day adjustment to the calculated baseline in step 2, and
4) Allow the same day adjustment in step 3 to be no greater than 100%.

ELRP Settlement for Group B

For participation in ELRP under Group B, a DRP must construct a PDR Portfolio consisting of only 1) PDRs with RA assignment or PDRs without RA assignment (but not both) and 2) PDRs limited to the service area of one IOU (thus, a DRP may have up to six PDR portfolios participating in ELRP).

The CAISO settled aggregated load during an ELRP event is modified to count net energy exported to the distribution grid by any customer location within the PDR aggregation.

Following an ELRP event, the DRP's scheduling coordinator is responsible for determining the following:

1. ELRP Event Performance (total load reduction during the ELRP event) of each PDR in the DRP's PDR Portfolio by applying the applicable ELRP modified baseline to the PDR's modified aggregated load settled during the ELRP event.

2. ILR of each PDR by subtracting the CAISO scheduled award quantities, inclusive of day-ahead market (DAM) and real-time market (RTM), from the PDR's ELRP Event Performance. If the total market award for the PDR during the ELRP event is zero, then ILR of the PDR equals the ELRP Event Performance.

3. The ELRP Event Compensation due for each PDR by adding all interval-specific ELRP Compensations across all applicable intervals of the ELRP event, subject to the following:

    a. The interval-specific ELRP Compensation in each applicable interval of the ELRP event is obtained by subtracting 1) any CAISO market payments for any portion of the load reduction counted in the interval-specific ILR and 2) the interval-specific CAISO Opportunistic Revenue (COR), defined below, from 3) the interval-specific Product of the ELRP Compensation Rate and the interval-specific ILR (see illustration below).

If the interval-specific ILR is negative, then the interval-specific ELRP Compensation is set to zero in that interval.

If the interval-specific COR is greater than the interval-specific Product, then the interval-specific ELRP Compensation is set to zero in that interval.

b. The interval-specific COR is the product of the interval-specific Market Eligible Capacity (MEC), defined below based on the interval-specific CAISO Market Event Performance (MEP) determined under the applicable CAISO market baseline, and the interval-specific CAISO Clearing Price Delta (CCPD), defined below (see illustration below).

   i. MEC:

      If the total CAISO scheduled award quantity in an interval is non-zero:

      1. And if the interval-specific MEP is less than or equal to the total CAISO scheduled award quantity in the interval, then the interval-specific MEC is set to zero.

      2. And if the interval-specific MEP is greater than the total CAISO scheduled award quantity in the interval and less than or equal to the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific MEP minus the interval-specific total CAISO scheduled award quantity.

      3. And if the interval-specific MEP is greater than the Qualifying Capacity (QC) of the PDR in that interval, then the interval-specific MEC is equal to the interval-specific QC of the PDR minus the interval-specific total CAISO scheduled award quantity.

If the total CAISO scheduled award quantity in an interval is zero, then the interval-specific MEP in the above cases is set to the interval-specific ILR.

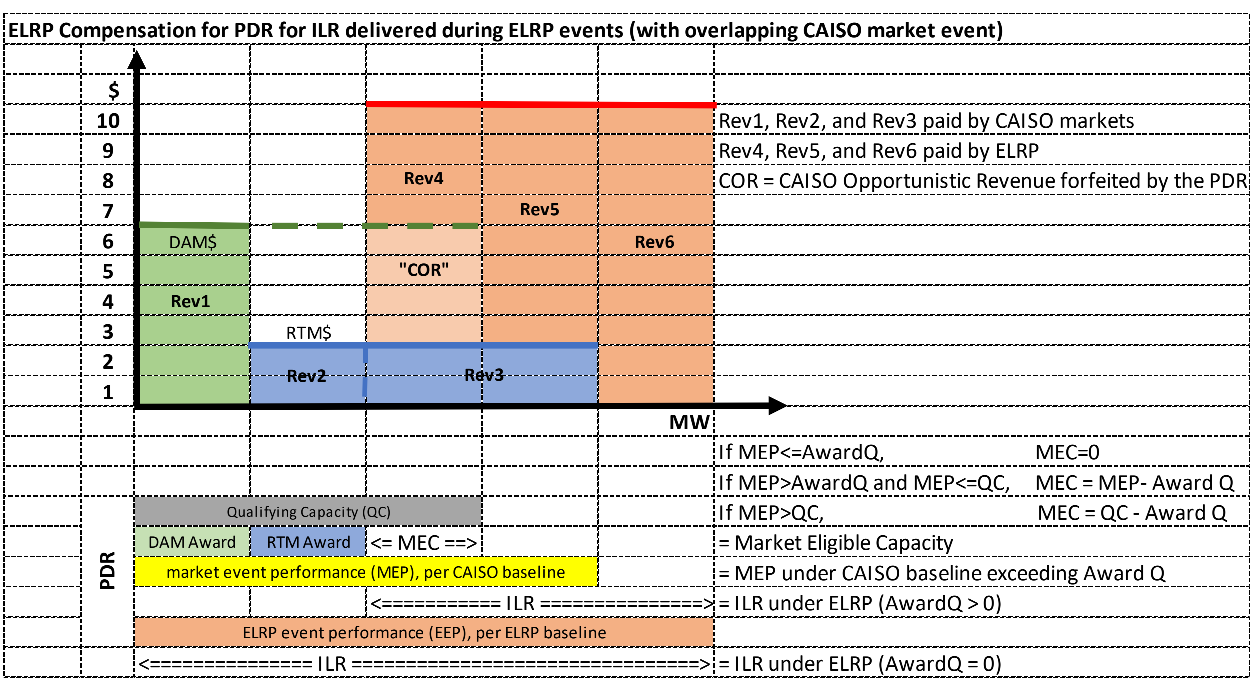
If the PDR has no assigned QC in the above cases, then the QC is replaced by the PDR's "PMin" parameter on record in the CAISO Master File applicable to the interval. Additionally, if the PMin value is less than the total CAISO scheduled award quantity in an interval, then the interval-specific MEC is set to zero.

ii. CAISO Clearing Price Delta (CCPD):

For a PDR participating in the DAM only (that is, "long-start" PDR), the interval-specific CCPD is the DAM clearing price in that interval.

For a PDR participating in the RTM, the interval-specific CCPD is equal to the higher of the DAM or RTM clearing price in that interval minus the lower of the DAM or RTM clearing price in that interval.

4. Portfolio Level Net Event Compensation across all PDRs in the third-party DRP's Portfolio.



To receive ELRP compensation, the third-party DRP shall submit an aggregate invoice for the Cumulative Portfolio Level Net Event Compensation of each PDR Portfolio for May-June-July (First Quarter) period by September 30 and for August-September-October (Second Quarter) by December 31 of the program year. for each of its PDR Portfolio to the applicable IOU's team administering Demand Response Auction Mechanism invoices. The Cumulative Portfolio Level Net Event Compensation of a PDR Portfolio over one Quarter is determined by summing the Portfolio Level Net Event Compensation across all ELRP events in that Quarter.

The invoice shall be accompanied with the supporting data for each event, including but not limited to PDR-specific ELRP Event Performance, ILR, applicable market awards during the event, applicable CAISO market payments for load reductions counted in the ILR, and ELRP Event Compensation. The IOU may audit and verify the invoice as needed. The aggregate invoice amount must be equal to or larger than the ELRP Minimum Invoice Threshold to be eligible for compensation by the IOUs. The IOU shall settle the invoice within 60 days of the invoice date.

The ELRP Minimum Invoice Threshold is set at zero at this time.

7. Other Program Elements

Test Events

The IOUs shall conduct one test event, with two-hour duration, per year for Group A participants.

ELRP Group A.1 and A.3 participants, except for those relying exclusively on prohibited resources, are required to participate in the test events. Use of prohibited resources during a test event is not permitted and will not be compensated. Incremental load reduction (ILR) delivered during an ELRP test event is eligible for ELRP compensation.

ELRP sub-group A.6 Residential customers are exempt from testing requirements.

The IOUs are directed to collaborate with the CAISO and the CEC in the testing process and provide data regarding ELRP response to the CAISO and the CEC to facilitate forecasting.

Advice Letters

Within 60 days of this Decision, the IOUs shall jointly file a Tier 1 AL incorporating the modifications by this Decision ELRP terms and conditions for Group A. Limited deviations to accommodate IOU specific implementations due to IT and billing systems are permitted. The filing shall include the details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification and customer acknowledgment, ILR measurement, and settlement.

Within 60 days of this Decision, the IOUs shall jointly file a Tier 1 AL incorporating the modifications by this Decision ELRP terms and conditions for Group B. Limited deviations to accommodate IOU specific implementations due to IT and billing systems are permitted. The filing shall include the details necessary to implement the ELRP guidelines set forth above and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification, ILR measurement, and settlement and invoicing.

An IOU's Tier 1 AL filing to defer implementation of certain ELRP design elements, where permitted, shall include an explanation for why the delay is necessary or reasonable.

As experienced in ELRP is gained, the IOUs may seek to modify various aspects of ELRP design via an IOU-specific or joint IOU Tier 2 AL as appropriate before or by January 15 of each program year to manage program enrollment, improve program efficiency, increase potential load reduction available to ELRP, improve program value, and reduce program cost. The change request shall be limited to technical aspects of the program design related to program eligibility criteria or requirements (including various minimum size threshold parameters), dual participation between ELRP and another DR program, program trigger(s), minimum dispatch hours, Group A baselines and settlement, and Group B baselines, settlement, and invoicing guidelines. A request to allow a particular dual participation option should be accompanied with an explanation and methodology to demonstrate how the ILR during overlapping event could be attributed uniquely to ELRP participation and avoid double compensation.

8. Balancing Accounts and Cost Recovery

PG&E, SCE, and SDG&E shall continue to use the one-way balancing accounts authorized in D.21-03-056 regarding the development, implementation, and operation of the ELRP pilot program, along with incentives paid under the program.

This ELRP budget reflects projected costs for IOU program administration, including IT, evaluation, measurement, and verification costs, in addition to costs for compensating eligible customers who have contributed load reductions in response to an ELRP event. Customer compensation costs for each IOU assume the ELRP Compensation Rate specified earlier for both Groups A and B, for up to the 60-hour annual limit; however, if no ELRP events are called, customer compensation costs are assumed to be zero.

These balancing accounts shall have the following annual caps for program administration across all ELRP sub-groups, except ELRP sub-group A.6 (Residential customers):

- PG&E $7.3 million,
- SCE $5.7 million, and
- SDG&E $3.0 million.

Additionally, these balancing accounts shall have the following caps for Residential ELRP (sub-group A.6) program administration and marketing, education, and outreach. While these caps are listed by year, the IOUs may shift funds between 2022 and 2023 as needed:

- PG&E:
    - 2022: $9.4 million for administration and $2.5 million for marketing, education, and outreach.
    - 2023: $8.7 million for administration and $2.0 million for marketing, education, and outreach.
- SCE:
    - 2022: $10.0 million for administration and $2.5 million for marketing, education, and outreach.
    - 2023: $9.0 million for administration and $1.6 million for marketing, education, and outreach.
- SDG&E:
    - 2022: $3.3 million for administration and $0.75 million for marketing, education, and outreach.
    - 2023: $3.0 million for administration and $0.5 million for marketing, education, and outreach.

Additionally, these balancing accounts shall have the following annual caps for Incremental Load Reduction compensation across all ELRP sub-groups, including the ELRP sub-group A.6 (Residential customers):

- PG&E $94.0 million,
- SCE $76.6 million, and
- SDG&E $31.1 million.

(End of Attachment 2)

ATTACHMENT 3 – PARTIES

Parties who submitted testimony/reply testimony	Abbreviation
Pacific Gas and Electric Company	PG&E
American Clean Power- California	ACP-CA
Advanced Energy Economy	AEE
Bloom Energy Corporation	N/A
California Independent System Operator Corporation	CAISO
California Community Choice Association	CalCCA
Calpine Corporation	Calpine
California Solar & Storage Association	CALSSA
California Wind Energy Association	CALWEA
Center for Energy Efficiency and Renewable Technologies	CEERT
California Environmental Justice Alliance	CEJA
California Energy Storage Alliance	CESA
California Large Energy Consumers Association	CLECA
Diamond Generating Corporation	N/A
Enchanted Rock, LLC	Enchanted Rock
Ev.Energy Corp	Ev.Energy
Fuel Cell Energy, Inc.	Fuel Cell Energy
Google LLC	Google
Green Power Institute	GPI
Grid Alternatives	N/A
Independent Energy Producers Association	N/A
Joint Demand Response Parties	Joint DR Parties
Joint Parties	Joint Parties
LS Power Development, LLC	LS Power
Marin Clean Energy	MCE
Microgrid Resources Coalition	N/A
Middle River Power LLC	Middle River Power
OhmConnect, Inc.	OhmConnect
Oracle Utilities	Oracle
Protect Our Communities Foundation	PCF
Peninsula Clean Energy	Peninsula Clean Energy
Polaris Energy Services	Polaris
Public Advocates Office	Cal Advocates
Recurve Analytics, Inc.	Recurve
Saavi Energía	N/A

Southern California Edison Company	SCE
San Diego Gas & Electric Company	SDG&E
Solar Energy Industries Association	SEIA
Sierra Club	Sierra Club
California Association of Small and Multi-Jurisdictional Utilities	SMJU
Sunrun, Inc.	Sunrun
TeMix, Inc.	TeMix
The Utility Reform Network	TURN
Union of Concerned Scientists	UCS
Valley Clean Energy	VCE
Vehicle Grid Integration Council	VGIC
Voltus, Inc.	Voltus
Wärtsilä North America, Inc.	Wärtsilä
Western Power Trading Forum	N/A

(End of Attachment 3)

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 14
Page 1 of 1

Has Mr. Alvarez performed any study, besides that in Exhibit B to Alvarez testimony, 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:

No. Appendix B attached to Mr. Alvarez's testimony constitutes his entire analysis projecting the cost to implement a Full PTR program (not a Universal PTR program as Mr. Alvarez clarified in response to DEK-AG-01-011) for Duke Energy Kentucky's electric customers.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 15
Page 1 of 1

Please state if Mr. Alvarez is aware of the Kentucky Public Service Commission (KYPSC) approving either: 1) a non-voluntary, full, universal, or default time of use rate for a utility's residential or small commercial customers; or 2) a non-voluntary, full, universal, or default peak time rebate for a utility's residential or small commercial 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 knows of no such order. However, Mr. Alvarez notes that Big Rivers Electric Corporation's 2020 Integrated Resource Plan (Case No. 2020-00299) identified a potential Full PTR program for which it may seek Commission approval to implement. The consultant who prepared the IRP application in that docket found that a full PTR program would have a TRC of 8.1.[1] The Commission Staff Report in that docket offered no criticism of that potential PTR program.

[1] Case No. 2020-00299, IRP Application Table 4.7 at p. 88.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 16
Page 1 of 1

Is Mr. Alvarez aware if the KYPSC has either: 1) previously rejected a non-voluntary, universal, full, or default 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, universal, full, or default 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 knows of no such Kentucky PSC Order or opinion.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 17
Page 1 of 1

On page 5 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. Does Mr. Alvarez 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:

Yes.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 18
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:

Mr. Alvarez knows of no such deviations.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 19
Page 1 of 1

Do the Kentucky Attorney General and/or Mr. Alvarez agree that the following excerpts from page 9 and 10 of the stipulation and recommendation in Case No. 2016-00152 confirm 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:

Confirmed.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 20
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:

Mr. Alvarez agrees that over payment of load reduction incentives in a PTR program could lead to negative impacts on cost effectiveness scores for the program. However, Mr. Alvarez's analysis of the $0.60/kWh load reduction incentive, as presented in the Table on page 28 and with further details in Appendix B, does not indicate that the $0.60/kWh load reduction incentive represents an over payment, as the analysis indicates benefits in excess of costs to customers overall from a Full PTR program at the specified incentive level.

Further, Mr. Alvarez notes that the level of incentive which constitutes an "over payment" has not yet been determined, and that the ongoing evaluation of the impact of a higher incentive ($1.20/kWh) has not yet been completed.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel As To Objection

QUESTION No. 21
Page 1 of 1

Please confirm whether any representative of the Kentucky Attorney General attended any of the Company's DSM Collaborative meetings during 2019 or 2020 or 2021?

RESPONSE:

Objection, relevancy. The question seeks information irrelevant to the issues DEK presents in the instant docket. Without waiving this objection, the AG notes that this information is in the public record of other dockets, and was thus already available to DEK.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 22
Page 1 of 1

Referring to Alvarez testimony page 9, lines 19 & 20 "a utility like DEK is unlikely to maximize the demand response and energy efficiency value of smart meters absent Commission Orders to do so." Please provide all supporting documents for this statement.

RESPONSE:

For-profit utility incentives such as capital bias (referring to the capital required for generation, transmission, and distribution infrastructure associated with meeting coincident system peak demand) and the throughput incentive (referring to growth in sales volumes between rate cases) are clearly recognized as side effects of the cost-of-service ratemaking model which regulators of for-profit utilities must manage. The cost-of-service ratemaking model is currently employed in Kentucky and all other for-profit utility regulatory jurisdictions in the U.S. but Hawaii. Capital Bias and the Throughput Incentive are both included as part of the "Averch-Johnson Effect", named after the seminal work of H. Averch and L. Johnson, "Behavior of the Firm Under Regulatory Constraint", published in the American Economic Review, Volume 52, pages 1052-1069 (1962). The Averch-Johnson Effect has been cited in numerous research, publications, and presentations sponsored by the National Association of Regulatory Utility Commissioners (NARUC) in the six decades since.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 23
Page 1 of 1

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:

The referenced cost-benefit analysis is presented in the Table on page 28 of Mr. Alvarez's testimony, with additional details provided in Appendix B, and through workpapers filed simultaneously with Mr. Alvarez's testimony, and in response to DEK-AG-01-009. Note that Mr. Alvarez's analysis does not assume automatic eligibility ("universal" PTR).

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objection

QUESTION No. 24
Page 1 of 1

Is the Kentucky Attorney General and/or Mr. Alvarez aware of a Kentucky DSM program that relied on secondary, out of state data inputs or a consultant's "financial projection" for cost-effectiveness analysis instead of relying on actual data from a recent 2-year pilot program run in the service area where the DSM program intends to be launched?

RESPONSE:

Objection. The question mischaracterizes Mr. Alvarez's testimony, and as such assumes facts not in evidence. Additional objection: relevancy, since the premise of the question is patently false. Without waiving these objections, Mr. Alvarez states: Mr. Alvarez notes that his analysis does rely on actual data from the recent 2-year pilot program run in the service area where the DSM program "intends to be launched" [sic] (cited as Exhibit E, "Peak Time Credit Pilot Evaluation", submitted by the Company as part of its Application). Mr. Alvarez's reliance on this "actual data" is clear from Appendix B attached to his testimony, and from workpapers filed simultaneously with Mr. Alvarez's testimony and provided in response to DEK-AG-01-009. Mr. Alvarez is not aware of a Kentucky DSM program that relies on "secondary, out-of-state data inputs or a consultant's "financial projection" for cost-effectiveness analysis."

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 25
Page 1 of 1

Does Mr. Alvarez agree that Duke Energy Kentucky has operated a PTR pilot for over 2 years?

RESPONSE:

Yes.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 26
Page 1 of 1

Do the Kentucky Attorney General and/or Mr. Alvarez agree that Duke Energy Kentucky has met the enrollment target established by the EM&V vendor to obtain statistically significant results from the pilot?

RESPONSE:

Mr. Alvarez agrees.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 27
Page 1 of 1

Does Mr. Alvarez agree that Duke Energy Kentucky has met the enrollment target established by the EM&V vendor to obtain statistically significant results from the pilot?

RESPONSE:

See the response to DEK-AG-01-026.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 28
Page 1 of 1

Does Mr. Alvarez agree that Duke Energy Kentucky sent at least 1 email to all eligible customers who have shared an email address with the Company either in the original pilot group or the summer 2022 incentive test effort?

RESPONSE:

Yes.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 29
Page 1 of 1

Does Mr. Alvarez agree that the total number of customers enrolled, divided by the total number of customers who received emails represents the percentage of customers who enrolled in one of the PTR pilot groups?

RESPONSE:

Yes.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 30
Page 1 of 1

Does Mr. Alvarez agree that the EM&V report in the Company's Appendix E was performed by an independent, qualified vendor?

RESPONSE:

Mr. Alvarez agrees that the vendors and consultants completing the PTR pilot evaluation are qualified to complete such an evaluation. Regarding vendor independence, Mr. Alvarez is uncertain. It is Mr. Alvarez's personal experience that DSM program evaluators are almost always selected and managed by the utilities offering DSM programs. Mr. Alvarez is not certain that such arrangements are consistent with vendor independence.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 31
Page 1 of 1

Have the Kentucky Attorney General and/or Mr. Alvarez performed a study in the Duke Energy Kentucky service area to determine the percentage of smart meter benefits related to EE and demand response?

(a) If yes, please provide all such studies and all supporting papers and calculations.

RESPONSE:

No.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 32
Page 1 of 1

What circumstances would enable a full PTR program to fully maximize the EE and DR benefits of smart meters?

(a) Would personalized power-saving recommendations based on smart-meter data improve customers' ability to benefit from a full PTR program?

(b) Would a detailed report on their energy usage improve customers' ability to benefit from a full PTR program?

RESPONSE:

See Mr. Alvarez's testimony in general. In particular, Mr. Alvarez believes the circumstances required to maximize the EE and DR benefits of a full PTR program include 1) program participation and marketing strategies that maximize the number of customers participating in a given PTR event per dollar; and 2) rebate incentive levels that maximize the response per participant per dollar of rebate.

a) Mr. Alvarez agrees that personalized power-saving recommendations could possibly increase customer participation and response per PTR event.
b) Mr. Alvarez agrees that detailed reports on energy usage could possibly increase customer participation and response per PTR event.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel As To Objection

QUESTION No. 33
Page 1 of 1

Referring to Alvarez testimony page 13, please define "belated."

RESPONSE:

Objection. The question is designed to be unduly burdensome, and seeks information which DEK can research just as easily as can the AG, since DEK certainly has access to a dictionary. Without waiving this objection, Mr. Alvarez states that he defines "belated" as anything other than the opportunity to enroll in text message notifications during initial program registration. To do otherwise, for example as a follow-up, even if immediate, significantly retards enrollment in text message notifications. This is confirmed by the fact that less than 10% of pilot test participants (74 of 899 per response to AG-DR-01-011(b)) enrolled in text message notifications. Further, as indicated in response to AG-DR-01-011(c)), the average time for text message notification to be added as a preference by a participant was three months post-initial registration.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ Counsel as to Objection

QUESTION No. 34
Page 1 of 1

Referring to Alvarez testimony page 13, lines 6-10, have the Kentucky Attorney General and/or Mr. Alvarez performed any study comparing the busy daily lives of Duke Energy Kentucky service area customers to Mr. Alvarez's daily life?

(a) If yes, please provide all such studies and any supporting papers and calculations.

RESPONSE:

Objection. The question is patently designed to annoy or harass the witness, and is not predicated upon obtaining relevant evidence. Without waiving this objection: No.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objection

QUESTION No. 35
Page 1 of 1

Referring to Alvarez testimony, page 13, lines 6-8, is Mr. Alvarez suggesting that, after enrolling in a program that provides notifications via email, he would then ignore his email account despite knowing that this is a method of notification?

(a) Have the Kentucky Attorney General and/or Mr. Alvarez performed any study demonstrating that Duke Energy Kentucky customers would similarly ignore email notifications?

(b) If yes, please provide all such studies and any supporting papers and calculations.

RESPONSE:

Objection. The question seeks information that is irrelevant to DEK's application in this docket, and is designed to annoy or harass the witness. Without waiving these objections, Mr. Alvarez suggests he would not modify the personal email account habits he maintains 365 days per year out of concern for missing 12 PTR event notifications via e-mail.

(a) No.
(b) Not applicable.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 36
Page 1 of 1

Have the Kentucky Attorney General and/or Mr. Alvarez performed any study on the impacts of offering text participation during enrollment versus the Company's process of offering text participation immediately after enrollment? If yes, please provide all such studies and any supporting papers and calculations.

RESPONSE:

No.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 37
Page 1 of 1

Do the Kentucky Attorney General and/or Mr. Alvarez disagree with the EM&V report statement that "[t]he results from the Duke Energy Peak Time Credit program were in line with the results seen in other programs."? Refer to Appendix E, page 75.

RESPONSE:

No, as to program impact levels. However, regarding participation levels, Mr. Alvarez does not agree that the results from the Duke Energy Peak Time Credit program were in line with participation levels seen in other programs.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 38
Page 1 of 1

Referring to Alvarez testimony pages 14-15 and 26, are the Kentucky Attorney General and/or Mr. Alvarez aware that Ohio eliminated all energy efficiency and demand response programs?

(a) If yes, is Mr. Alvarez suggesting that Duke Energy Kentucky should pay for and accept the costs and benefits of promoting PTR in Duke Energy Ohio territory?

RESPONSE:

Yes.

(a) No. Mr. Alvarez is suggesting that Duke Energy Ohio should pay for and accept the costs and benefits of promoting PTR in Duke Energy's Ohio territory 1) to maximize the benefits of Duke Energy Ohio's smart meter deployment for its Ohio customers; and 2) because Mr. Alvarez's projections of PTR program costs and benefits in DEK indicate that launching a PTR program in Ohio would likely deliver benefits to Duke Energy Ohio customers in excess of PTR program costs.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objection

QUESTION No. 39
Page 1 of 1

Referring to Alvarez testimony, page 15, lines 4-12, does Mr. Alvarez believe that co-promotion can increase the impacts of co-promoted EE and DR programs?

(a) If yes, is Mr. Alvarez aware that the Duke Energy Kentucky MyHER program was previously an opt-out program and that the Company was ordered to make it an opt-in program?

RESPONSE:

Yes.

(a) Objection, relevancy. The question exceeds the scope of the subject matter to which Mr. Alvarez testified, which is DEK's PTR program. Without waiving this objection, Mr. Alvarez states: No.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 40
Page 1 of 1

Referring to Alvarez testimony, page 15, lines 5-7, does Mr. Alvarez and/or the Kentucky Attorney General have any evidence that combining PTR with Power Manager will improve the impacts and the cost effectiveness of that program?

(a) If yes, please provide such evidence.

RESPONSE:

The Company has no direct evidence that combining PTR with Power Manager will improve the impacts and the cost-effectiveness of that (Power Manager) program. However, there is an extensive body of research which indicates that combining "enabling technologies" (such as Power Manager thermostats) with time-varying rates (such as PTR) increases the response to time-varying rate price signals (see Alvarez testimony, page 15 at 8).

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 41
Page 1 of 1

Does Mr. Alvarez agree that in economic terms, sending price signals to customers based on the cost of providing energy at the time it is consumed, is economically efficient and a driver of technology and innovation during high cost periods?

RESPONSE:

Yes.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 42
Page 1 of 1

Referring to Alvarez testimony, from page 16 line 19 to page 17, line 10, is it the AG's position that customer technology adoption such as solar rooftop and smart thermostats do not provide any benefit to customers and would not benefit from a TOU rate?

RESPONSE:

No, this is not the AG's position.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 43
Page 1 of 1

Referring to Alvarez testimony, page 17, lines 16 to page 18, line 4, does the Kentucky Attorney General and/or Mr. Alvarez have any studies, analysis, or other evidence to support the assertions made regarding low-income customers?

(a) If yes, please provide all such studies, analysis, or evidence.

RESPONSE:

When Mr. Alvarez's testimony was drafted, these assertions were based on his general experience with residential demand-side management programs. Since then, however, some research support for some of these assertions has been identified. Please see slides 22 and 23 of the LBNL presentation, "Experiences of Vulnerable Residential Customer Subpopulations with Critical Peak Pricing", attached.

SMART GRID INVESTMENT GRANT

CONSUMER BEHAVIOR STUDY ANALYSIS

Experiences of Vulnerable Residential Customer Subpopulations with Critical Peak Pricing

Peter Cappers, C. Anna Spurlock, Annika Todd, Ling Jin (LBNL)

Overview of SGIG Consumer Behavior Studies

- **DOE Smart Grid Investment Grant (SGIG) Funding Opportunity Announcement (FOA) was released in June 2009**
  - Goal: Provide more definitive answers to policymakers responsible for modernizing the country's electricity infrastructure, in part by funding studies/pilots
- **FOA stated ideal approach for conducting funded consumer behavior studies:**
  - Focus on highly dynamic pricing tariffs (i.e., RTP, CPP)
  - Random assignment of start date for customers to be exposed mandatorily to dynamic pricing as default rate design
  - Customers remain on such rates for at least two (2) years
  - Requirement to deliver highly granular customer-level data for subsequent DOE cross-project analysis

Overview of SGIG Consumer Behavior Studies (2)

	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Non-Rate Treatments										
IHD	●	●	●					●	●	
PCT	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	

Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)

AMI, Time-Based Rates, and Vulnerable Customers

- **Some stakeholders have raised concerns about the assumptions underlying the benefits assessments in AMI business cases**
  - Especially benefits associated with broader adoption of time-based rates enabled by AMI, which the SGIG CBS program focused on
- **Concerns are especially acute for low income, elderly and those with chronic illness (i.e., vulnerable) who are believed to be:**
  - Less capable of responding to such rates;
  - More willing to reduce essential electricity use to avoid high bills resulting in potential physical harm; and
  - More adversely affected by higher and/or more volatile bills

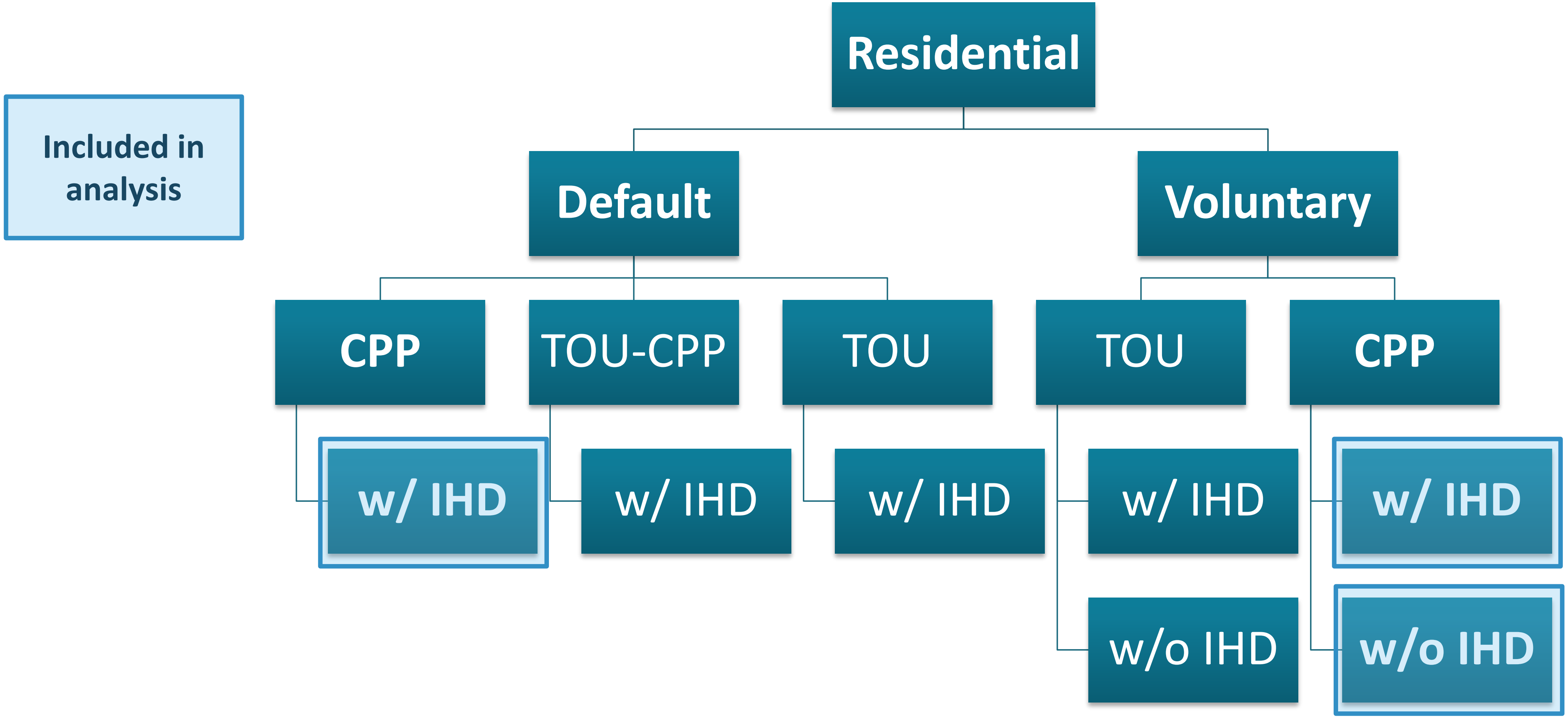
Outstanding Research Questions of Vulnerable Customers and Time-Based Rates

- **Do vulnerable subpopulations of customers:**
  1. Exhibit usage patterns (either in terms of their average usage or flexibility of usage) that differ from those of non-vulnerable subpopulations?
  2. Participate and stay enrolled in time-based rates at different levels than non-vulnerable subpopulations?
  3. Exhibit load response to time-based rates at different levels than non-vulnerable subpopulations?
  4. Benefit financially from time-based rates at different levels than non-vulnerable subpopulations?
  5. Curtail usage at the expense of comfort, well-being, or satisfaction to a greater extent than non-vulnerable subpopulations?

SGIG Consumer Behavior Studies Able to Address These Outstanding Research Questions

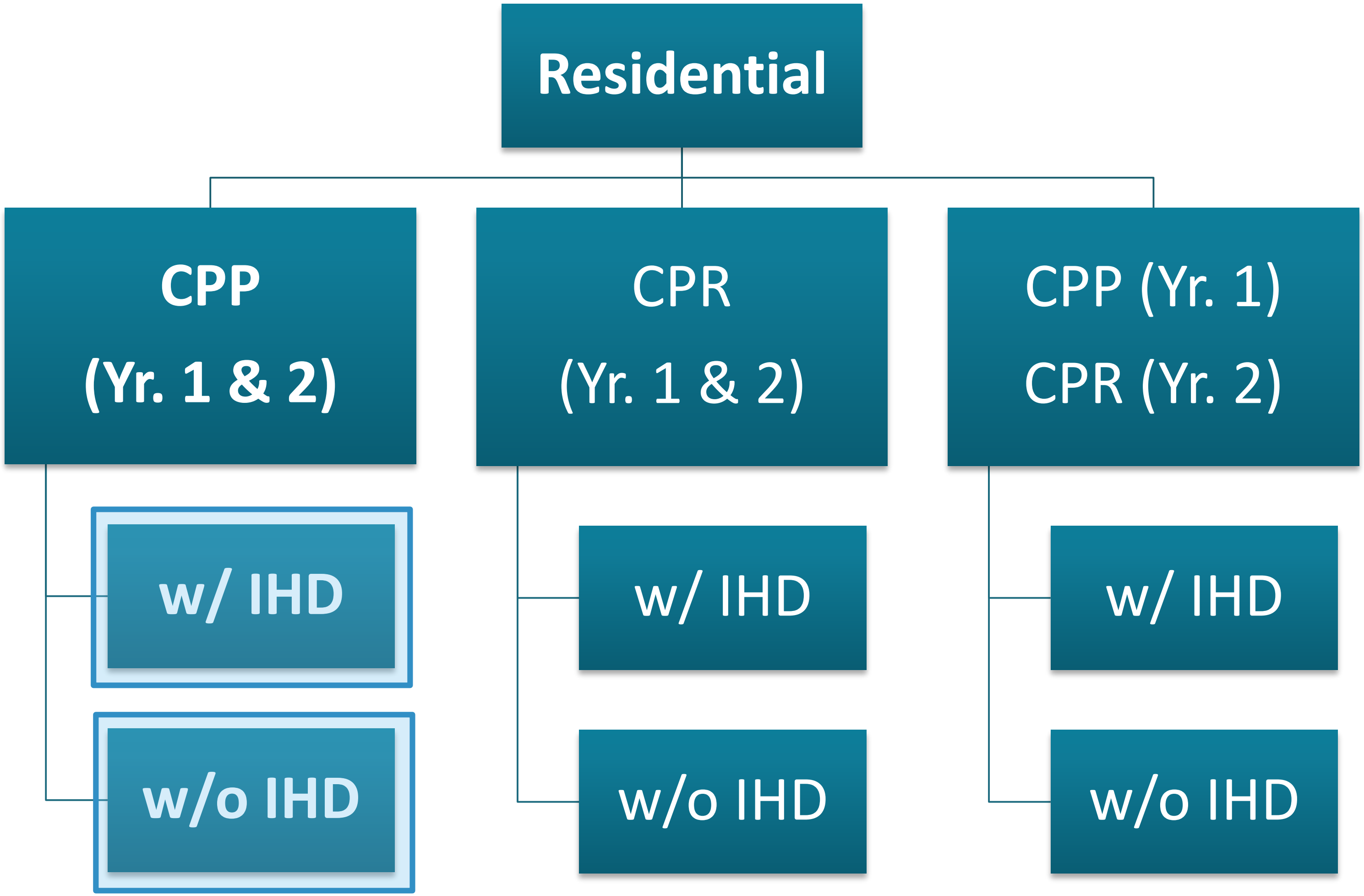
- **There has been a very modest amount of research concerning these research questions on the low-income community but little to no research on the elderly or those who are chronically ill**
- **An analysis of SMUD's and GMP's consumer behavior studies were able to contribute to this body of research because they fit the required criteria:**
  - Implemented a time-base rate (Critical Peak Pricing in particular);
  - Had sufficient participation data;
  - Had sufficient interval meter data; and
  - Had sufficient survey and other sources of demographic data to identify customers as vulnerable or not

SMUD Experimental Design



GMP Experimental Design

Included in analysis



Analytical Approach to Address Outstanding Research Questions

- **Neither SMUD nor GMP's study was designed to have the power to identify load responses of disaggregated customer groups**
  - We chose to combine multiple similar treatment arms for both utilities in our analysis, in order to maximize the potential of identifying any differences in load response, enrollment rates, and bill impacts.
    - SMUD: Voluntary CPP with In Home Display (IHD) offer and without IHD offer (Analyzed in combination)
    - GMP: Voluntary CPP with IHD and without IHD offer (Analyzed in combination)
    - SMUD: Default CPP with IHD offer (Analyzed independently)

Definitions of Vulnerable Customer Subpopulations

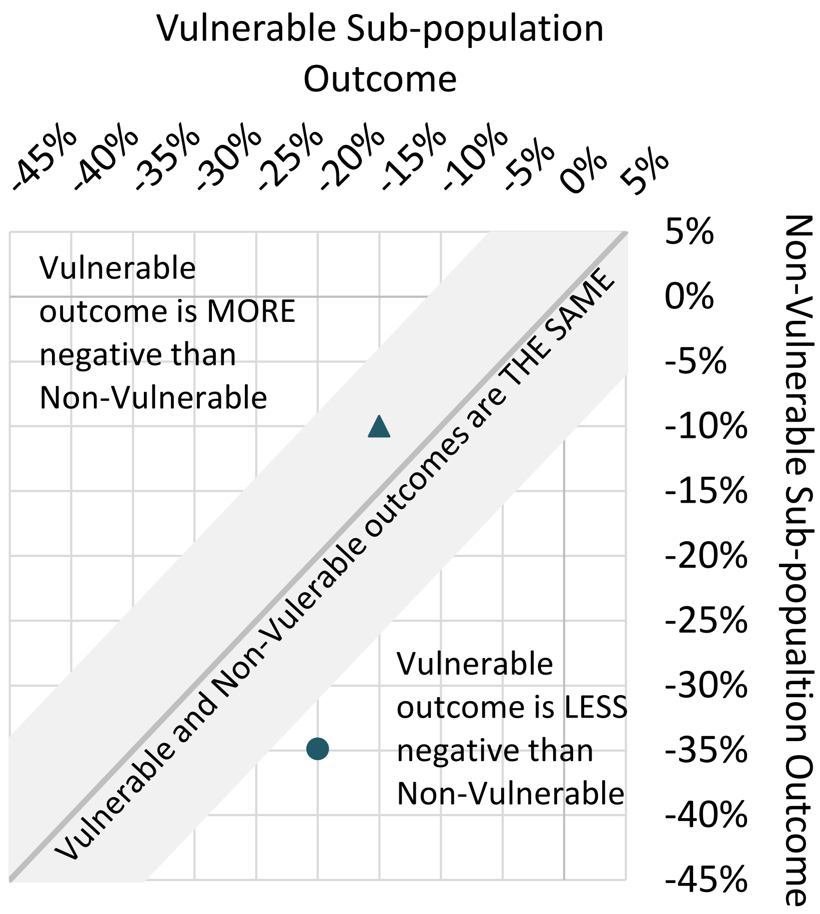
- **Low income**
  - Determined by reported income levels and the number of people living in the residence via utility-administered survey instruments and a state-specific Low Income Home Energy Assistance Program (LIHEAP) cutoff definition;
- **Elderly**
  - Determined by reported age of adults (those over 65 identified as elderly) living in the residence via utility-administered survey instruments; and
- **Chronically Ill**
  - Determined by reported existence of a chronic illness of individuals living in the residence via utility-administered survey instruments.

Percent of Survey Respondents Affiliated with the Identified Vulnerable Customer Subpopulations

	Low Income	Elderly	Chronically Ill
SMUD Voluntary Cells	39% (435/1119)	35% (407/1176)	9% (110/1209)
GMP Voluntary Cells	15% (69/463)	41% (230/560)	20% (111/558)
SMUD Default Cells	32% (80/248)	31% (80/262)	12% (31/264)
SMUD Control Cells	41% (87/211)	34% (78/227)	13% (31/233)
GMP Control Cells	16% (48/302)	42% (155/373)	25% (92/372)

Note: numbers in parentheses report the following: (# of households identified as vulnerable / # of households in total that responded to the relevant survey question).

Analysis Approach and Representation of Results

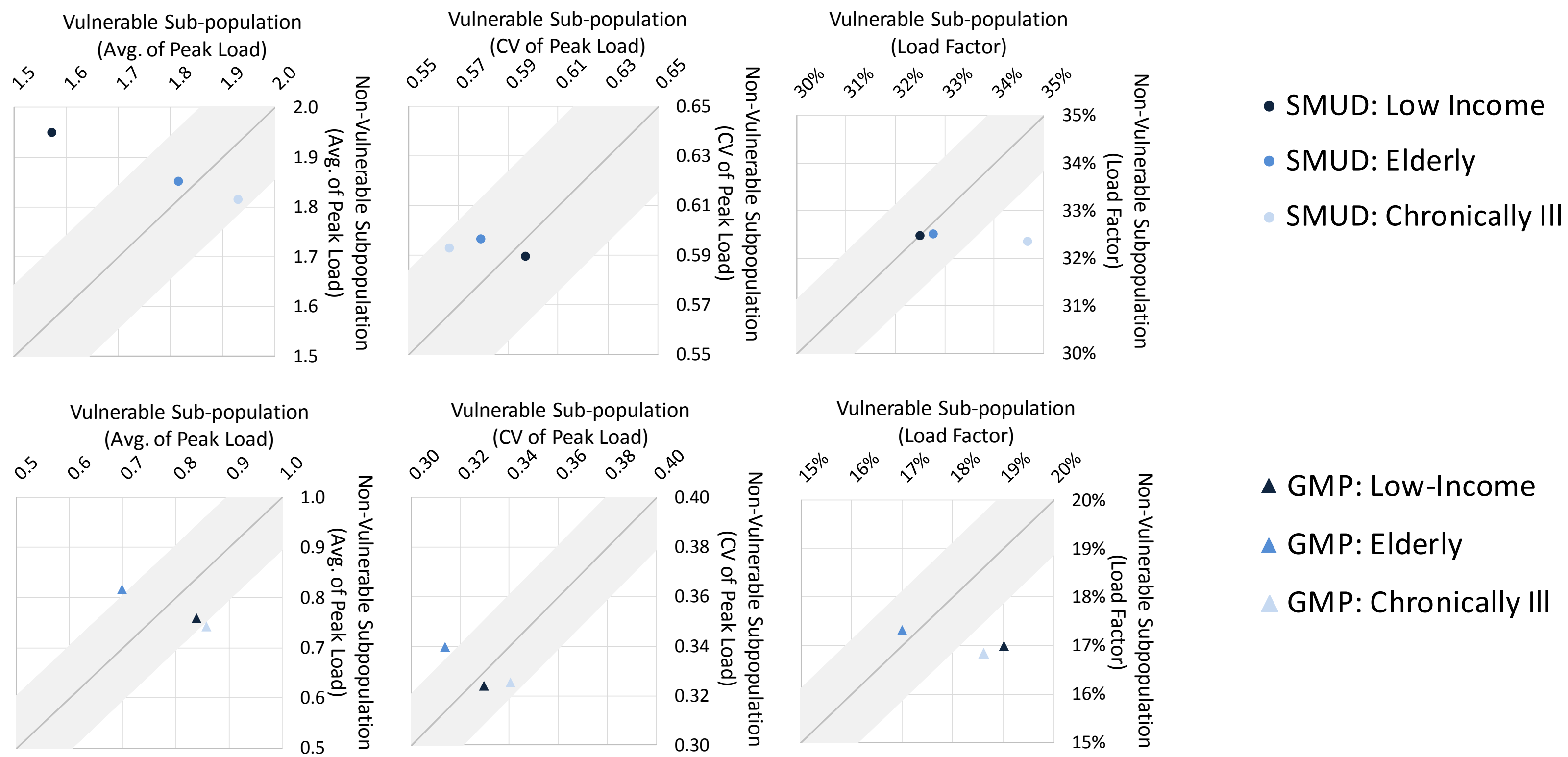


- Outcomes of interest for customers that fall into a given "vulnerable" category (e.g., elderly) are compared to that category's "non-vulnerable" counterpart (e.g., non-elderly).
- If a point lies on the 45-degree line then the outcome is the same between the two subpopulations.
- The further from this line a point lies, the greater is the difference in the outcome between the vulnerable and non-vulnerable subpopulations.
- Any points located outside the gray shaded area indicate the difference is statistically significant at a 90% confidence level

Results: Average Load and Load Flexibility

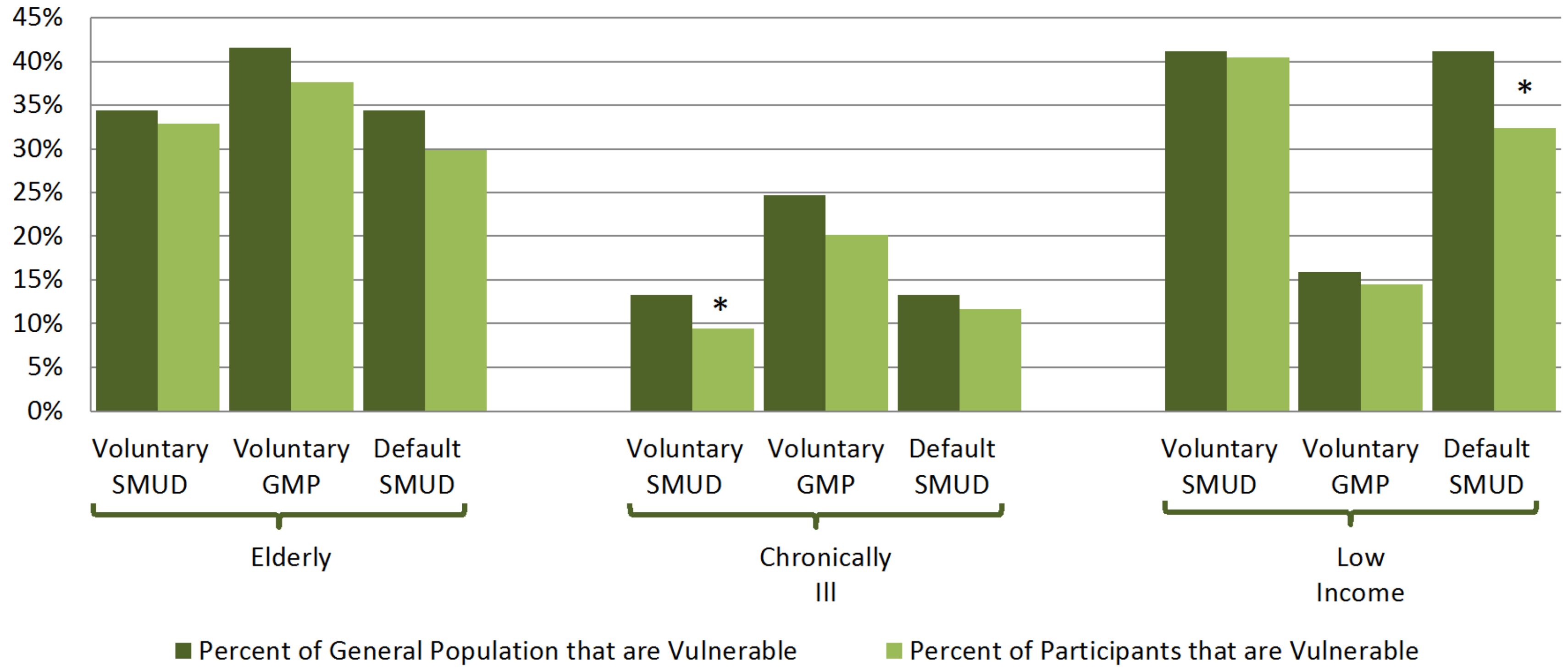
SMUD

GMP



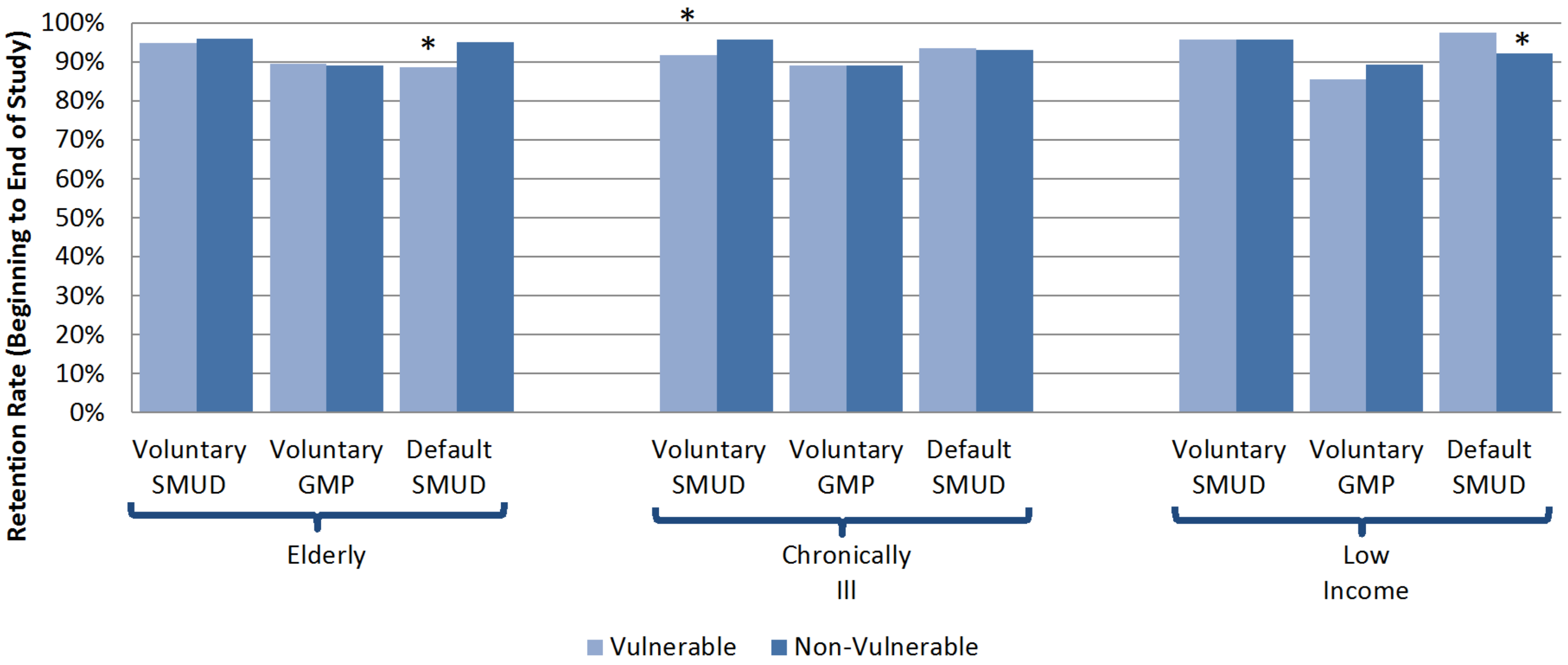
Note: For any of the points that lie in the gray bar area, the difference of the relevant metric for the vulnerable population was not statistically significant (at a 90% confidence level) relative to the non-vulnerable counterpart population. The gray bar in and of itself is not the 90% confidence interval, but rather a graphical way of showing which estimates are statistically significant at the 90% confidence level and which are not.

Results: Enrollment



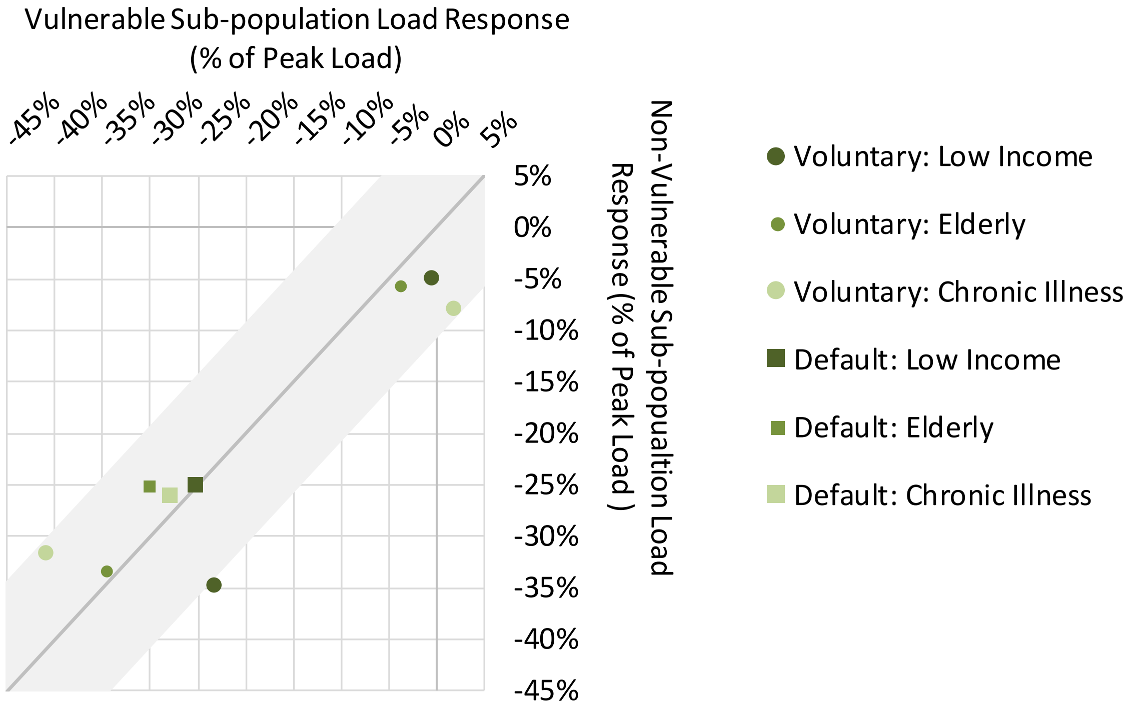
Note: These data are limited to those who responded to the survey. The percent of vulnerable households in the general population are based on those households from the control group that responded to the survey.
* indicates that the difference between the percent of study participants that are vulnerable versus the percent that are vulnerable in the general population are statistically significant at least at the 90% confidence level, all other differences are not statistically significant.

Results: Retention



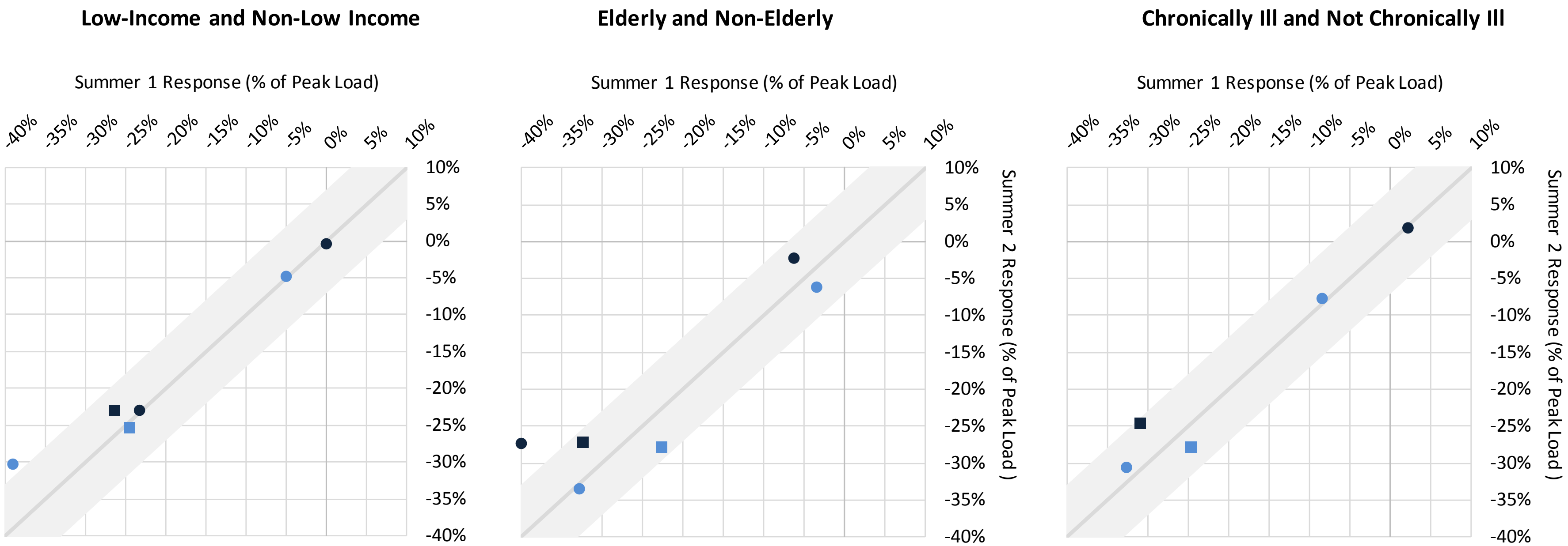
Note: * indicates that the difference in retention rate between the vulnerable and non-vulnerable study participants are statistically significant at least at the 90% confidence level, all other differences are not statistically significant.

Results: Load Response



Note: The markers in this graph indicate the estimated load response as a percent of average consumption. For any of the points that lie in the gray bar area, the difference between the estimated load response for the vulnerable population was not statistically significant (at a 90% confidence level) relative to the non-vulnerable counterpart population. The gray bar in and of itself is not the 90% confidence interval, but rather a graphical way of showing which estimated differences are statistically significant at the 90% confidence level and which are not.

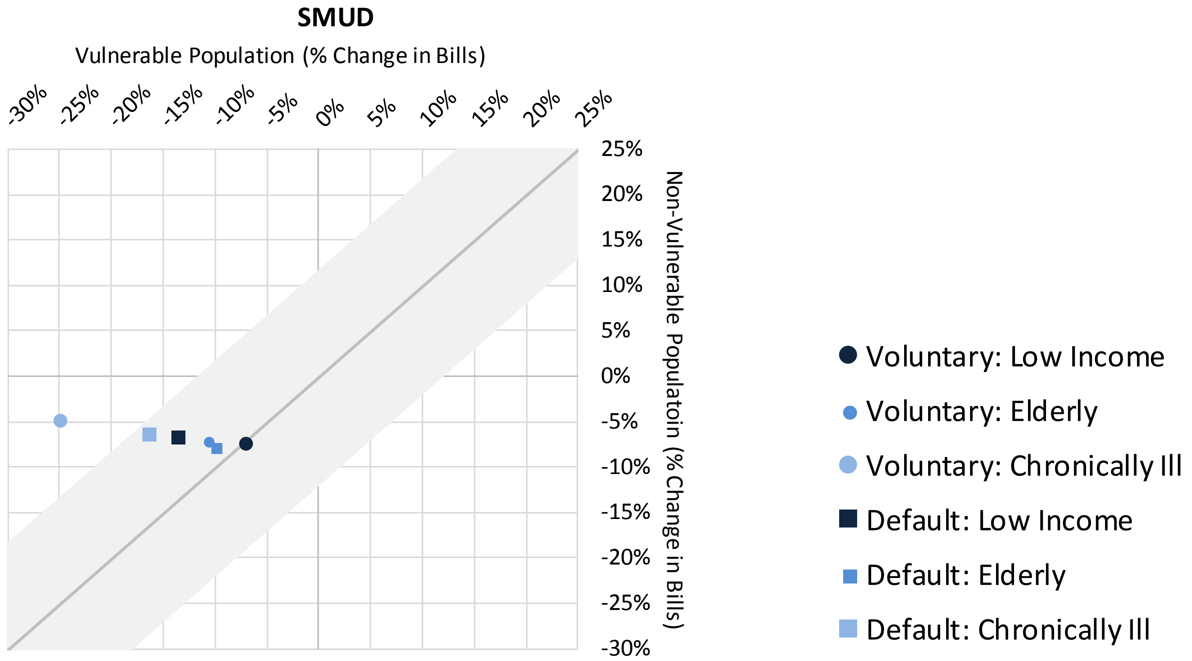
Results: Persistence of Load Response



Note: The markers in these graphs indicate the estimated load response as a percent of average consumption. For any of the points that lie in the gray bar area, the difference between the estimated load response in the first summer of the pilot was not statistically significant (at a 90% confidence level) relative to the second summer. The gray bar in and of itself is not the 90% confidence interval, but rather a graphical way of showing which estimated differences are statistically significant at the 90% confidence level and which are not.

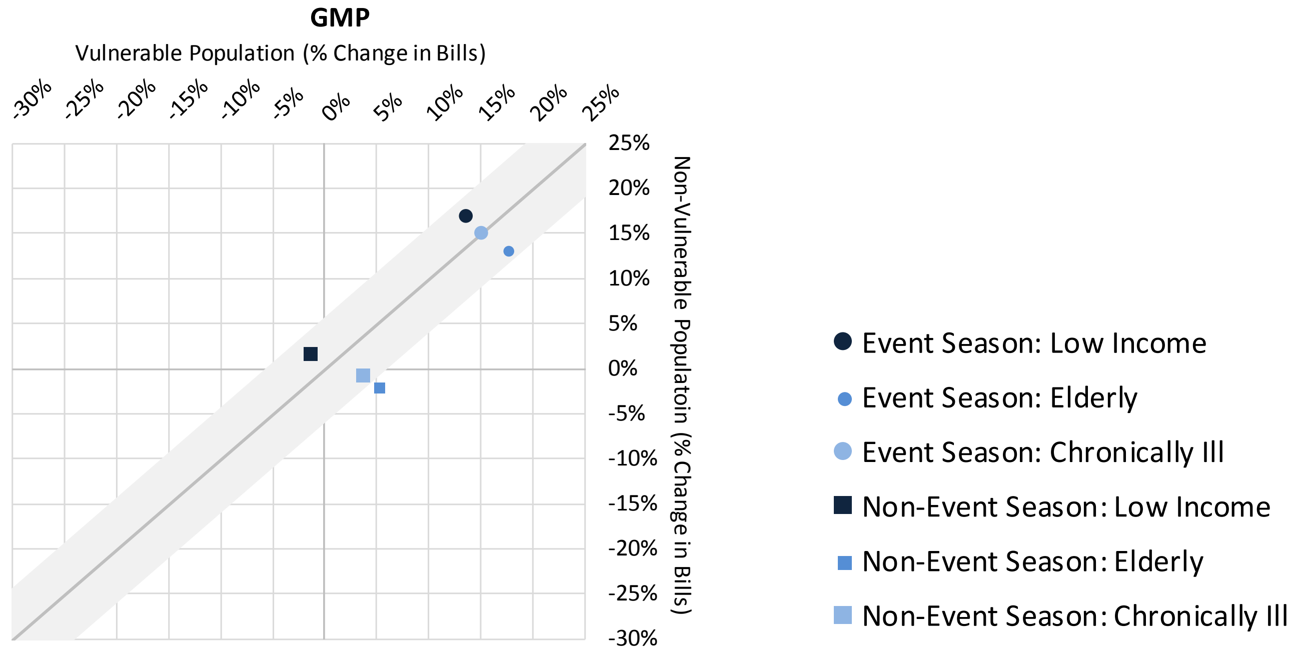
- Voluntary: Vulnerable
- Voluntary: Non-Vulnerable
- Default: Vulnerable
- Default: Non-Vulnerable

Results: SMUD Bill Impacts



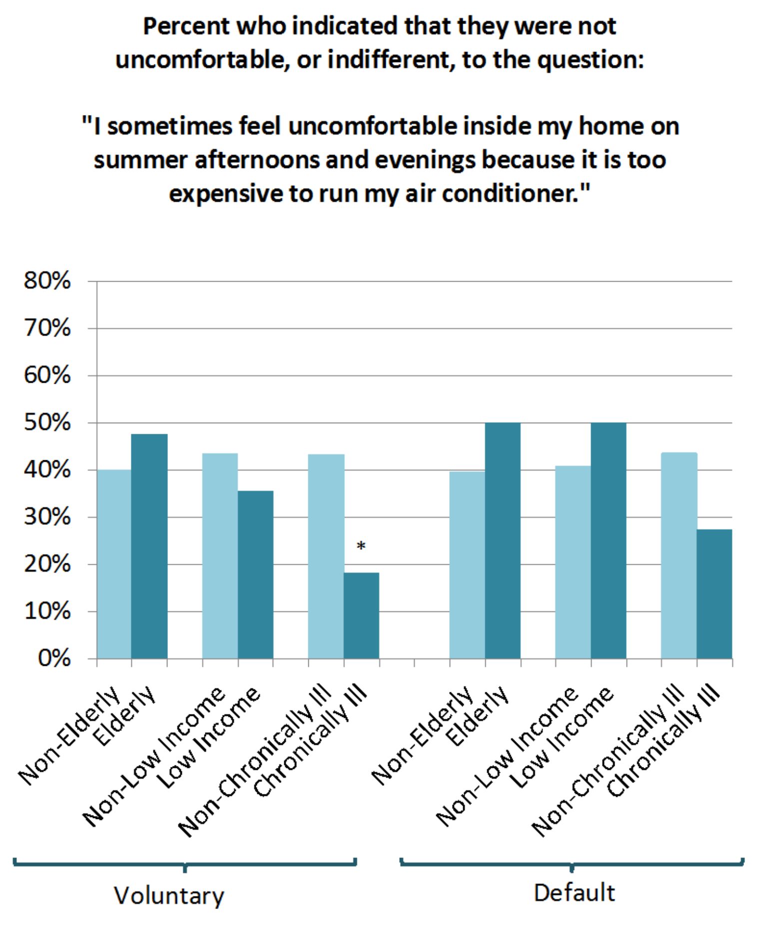
Note: The markers in this graph indicate the estimated bill impacts from the treatment rates as a percent of average expenditure. For any of the points that lie in the gray bar area, the difference between the estimated bill impact for the vulnerable population was not statistically significant (at a 90% confidence level) relative to the non-vulnerable counterpart population. The gray bar in and of itself is not the 90% confidence interval, but rather a graphical way of showing which estimated differences are statistically significant at the 90% confidence level and which are not. The estimates for SMUD were done during the event season only, as that was when the experimental rates were in effect.

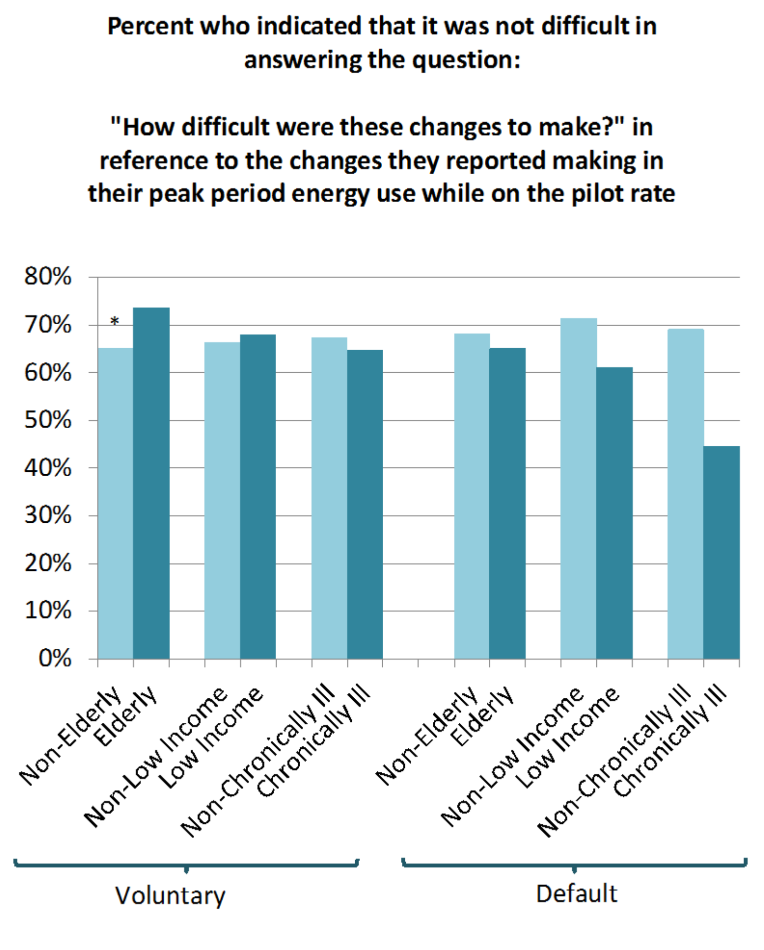
Results: GMP Bill Impacts



Note: The markers in this graph indicate the estimated bill impacts from the treatment rates as a percent of average expenditure. For any of the points that lie in the gray bar area, the difference between the estimated bill impact for the vulnerable population was not statistically significant (at a 90% confidence level) relative to the non-vulnerable counterpart population. The gray bar in and of itself is not the 90% confidence interval, but rather a graphical way of showing which estimated differences are statistically significant at the 90% confidence level and which are not. The estimates for GMP were done during both the event season and the non-event season separately, as GMP's rates were in effect throughout the year.

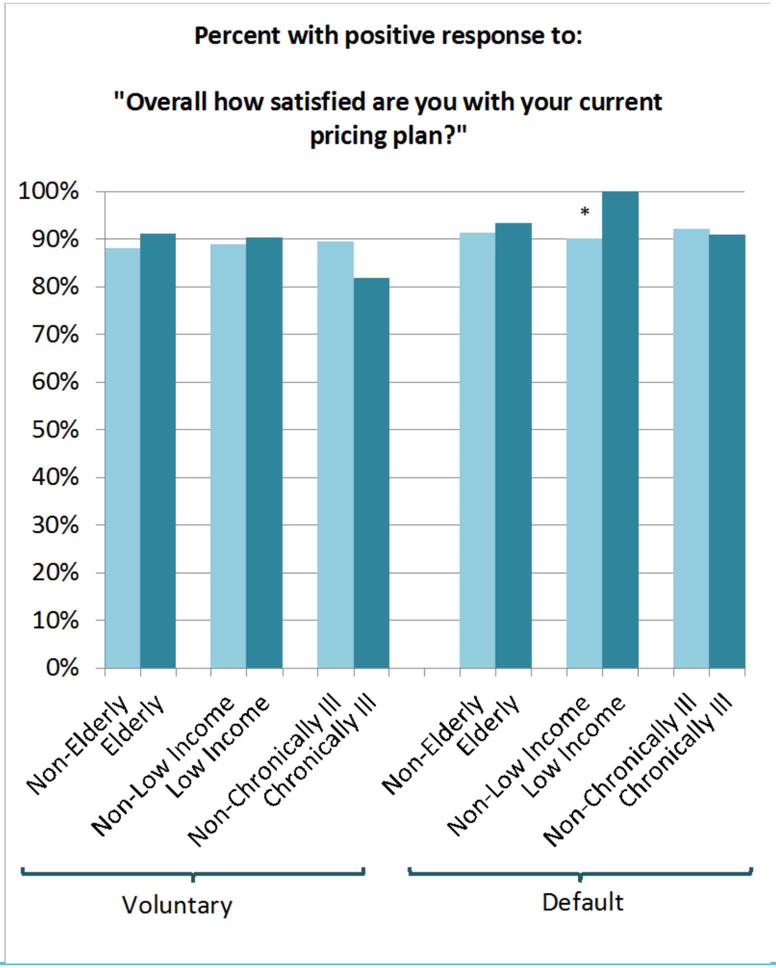
Results: Customer Satisfaction (SMUD)

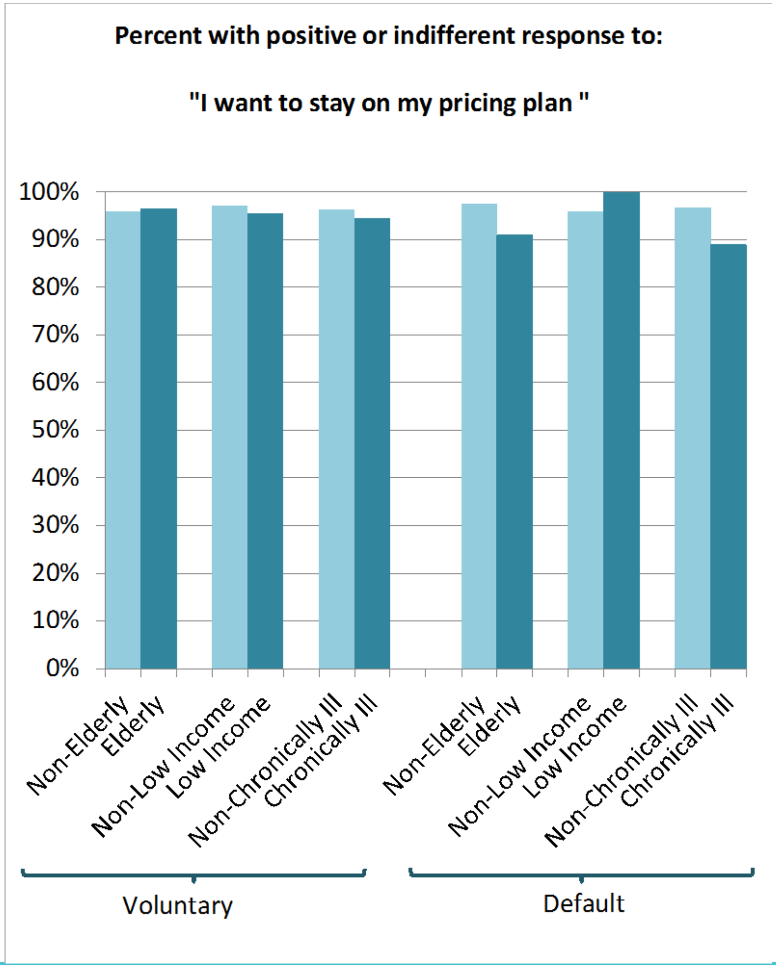




Note: The bars show the percent of favorable survey responses. * indicates the response rates between the vulnerable and non-vulnerable subpopulations is different with a confidence of 90% or higher. All other differences are not statistically significantly.

Results: Customer Satisfaction (SMUD)





Note: The bars show the percent of favorable survey responses. * indicates the response rates between the vulnerable and non-vulnerable subpopulations is different with a confidence of 90% or higher. All other differences are not statistically significantly.

Conclusions & Take-Aways (1)

- Average Peak Period Usage and Load Flexibility
  - The average peak period usage
    - Evidence that it can be lower for
      - Elderly customers
      - low-income customers
    - Evidence that it can be higher for
      - Chronically ill customers
  - Load variability/flexibility
    - Evidence that it is slightly lower for
      - All vulnerable subpopulations

Conclusions & Take-Aways (2)

- Enrollment
  - Vulnerable subpopulations participated in a CPP rate at similar levels in general as non-vulnerable subpopulations.
  - Exceptions:
    - chronically ill customers offered SMUD's voluntary rate participated at lower levels
    - low-income customers defaulted onto SMUD's CPP rate participated at slightly lower levels
- Retention
  - Comparable between vulnerable and non-vulnerable subpopulations
  - Exceptions (where statistically significant differences were identified):
    - low-income customers dropped out of SMUD's default rate at a slightly lower rate
    - chronically ill customers dropped out of SMUD's voluntary rate at a slightly higher rate
    - elderly customers dropped out of SMUD's default rate at a slightly higher rate

Conclusions & Take-Aways (3)

- Load Response
  - Vulnerable subpopulations were usually just as responsive on a proportional basis as their non-vulnerable counterparts over the entire study period, though exhibiting varying degrees of persistence.
  - There were no differences in response level or persistence of response between vulnerable and non-vulnerable customers on the default rate.
  - In the voluntary rates, the only case in which there was a statistically significant difference was for low-income customers, who exhibited a slightly lower load response as compared to their higher income counterparts. However, these voluntary low-income customers had a persistent load response between the first and second summer of the pilot, while higher income customer load response attenuated over time.

Conclusions & Take-Aways (4)

- Bill Impacts
  - Vulnerable subpopulations financially benefited at roughly similar proportional levels to their non-vulnerable counterparts.
  - SMUD:
    - Rate was designed to be revenue neutral during the event season summer months, but all customer groups actually experienced bill savings as a result of being on the rate.
    - Chronically ill customers experienced even lower bills relative to their non-vulnerable counterparts.
  - GMP:
    - Rate was designed to be revenue neutral over the entire year, but events were only called during the summer.
    - Bills were higher for all customer groups during the event season, and higher for elderly customers during the non-event season relative to non-elderly customers.

Conclusions & Take-Aways (5)

- Customer Satisfaction
  - Using survey data available only from SMUD, we are able to analyze the responses of customers to questions regarding their comfort, the difficulty they faced in changing their usage, and their overall satisfaction with the rate.
  - With respect to reported comfort and difficulty of changing behavior there were no differences between vulnerable and non-vulnerable subpopulations in the default treatment.
  - In the voluntary treatment, chronically ill customers were more likely to report discomfort and elderly customers were less likely to indicate that behavior changes they undertook were difficult, relative to their respective non-vulnerable counterparts.
  - However, overall satisfaction levels were extremely high across all subpopulations (with between 91% and 100% indicating they would want to remain on the rate), and low-income customers in the default treatment indicating statistically significantly higher levels of satisfaction than their higher income counterparts.

Conclusions & Take-Aways (6)

- The experience of vulnerable customer subpopulations in GMP's and SMUD's consumer behavior studies suggests there may be some differences from those who would not be considered vulnerable, but many such differences would be considered small in magnitude and are not statistically significant.
- However, these results often differ both across the three vulnerable subpopulations, and across the two utilities included in this analysis.
- This suggests a need to design and implement time-based rate studies utilizing experimental designs that are specifically targeted at these vulnerable subpopulations to gain more definitive and more broadly applicable results.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 44
Page 1 of 1

Referring to Alvarez testimony on page 32, lines 2-10, have the Kentucky Attorney General and/or Mr. Alvarez performed or obtained any studies or analysis quantifying PJM price decreases resulting from PTR program participation in Kentucky?

(a) If yes, please provide all such studies or analysis.

RESPONSE:

Assuming the Company is referring to the DRIPE discussion on page 30, lines 1-11, no. As cited in Mr. Alvarez's testimony, the 1% reduction in price for every 1% reduction in demand is a conservative interpretation of a study completed on a PJM node in Illinois (2% reduction in price for every 1% reduction in demand, cited on page 26 at line 4).

(a) Not applicable.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 45
Page 1 of 1

Referring to Alvarez testimony on page 32, lines 2-10, does Mr. Alvarez also believe that PJM prices increase when a customer increases demand for electricity during peak times?

(a) If yes, does Mr. Alvarez believe the customers should be required to bear the costs of such an increase?

RESPONSE:

If enough individual customers, or a large enough customer, increase demand for electricity simultaneously during peak times, yes.

(a) Yes.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 46
Page 1 of 1

Does Mr. Alvarez believe that PJM price decreases attributable to PTR program participants decreased peak demand will be sufficient to make the PTR program cost-effective?

(a) If yes, please provide any analysis or study performed to support this assertion.

RESPONSE:

It is not likely that PJM price decreases alone will be sufficient to make the PTR program cost-effective. Appendix B to Mr. Alvarez's testimony provides details of the various sources of value from a PTR program that contribute to program cost-effectiveness.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 47
Page 1 of 1

Referring to Alvarez testimony, page 29, lines 3 to 7, does Mr. Alvarez believe that a 20% participation rate is a better estimate than Duke Energy Kentucky specific results from contacting all eligible customers requesting participation?

RESPONSE:

Yes. The 20% participation rate is in line with participation rates in other PTR programs per the study cited (page 21 at line 18).

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 48
Page 1 of 1

Referring to Alvarez testimony, page 29, lines 3 to 7, Mr. Alvarez states that his 20% participation rate assumption is "based on experience from other PTR programs." Please provide a list of all such PTR programs, and any reports or analysis from such programs.

RESPONSE:

Please refer to the study cited on page 21 at line 18. The Study does not name the utilities/PTR programs identified with the 28%, 19%, or 10% enrollment rates, nor does the Study provide reports or analyses from such programs. (See Study page 31, Table 1 for available information. "CPR" is an acronym for "Critical Peak Rebate".)

Further, the AG notes the cited study contains participation data for rates with critical peak price components similar to the one the Company just proposed in its rate case (Docket 2022-00372). Table 1 on page 31 of the study indicates that six rates with critical peak price components (denoted by "CPP") but not a critical peak rebate averaged a participation rate of just 10.3%. This is only about one-half of the average participation rate (19%) for the three critical peak rebate programs.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 49
Page 1 of 1

Does Mr. Alvarez include any free ridership assumption in his cost-benefit analysis in Appendix B to his testimony? If not, why?

RESPONSE:

Mr. Alvarez uses average demand response levels from the Evaluator's report (0.14kW per event, per participant) as the basis for estimating benefits in Appendix B. As a result, yes, he includes free ridership impacts to the same extent incorporated in the Evaluator's findings.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 50
Page 1 of 1

Does Mr. Alvarez's analysis in Appendix B include diminishing load impacts over a 5 year period?

RESPONSE:

No.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objection

QUESTION No. 51
Page 1 of 1

Referring to Alvarez testimony, page 29, lines 3 to 7, please provide the load impact estimates per participant per hour for all other programs over the last 5 years that the Mr. Alvarez uses as comparison to Duke Energy Kentucky participants? Provide the information separately identifying each program.

RESPONSE:

Objection. The question assumes facts not in evidence. Without waiving this objection, Mr. Alvarez states: This data request makes an errant assumption. Mr. Alvarez did not use the load impact estimates per participant from "other PTR programs" in his analysis. Mr. Alvarez used only the 0.14kW impact estimate per event, per participant from the DEK PTR Pilot Evaluator in his projection of PTR program benefits. The only datapoint from the "other PTR programs" referenced were the participation rates (28%, 19%, and 10%) used to inform the 20% PTR participation rate Mr. Alvarez assumed in his analysis.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 52
Page 1 of 1

Referring to Alvarez testimony, page 29, lines 3 to 7, Mr. Alvarez states that his 20% participation rate assumption is "based on experience from other PTR programs." Does the Mr. Alvarez believe that the Duke Energy Kentucky service area customers areas are identical in their behavior to customers in other jurisdictions?

RESPONSE:

Mr. Alvarez does not believe that Duke Energy Kentucky service area customers are identical in their behavior to customers in other jurisdictions. Instead, Mr. Alvarez believes that the behavior of customers in other jurisdictions can be used to inform projections of some behaviors (for example, PTR program participation) of customers in the Company's service area.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 53
Page 1 of 1

Referring to Alvarez testimony, page 23, line 19 to page 24, line 3, what was the range of conservation impacts in the 24 studies of TOU rates reviewed by Mr. Alvarez?

(a) Please provide all 24 studies reviewed and any supporting papers or calculations.

RESPONSE:

The average conservation impact in the 24 studies of TOU rates reviewed by secondary researchers (not Mr. Alvarez) ranged from 0% to 13%. Please refer to Table 1 in the cited research for more information.

(a) Mr. Alvarez does not have access to the studies reviewed by the secondary researchers (Chris King and Dan Delurey as cited). Please refer to Table 1 in the cited research for more information.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 54
Page 1 of 1

Referring to Mr. Alvarez's analysis in Exhibit B, does Mr. Alvarez assume that the average usage of incremental participants will be the same as the current program participants?

(a) If so, why?

RESPONSE:

Yes.

(a) Mr. Alvarez assumed that the average usage of incremental participants will be the same as that of the current program participants because the average usage of DEK residential customers overall (11,409 kWh in 2020 and 11,452 in 2021 per EIA Form 861) is somewhat greater than the average usage of current program participants (10,684.5 kWh per the response to AG-DR-01-007 (a) and (b)). Assuming that the average usage of incremental participants will be the same as that of the current program participants is therefore a conservative assumption in the projection of program benefits.

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 55
Page 1 of 1

Referring to Alvarez testimony pages 14-15 and 26, does Mr. Alvarez and/or the Kentucky Attorney General believe that this proceeding has relevance to and is binding with regard to Duke Energy Ohio's service area?

RESPONSE:

Mr. Alvarez states: No. By referring to the Duke Energy Ohio service area, Mr. Alvarez only intends to indicate that if the Company's sister utility launched a Full PTR program in Ohio: 1) PTR program participation in Kentucky might be higher; 2) marketing costs per unit of demand response might be lower (benefitting Kentucky customers); and 3) DRIPE impacts would be higher (benefitting Kentucky customers).

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ

QUESTION No. 56
Page 1 of 1

Does Mr. Alvarez believe that the elevated LMP prices related to the current energy environment will endure over the next 5 years?

RESPONSE:

Mr. Alvarez has no opinion regarding the elevated LMP prices related to the current energy environment and their endurance over the next 5 years. This is precisely why Mr. Alvarez employed the same assumptions for such prices in his analysis as the Company employed in its DSM program Application (as provided in response to AG-DR-01-022).

WITNESS / RESPONDENT RESPONSIBLE
PAUL J. ALVAREZ / Counsel as to Objection

QUESTION No. 57
Page 1 of 1

Referring to Alvarez testimony, page 31, lines 1-2, please provide all natural gas price forecasts on which Mr. Alvarez relies for his statement that natural gas prices will grow.

RESPONSE:

Objection. The question misinterprets and mischaracterizes Mr. Alvarez's statement, and as such assumes facts not in evidence. Without waiving this objection, Mr. Alvarez states: Mr. Alvarez did not rely upon any particular gas price forecast. Rather, he believes it is commonly understood that in the long-term, gas prices are more than likely to increase for a variety of reasons, including inflationary pressures. He is only stating that given that likely long-term growth, the on-peak/off-peak energy price differential benefit will also grow. This is due to economically-efficient PJM generation dispatch decisions. On-peak generating resources are more typically natural-gas fired, and generally less energy-efficient, than off-peak generating resources, thus using more natural gas and contributing to a higher on-peak/off-peak energy price differential in the PJM energy market.