STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

Application of Baltimore Gas &	**)**	
Electric For Adjustments to its Electric	**)**	**Case No. 9406**
and Gas Base Rates	**)**	
___________________________________	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF PEOPLES COUNSEL

PUBLIC VERSION

Resource Insight, Inc.

FEBRUARY 8, 2016

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil-engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified about three o hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and six Canadian provinces, and two US Federal agencies. This testimony has included the many reviews of utility cost-allocation studies, revenue-allocation proposals and rate designs.

Q: Have you testified previously before the Commission?

A: Yes. I have testified approximately 16 times before the Commission, from 1990 through 2015, as follows:

- Case No. 8278, on the adequacy of the integrated resource plan of Baltimore Gas & Electric (BGE);
- Case No. 8241, Phase II of BGE's Application for CPCN for the Perryman Project;
- Case No. 8473, Review of the Power Sales Agreement of BGE with AES Northside;
- Case No. 8487, BGE 1993 Electric Rate Case, on cost allocation and rate design;
- Case No. 8179, Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run;
- Case No. 8697, BGE 1995 gas rate proceeding, on cost allocation and rate design;
- Case No. 8720, Washington Gas Light (WGL), on DSM avoided costs and least-cost planning;

- Case No. 8725, the proposed merger of BGE and Potomac Electric Power Company (PEPCo), on allocation of merger benefits and rate reductions;
- Case No. 8774, the proposed Allegheny Power-Duquesne merger;
- Case Nos. 8794 and 8804, BGE restructuring;
- Case No. 8795, Delmarva Power & Light (DP&L) restructuring;
- Case No. 8797, Potomac Edison restructuring;
- Case No. 9036, BGE's 2005 rate proceeding;
- Case No. 9159, Columbia Gas's 2009 rate proceeding; and
- Case No. 9230, BGE's 2010 rate proceeding.
- Case No. 9361, the proposed merger of Exelon and Pepco Holdings.
- Case Nos. 9153, et al., the 2015 review of the EmPOWER Maryland programs.

I testified on behalf of the OPC in each of these proceedings, other than Case No. 9361, in which I testified on behalf of the Sierra Club and Chesapeake Climate Action Network.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Maryland Office of Peoples Counsel.

Q: What is the scope of your testimony?

A: I review some of the benefits that BGE asserts are provided by residential programs supported by the advanced meters of BGE's recent Smart Grid investment:

- The Smart Energy Rewards (SER) demand-response program.
- Smart Energy Manager (SEM) energy-efficiency program.

- Incremental savings from the pre-existing PeakRewards (PR) direct load-control program.

Q: What aspects of BGE's benefit estimates do you review?

A: My review focused primarily on the following four categories of program benefits, in $/kWh and $/MW-day:[1]

- BGE revenues from the SER and incremental PR for participation in the PJM capacity and energy markets.
- Costs avoided by BGE ratepayers due to reductions in the energy they consume and in the capacity obligation allocated to them by PJM.
- Reductions in prices paid for capacity and energy by Maryland ratepayers, due to price mitigation from additional supply and reduced demand.
- Reduced investments in transmission and distribution due to lower loads.

In BGE's terminology, the benefits related to the generation market are "non-operational" benefits, while T&D savings are a portion of the "operational" benefits (which also include various operating costs). I will refer to all the generation benefits and the avoided T&D as program benefits, since BGE attributes all those benefits to the operation of its three programs (SER, SEM, and PR).

The system benefits claimed by BGE are described at a high level of generality in the testimony of BGE witness William Pino, and documented

[1] BGE also includes about $4 million in avoided environmental costs, based on the $2/MWh value estimated by Itron (Development and Application of Select Non-Energy Benefits for the EmPOWER Maryland Energy Efficiency Programs, August 5, 2014). This value is too small to warrant much attention. Any adjustments to the estimate of program energy savings should also affect the environmental benefits.

primarily in the Market Benefits spreadsheet provided in Attachment 15 to Staff DR 6-02.

In Exhibit PLC-2, I attach the data requests that I cite, excluding only the bulky spreadsheets, such as Attachment 15 to Staff DR 6-02. Confidential responses are attached in Exhibit PLC-3.

Q: Did you review any other matters?

A: In addition to reviewing and as appropriate re-estimating these unit-price values per kilowatt-hour and megawatt-day, I reviewed some related issues, such as the extent to which the types of peak reduction achieved by the various programs would affect the capacity costs borne by BGE ratepayers and other Maryland ratepayers. I also offer some comments on the treatment of the payments to SER participants and the magnitude of SER savings.

Q: What do you mean by "types of peak reduction"?

A: The term "peak" has a range of meanings, in a variety of applications. "Peak load" may refer to PJM's maximum load on a single annual hour, on several monthly maximum hours, or many high-load hours. Other types of peak may be defined as the maximum load (or a number of high loads) for BGE, SWMAAC, MAAC, a particular BGE rate class, a transmission line, a substation, or a feeder. Each demand-related cost category is driven by its own type of peak, which may be different from that driving other costs.

Q: Are the categories of program benefits for which BGE claims benefits from the smart meter programs all costs that can be avoided by some types of load reductions?

A: Yes. These categories of benefits are real. The questions I address are whether the BGE has properly estimated the benefits, including whether the nature of the programs will provide those benefits.

Q: Will you present conclusions about the cost-effectiveness of BGE's smart-grid investment?

A: No. The testimony of Max Chang, on behalf of OPC, combines my unit-price results with corrected estimates of program energy and capacity savings, and of operational benefits, to determine the overall cost-effectiveness of the investment.

Q: How important are the various portions of the benefits that you review?

A: Table 1 disaggregates the program benefits among the three programs and the various components that BGE includes.[2]

Table 1: Breakdown of BGE Claimed System Benefits, $M in 2015 PV

	SER	SEM	PR	Total
Generation Capacity				
Capacity Revenue	[redacted]	[redacted]	[redacted]	$43
Avoided Capacity Cost	[redacted]	[redacted]	[redacted]	$62
Capacity Price Mitigation				$213
Supply Side	[redacted]	[redacted]	[redacted]	[redacted]
Demand Side	[redacted]	[redacted]	[redacted]	[redacted]
Transmission and Distribution				
Transmission	[redacted]	[redacted]	[redacted]	$115
[redacted]	[redacted]	[redacted]	[redacted]	$88
Energy Revenue				$20
LMP	[redacted]	[redacted]	[redacted]	[redacted]
Emergency	[redacted]	[redacted]	[redacted]	[redacted]
Avoided Energy Cost	[redacted]	[redacted]	[redacted]	$137
Energy Price Mitigation	[redacted]	[redacted]	[redacted]	$101
[redacted]	[redacted]	[redacted]	[redacted]	$778

Note: "–" indicates exactly zero benefit, while "$0" indicates that BGE estimated less than $0.5 M benefit.

The highlighted numbers in this chart are CONFIDENTIAL.

[2] The data in Table 1 are derived from the cover sheet of Staff DR 6-02, Attachment 15. BGE's allocation of the T&D benefits between the SER and SEM programs is based on the simple total of the claimed load reductions over the analysis period, and thus does not accurately allocate the PV benefits.

The claimed benefits are dominated by the capacity benefits of the SER program (59% of the total) and the energy reductions that BGE attributes to the SEM program (29%).

Q: Please summarize your conclusions.

A: The benefits claimed by BGE are overstated due to over a dozen distinct errors (in addition to any overstatement of savings discussed in the testimony of OPC witness Max Chang), the most important of which are as follows:

- The SER and PR load reductions, given their rarity and timing, are unlikely to affect transmission or distribution investment.
- For similar reasons, the capacity obligation for BGE and capacity price for all Maryland customers will not be significantly reduced by the SER and PR load reductions.
- BGE overstates the avoided energy cost and energy price mitigation, by including the capacity-related portion of the standard offer as part of the energy benefit. Energy savings do not reduce the capacity costs allocated to the BGE zone or to MD, and BGE's analysis deals separately with the capacity avoided cost and price mitigation.
- BGE's estimate of energy price mitigation is grossly overstated, because BGE has incorrectly assumed that energy prices for each of the Maryland zones is driven solely by BGE load. In reality, the BGE energy price is driven by loads over a large area (probably most of PJM, and possibly adjacent regions), as are the energy prices for PEPCo, Delmarva and Potomac Edison, and the prices in each of those other Maryland zones are more sensitive to load in that zone than in load in the BGE zone. A 1% change in BGE load appears to reduce energy

prices by about 0.1% to 0.6% (depending on the zone and period), rather than the 2.1% to 2.5% that BGE assumes in its analysis.

All of these errors and the lower-impact errors are discussed in Sections III through V and summarized in Section VI.

III. Claimed Generation Capacity Benefits

A. Capacity Revenue

Q: Have you identified any problems in BGE's estimate of capacity revenue?

A: No. While the pricing of the SER and PR capacity in the 2019/20 capacity year is inherently speculative, the capacity revenue in earlier years has largely been fixed by the Base Residual Auction (BRA) for each of the earlier years.[3] Starting in 2020/21, the BGE programs will no longer be eligible to participate in the capacity market, and BGE does not claim any benefit after May 2020.

B. Avoided Capacity Cost

Q: How does BGE estimate avoided capacity costs?

A: BGE's analysis can be broken down into three steps. First, BGE estimates a measure of peak load reduction, from each program, for the summers of 2013 through 2025, as follows:[4]

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[3] I assume that BGE has correctly reported the capacity it cleared from each of those programs, and that it will not require any purchases of capacity in the Incremental Auctions to fulfill its obligations.

[4] BGE does not claim any avoided capacity cost from the PR program.

- For SER, for 2013 to 2015, BGE identifies the subset of customers who received a Peak Time Rebate for reducing usage in the incentive period of the ESDs, compared to the average in up to three recent days. For those customers, BGE estimates the average per-customer load reduction the hours ending at 17 hours over the ESDs in the year, adds line losses, normalizes to an assumed peak condition of 83° WTHI, and multiplies by the number of customers and assumed participation rate.[5] After 2015, BGE keeps the SER savings per customer constant, but increases participation by increasing customer number, eliminating the control group, and increasing smart-meter penetration from 90% to 99%.
- For SEM, BGE assumes that participants reduce their peak consumption by the same percentage as annual consumption by 0.99% in 2013, 1.4% in 2014, and 1.5% in 2015 through 2025. While it does not specify what type of peak it assumes is reduced by the SEM program, BGE appears to assume that all loads are reduced by the same percentage.

Second, BGE assumes that each megawatt of the SER and SEM load reductions in a particular year (T), other than SER capacity bid into the PJM auction, results in a 0.33 MW reduction in the zonal load forecast used in year T+1 for the capacity delivery year that starts in year T+4, 0.66 MW in the forecast used in year T+2 for delivery year T+5, and a full MW in the forecasts used in years T+3 and after for delivery years T+6 and after.

Third, BGE multiplies the assumed forecast reductions by a reserve margin (the PJM Forecast Pool Requirement) and the BGE zonal load price

[5] Hour 17 was the PJM peak on six of the ten ESDs to date. One peak occurred in hour 15, and four in hour 16 (including the highest PJM loads in the 2014 and 2015 ESDs).

of capacity, which is the MAAC price in 2014/15 through 2016/17 and the RTO price for 2017/18 and later.

Q: What problems have you found in this analysis?

A: Mr. Chang will address issues in the first step (estimation of load reductions) in his testimony. My testimony in this section concentrates on the second step (the effect of the load reductions on the BGE zonal peak forecast and capacity obligation). Specifically, BGE's model does not reflect well the development of the PJM forecasts that drive capacity obligations, and the SER load reductions are not likely to reduce peak forecasts. In addition, I start with some brief observations on problems in BGE's estimates of the program load reductions.

1. BGE's Estimates of Peak Reductions

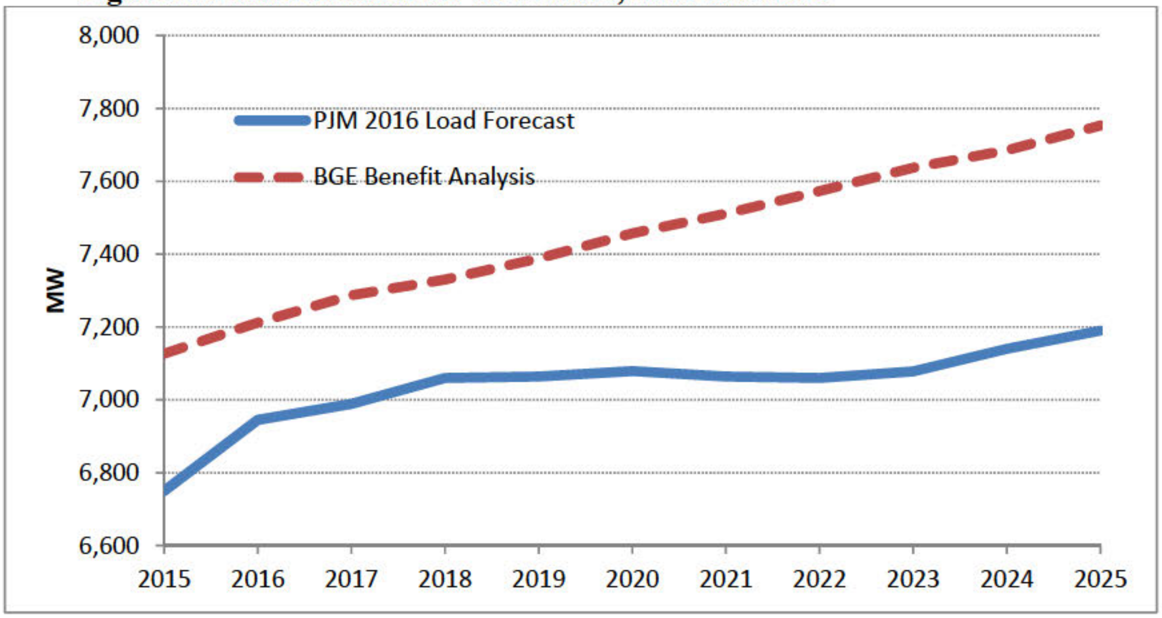
Q: What problems did you identify in BGE's estimates of peak reductions from its programs?

A: BGE uses an outdated forecast of load growth, and biases the analysis of SER saving by ignoring the free riders in the program.

Q: Please describe the update of load growth forecasts.

A: BGE's estimates of savings after 2014 are based on the PJM 2015 Forecast, which averages about 6% higher than the current 2016 forecast, as shown in Figure 1. The peak that BGE used for 2015 is about 5.6% higher than PJM's retrospective estimate of the BGE weather-normalized 2015 peak. Hence, all else equal, the avoided capacity-cost benefits would be about 6% lower than BGE estimated.

Figure 1: Peak Forecasts for BGE Zone, 2015 and 2016



Q: How did BGE misestimate the load reductions due to the SER?

A: BGE defined SER savings by inventing the concept of an SER "participant," which BGE defines as a customer who received a Peak Time Rebate for having lower energy use in the incentive period of an ESD than on the baseline days (Pinot Direct at 37, OPC DR 24-04). BGE estimates the SER savings as the sum of the reductions over all of the so-called participants, excluding the customers who increased usage. As a result, BGE's estimate of the SER savings includes reductions due to customers actually reacting to the $1.25/kWh incentive and also customers who just happened to have lower consumption that day for other reasons, but does not net out the customers who had higher consumption for other reasons.

Q: What factors might cause usage to vary from the baseline to the ESD?

A: Aside from weather and reaction to the SER incentive, the usage of any one customer varies from day to day due to all sorts of factors, including:

- Being out of town or out shopping in the incentive hours.

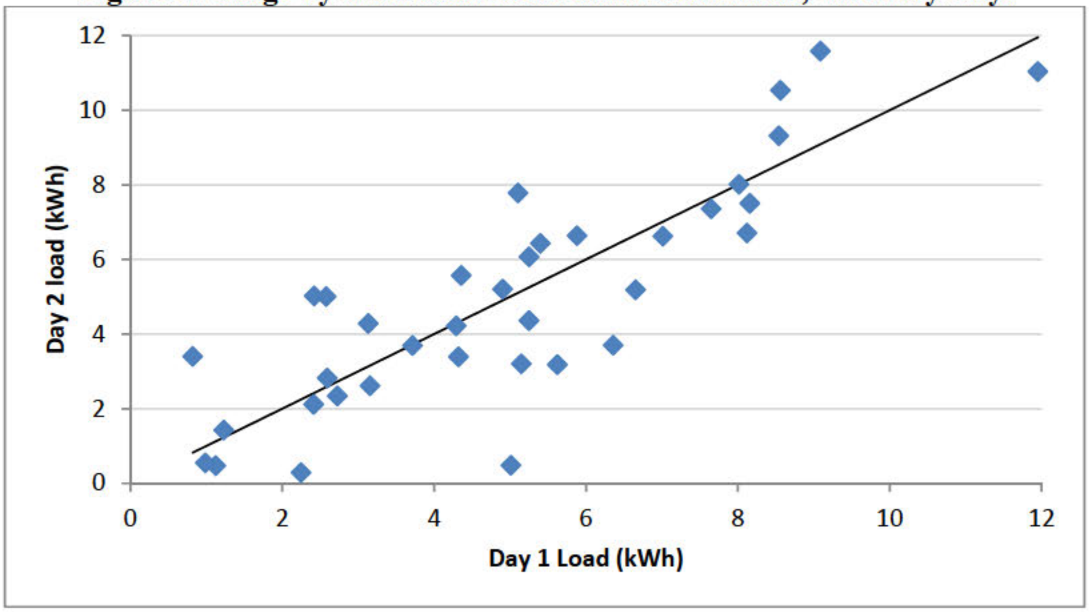
- Changing work schedules.
- Returning from vacation, and cranking up the air conditioner, doing laundry, etc.
- Hosting a party (with additional cooking and body heat load).
- Having visitors staying over, using more hot water, lighting and the like.
- Having an air conditioner or other appliance malfunction (increasing load) or stop functioning (decreasing load).
- Running a sump pump when the water table is high.
- Cleaning up after some major mishap or home-maintenance project (vacuuming, doing extra laundry loads, running dehumidifiers).
- Forgetting to close the blinds on the south-facing windows on a sunny day.

These events may occur on the ESDs, or on the baseline days.

Q: Can that random variability contribute significantly to overstating the apparent savings from the SER program?

A: Yes. Figure 2 shows the usage of individual residential customers (in the load-research sample of another utility) on two July days. Each point plots the usage of a particular customer on July 11 (on the horizontal axis) versus July 20 (on the vertical axis) in hour 17. The line shows where the points would have fallen if each customer used the same amount on each day. These 36 customers had no greater incentive to conserve on one day than the other; their aggregate usage on this particular pair of days varied by less than 1%.

Figure 2: Usage by Individual Residential Customers, Two July Days



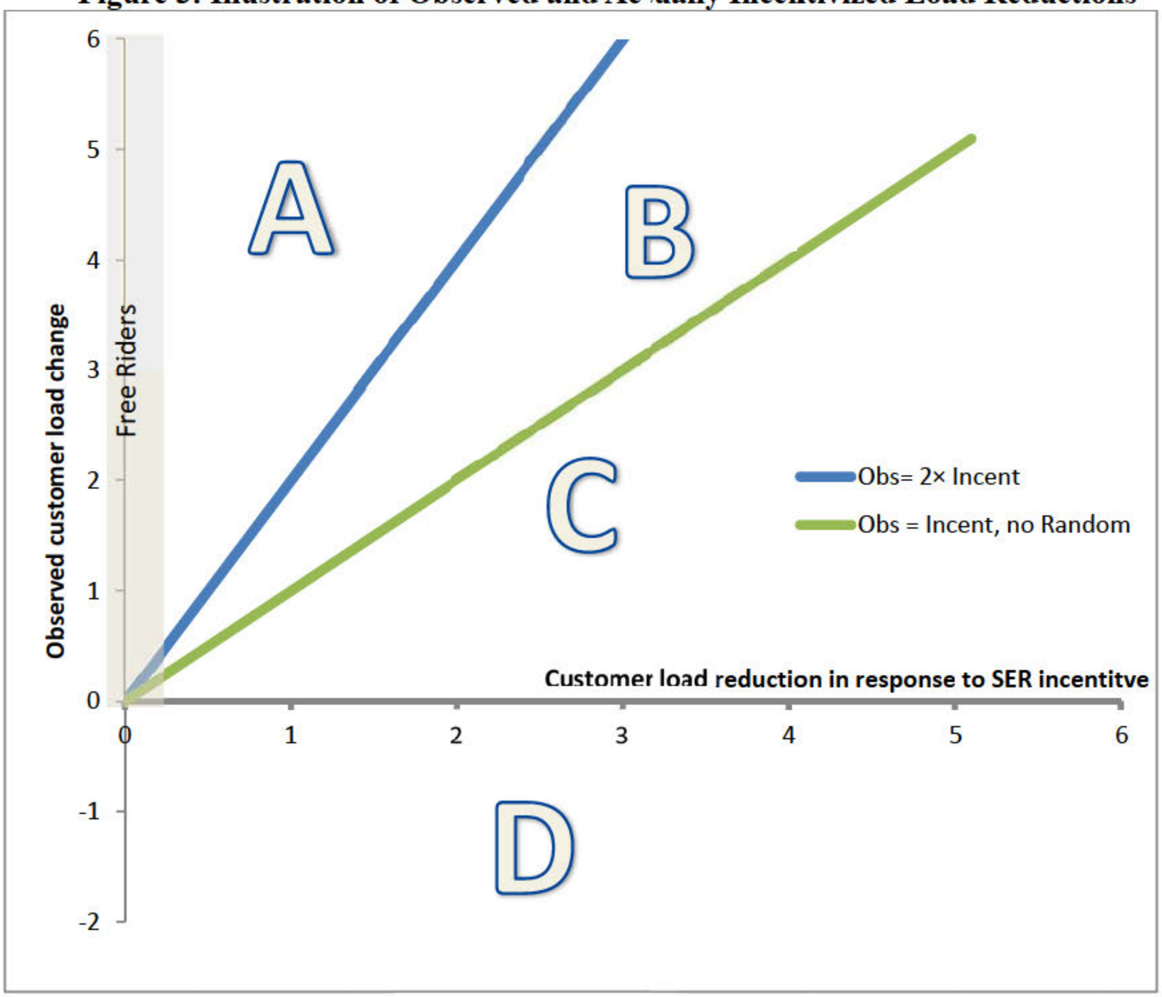
But several individual customers had usage that was much higher or lower on July 11 than on July 20; for one customer, the usage more than tripled from July 1 to July 20, while another used 90% less on July 20 than July 11. However, among the 20 customers whose usage decreased from July 11 to July 20, the average reduction was over one kWh, more than 11%. If this utility had implemented some program to encourage conservation on July 20, BGE's approach would identify the 20 customers whose load reductions as "participants," ignore the 15 customers whose load increased (and one whose load did not change), and conclude that the program resulted in a reduction of a kWh apiece for 56% of eligible customers.

Figure 3 looks at this issue another way, showing a plot of the reductions that would have occurred with the SER on the horizontal axis, observed reductions (the reductions due to the incentive plus the reductions or increases) on the vertical axis.[6] Each observed reduction (or increase, for

[6] I doubt that many people intentionally increase their usage to avoid getting the peak-time rebate.

points below the horizontal access) represents a real level of effort to respond to the program (from zero to full shutdown of the customer load), plus or minus the normal variability in usage. The BGE approach attributes to the SER all the savings in regions A (where the random reduction is greater than the intentional reduction), B (where the random reduction is smaller than the program reduction) and C (where there is a random increase, but not enough to offset the intentional reduction). The line between areas B and C represents the customers with no random load change.

Figure 3: Illustration of Observed and Actually Incentivized Load Reductions



Q: Do the normal random variations in usage balance out?

A: Not in BGE's approach. Area B (some level of real response, plus a smaller amount of random reduction) is balanced by Area C (some level of real response, minus a smaller amount of random increase). Area A (some level of real response, plus a larger amount of random reduction) is mirrored by Area D (some level of real response, minus a larger amount of random increase), but BGE omits area D. The extreme cases are the free riders—customers who do nothing to reduce their usage on the ESD—but have lower use on the ESD than on the baseline days.

Q: Can you estimate the extent to which BGE's selection of which customers to count as participants biases BGE's analysis of the SER savings?

A: My best estimate is that the actual load effect of the SER is the change in total load from all eligible SER-only customers, excluding the PR customers.[7] That correction would reduce BGE's estimates of the SER peak reductions by about 50% in 2014 and 30% in 2013 and in 2015 (which BGE uses as the basis for savings in all future years). 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.[8]

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[7] If more information were available about the variability of individual customer loads from day to day, a more complex analysis of the SER-induced changes would be possible, but there is not guarantee that greater complexity in the computations would result in a better estimate.

[8] The effects of my corrections are not additive, since many changes are multiplicative. As I discuss below, the SER load reductions have little if any effect on any of these cost categories, for reasons unrelated to the free riders.

2. PJM Forecasting and Capacity Obligations

Q: What was BGE's basis for its estimates of the effect of the program load reductions on zonal capacity obligation?

A: BGE assumed that the reduction in load obligation would be the average of actual SER load reduction in the hour ending at 5 PM (hour 17) in the two to four ESDs each year, plus the PJM reserve margin, would equal the reduction in capacity obligation six years later, phased in from years four through six. The basis for this set of assumption is "Mr. Pino's experience in PJM markets" (OPC DR 4-22).

Q: How are the capacity obligations of PJM zones determined?

A: For clarity, I will describe the process in terms of a particular capacity delivery year, starting in June of 2019. The PJM Resource Adequacy Planning Department conducts a series of regression analyses, for each load zone, in which the dependent variable is the daily peak load for the load zone, or its load coincident with the RTO load, or for other intermediate delivery areas, such as MAAC (the mid-Atlantic region, or roughly the pre-2002 PJM territory). The independent variables in the regressions are

- various binary (or dummy) variables for the month, day of the week, and holidays, and
- various combinations of weather measures (e.g., cooling degree days and a temperature-humidity index or THI), an economic index, and equipment efficiency measures, with many variable being the product of two or more of these parameters (e.g., CDD × economy × cooling efficiency). The effect of THI (either by itself or times the cooling-efficiency index) is split into four ranges (or splines), which for BGE are up to 65°, 65°–74°, 74°–83°, and over 83°.

The daily data cover the period from 1998 through the summer four years before the start of the delivery year, or August 2015 in our example. Those 6,400 observations are used to develop a regression equation for predicting (among other loads):

- PJM daily peak hour for various dates and weather conditions, given projected economic and efficiency trends.
- BGE load in the PJM daily peak hour.

For the 2016 Load Forecast Report, PJM computed the RTO daily maximum loads for 273 variations of historical weather patterns, and identifies the peak load for each variant, and identifies the median peak for the delivery year (e.g., the summer of 2019). The forecast is used to determine the required reserve margin, and hence the total capacity obligation. The BGE zonal capacity obligation is determined by the forecast of its contribution to the PJM peak load, plus the reserve margin resulting from the intersection of the VRR and the supply curve. Thus, the critical question is the extent to which reducing BGE load in particular hours reduces PJM's forecast of BGE load at future peaks.

Q: What reductions in post-2012 loads would affect the forecasts of PJM's peak load, the reserve requirement, and BGE's share of the capacity obligation?

A: That is a complicated issue.

Load reductions in the majority of the 365 observations for each recent year would tend to reduce the coefficients of variables that have been higher in the recent years than in previously years, such as the composite variables that include the rising quarterly economic index, partially offset by the declining indices for energy intensity. Those changes might tend to reduce the load forecast, since PJM expects the past trend in the indices to continue.[9]

Reductions in most of the days in a month will tend to reduce the binary variable for that month, and hence forecasts for peaks in that month. Since each month has over 500 observations in the data base, reductions phasing in starting in 2013 (and reflected in the BRA forecasts for the capacity years starting in 2017) would have only a modest effect in forecasts until long after 2020.

Similarly, reductions in most of the occurrences of a particular weekday will tend to reduce the binary variable for that weekday, and hence forecasts for peaks for that weekday. Since each weekday has over 900 observations in the data base, reductions phasing in starting in 2013 would have only a modest effect in forecasts for 2020.

Reductions that primarily occur in the worst weather conditions will tend to reduce the coefficient on the weather variables. Since there are so many hot summer days in the historical data, many years of load reductions would be needed to change the projections.[10] To further complicate the situation, if a load reduction occurs at the lower end of a THI spline, it will tend to increase the coefficient for that THI range; if the load reduction occurs on a day at the high end of a range, it will tend to decrease the THI coefficient.

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[9] The variable that includes the economic index and the index for cooling-equipment efficiency also includes the daily cooling degree days, further complicating predictions about the effect of DR load reductions in mild weather.

[10] This dilution effect is similar to the effects for the month and weekday binary variables, but more difficult to characterize, due to the multiplicity of weather measures and the range of values for each.

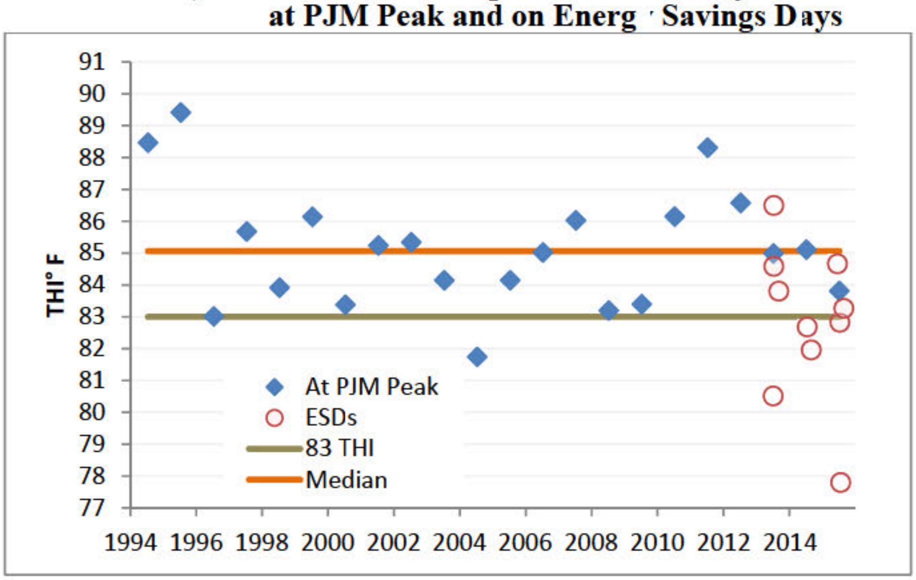
Q: What THI values have prevailed in Baltimore at the PJM annual peaks?

A: At OPC's request, PJM provided those data, which are shown in Figure 4. Most of the peak days had THI values in the top spline of the PJM model, over 83°F. The median (and average) THI at peak was 85.1°F.

Q: What were the THI values at the time of the PJM peak on the Energy Savings Days?

A: Figure 4 also shows those values, which I computed from National Weather Service data.[11] Of the ten ESDs, five days were in the top spline and only one was above the median. Overall, the SER and PR load reductions would tend to increase the coefficient of the THI variable for the temperature range in which the median peak used in the capacity-auction forecasts would tend to occur.

Figure 4: Baltimore Temperature-Humidity Indices at PJM Peak and on Energy Savings Days



[11] The ESD points shown are for hour ending 17; when the PJM or BGE peak fell on another hour, the THI was generally even lower.

Q: What information has BGE provided regarding the PJM's forecasting methodology for the peak load forecast?

A: BGE has provided no information on the forecast, other than a cite to PJM's Manual 19, "Load Forecasting and Analysis" (OPC DR 4-21), cannot determine how the load reductions from the SEM and the non-cleared reductions from the SER affected PJM's forecast for the BGE zone or capacity obligation (OPC DR 16-11), "does not have access to the data PJM used in developing the forecasting equations" (OPC DR 17-7a), does not understand how PJM projects weather-normalized load (OPC DR 16-10), and cannot determine how the PJM forecast would have been different without the SER and SEM programs (OPC DR 17-7b).

Q: What do you conclude from your review of the PJM forecasting model and the BGE program load effects?

A: 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 assumes.

3. Coincidence of Demand Reductions with Peak Conditions

Q: When do BGE's programs reduce demand?

A: That varies among the three programs. The SER provides a strong price signal to reduce load on Energy Saving Days in a six-hour period (hours ending 1400 through 1900) and shift load from that period to earlier and later hours; BGE alerts customers the day before. The PR program allows BGE to cycle participants' air conditioners when PJM declares a "Pre-Emergency

Mandatory Load Management Reduction."[12] BGE assumes that the SEM (which relies entirely on customer reactions to improved information, without pricing incentives) reduces loads by an equal percentage in all hours of the year.

Q: Do these programs reduce demand at most of the hours that determine the total PJM capacity obligation and the portion of the capacity obligation that PJM allocates to the BGE zone?

A: No. Each year, some 120 daily summer peaks contribute to the summer peak-load forecasts. The SER and PR programs reduce loads on only a few days in each summer. BGE called SER Energy Savings Days on four days in 2013, two days in 2014 and four in 2015. Table 2 lists the Energy Saving Days that BGE selected in 2013, 2014, and 2015. (OPC DR 4-3)

Table 2: Energy Saving Days

7/10/13
7/17/13
7/18/13
9/11/13
7/23/14
9/5/14
6/23/15
7/21/15
7/29/15
9/3/15

BGE operated the PR air-conditioning cycling program for the SER ESD hours and also for five hours on 7/19/13 and two hours on 6/15/15, (OPC DR 4-05).

[12] BGE can also cycle some water heaters, but the PR enhancements that BGE attributes to the smart meters **BEGIN CONFIDENTIAL** [redacted] END CONFIDENTIAL (OPC DR 17-5).

As shown in Table 3, BGE has not particularly operated the SER on days with the highest loads.[13] In 2013, BGE called an ESD on the peak day in the BGE zone, MAAC and PJM. But BGE missed the highest-load day in the other two years and the second-highest day in all three years, by all measures. Half of the ESDs were not even in the top five.[14]

Table 3: Loads on Energy Saving Days

	BGE Load		MAAC Load		PJM Load	
ES Day	**Rank**	**% of Max**	**Rank**	**% of Max**	**Rank**	**% of Max**
7/10/2013	16	85%	11	86%	12	85%
7/17/2013	3	96%	3	96%	3	97%
7/18/2013	1	100%	1	100%	1	100%
9/11/2013	4	95%	6	93%	6	92%
7/23/2014	5	95%	3	97%	20	94%
9/5/2014	18	90%	13	89%	5	98%
6/23/2015	3	97%	3	96%	7	96%
7/21/2015	13	91%	14	91%	23	92%
7/29/2015	39	82%	5	95%	4	99%

Q: Do you have any specific information about the effect of the SER on BGE's capacity obligation?

A: Yes. At the OPC's request, PJM reran its models from the 2016 Load Forecast Report with daily load increases (on the ESDs) to take out BGE estimates of SER savings, approximately a linear phase-in of savings from 2013 through 2015. For every megawatt added to the actual loads on the ESDs in 2013, the PJM model increased the forecast of BGE's 2019/20 peak by only about 0.03 MW and the PJM peak by about 0.04 MW. In contrast, BGE assumed that one megawatt of load reduction in 2013 would reduce the PJM forecast for BGE's 2019 peak by one megawatt, and the incremental

[13] I used the PJM data on unrestricted load (before demand response). Those data are not yet available for September 2015, so the table does not include September 3, 2015.

[14] BGE's record of selecting the hottest days is similarly poor.

increases in 2014 and 2015 would add 0.66 MW and 0.33 MW to the 2019 forecast, respectively, so BGE would expect that a linear phase-in of the SER savings would reduce the 2019 forecast by two megawatts for each megawatt of 2013 load reduction. In other words, 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.

Q: What about the SEM program?

A: BGE assumes, without any evidence, that the SEM reduces loads by the same percentage at the RTO weather-adjusted peak as for annual energy.[15] Navigant has repeatedly suggested that BGE test this assumption against hourly data (Staff DR 8-24, Attachment 1 at 17 and Attachment 2 at 31), yet BGE has not done so (OPC DR 16-14b). If this unsupported assumption is true for all hours, the SEM would reduce all the coefficients to varying extents, for every month, weekday, and weather condition, and for the economic index.

Even so, the SEM was in operation for only two of the eighteen years from which PJM drew data for the 2016 forecast that will drive the 2019/20 BRA, and only one of sixteen years for the 2015 forecast.[16] For the last year whose loads affect capacity obligation in BGE cost-effectiveness analysis (2021, which will influence the 2022 forecast that will determine the 2025/26 capacity obligation), the SEM will have been in place for eight of the 24

[15] Staff DR 8-24 Attachment 3 shows considerable variability in savings among months, but does not provide any data on savings by time of day or load level.

[16] The regressions use data from January 1998 through the summer of the previous year (e.g., August 2015 for the 2016 forecast). PJM does not have any plans to change the 1998 starting point for the regression.

years used in the analysis. The claimed SEM peak reductions (if they occur) would reduce BGE capacity obligation and Maryland capacity price much more slowly than BGE projects.[17]

Q: Did you ask PJM to rerun the forecast model for reductions similar to those BGE claims for the SEM?

A: Yes. OPC asked PJM to reduce the historical daily peaks by 1% in 2013, 1.4% in 2014, and 1.5% in 2015 and rerun the forecasting model. PJM found that this adjustment reduced the forecast peak for 2019 by 0.4%, while BGE would have predicted a reduction of 1.3%. While not as dramatic as for the SER type of reduction, this result indicates that BGE is overstating the reduction in capacity obligation from the SEM by a factor of three.

C. Capacity Price Mitigation

Q: How does BGE estimate the effect of the programs on the capacity prices paid by consumers.

A: For the SER and PR resources that have cleared (or that BGE expects to clear) in the PJM capacity markets, BGE calculates the benefit to customers for each year as the product of

- the cleared program capacity, adjusted for a PJM-mandated reserve margin,

[17] In addition, the benefits from the SEM can only be attributed to the smart meters if the savings from the home energy reports require the smart meters, an issue addressed in the testimony of Mr. Chang. BGE acknowledges that "energy savings from Home Energy Reports [are] achievable outside of the Smart Grid Initiative,…but customers are able to achieve a much greater level of energy savings as a result of the Smart Grid Initiative." (Staff DR 8-25). Given this admission, at least some of BGE's estimated SEM savings should be excluded from the smart-meters benefit.

- PJM's forecast in each BRA of Maryland load (BGE, plus the Maryland portions of Potomac Edison, PEPCo and Delmarva) at the time of the PJM peak three years later,[18] and
- A coefficient that BGE presents as representing the change in the BRA clearing price for premium capacity in $/MW-day per megawatt of low-cost capacity added to the supply curve in the BRA.

For load reductions that BGE does not bid into the BRA (the estimated SEM peak reduction and a measure of SER load reduction, net of the cleared SER capacity), BGE uses the same parameters as for the cleared capacity, but applies the same four-year lag and three-year phase-in as for avoided capacity cost (as I discuss in Section III.B).

BGE assumes that the effects of price mitigation from cleared supply last four years, reflecting the structural response of the market to lower prices (Pinot Direct at 45), but that the effects of price mitigation from load reductions are permanent (or would at least last through 2025, for a life of up to nine years). This parameter is difficult to directly observe or estimate and BGE's estimates fall in the range I have seen elsewhere. I do not challenge BGE's estimates for the purpose of this review, but I do not endorse the use of different lives for the demand- and supply-side effects.

Q: What problems have you identified in BGE's estimate of capacity price mitigation?

A: I have identified five errors in BGE's analysis. First, as I explained in Section III.B, the SER load reductions will not substantially affect the amount of

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[18] BGE omits the BEGIN CONFIDENTIAL [redacted] load in [redacted] through [redacted] when BGE and the rest of MAAC cleared at higher prices than [redacted], and [redacted] load in [redacted], when [redacted] separated from the rest of the system. END CONFIDENTIAL

capacity that PJM acquires, so those reductions will have no effect on capacity prices. PJM's modeling of a SEM-like load reduction also indicates that the SEM will affect the PJM capacity requirement and the price of capacity much less than BGE assumes.

Second, the load forecast that BGE uses to estimate the amount of capacity that Maryland customers will bear (and hence the effect of a price reduction) is much higher than PJM's current forecast.

Third, BGE assumes that prices for Delmarva will always be affected by BGE loads in future BRAs.

Fourth, the coefficients that BGE uses to convert load reductions and cleared resources to price reductions is grossly overstated.

Fifth, the price reduction from adding the BGE program demand resources to the capacity auctions are often less than the reduction from adding generation or other premium resources.

Q: How do the current PJM load forecasts differ from those used in BGE's analysis?

A: As shown in Figure 1, the load forecast for BGE is now lower than BGE used in its benefits analysis. Since BGE represents over half of the Maryland load, the decline of BGE's load forecast significantly reduces the Maryland load forecast. In addition, the loads projected in PJM's 2016 Load Forecast Report for 2025 have fallen 4% for PEPCo, 11% for Delmarva, and 2% for Potomac Edison, compared to the 2015 report. Overall, the Maryland forecast appears to have fallen about 5%, which would proportionally reduce the capacity price benefit.

Q: How are capacity prices for the Delmarva zone affected by changes in BGE load?

A: That varies from auction to auction, depending on supply and demand conditions in the zones. The EMAAC LDA, including Delmarva, has separated from SWMAAC and the RTO in three of the last seven BRAs, including the most recent auction (2018/19). **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** in 2018/19, since reductions in BGE load would not have allowed any additional capacity to be supplied to Delmarva, so Delmarva's capacity price would not have declined in response to lower forecast BGE load. In most situations in which no specific information is available, BGE's analysis **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** If BGE had used that approach, it would have assumed that **BEGIN CONFIDENTIAL** [redacted]. **END CONFIDENTIAL** Instead, BGE assumes that **BEGIN CONFIDENTIAL** [redacted]. **END CONFIDENTIAL** A more reasonable estimate might be that EMAAC would separate from the RTO in half the years, so the average load affected by a reduction in BGE load would be about 5% lower than BGE has assumed.

Q: What information was BGE able to provide about the operation of the PJM capacity markets?

A: BGE indicated that it does not know how its loads affect its forecast or the effects of various types of supply (historically, Annual, Extended Summer, and Limited; in 2018/19, Capacity Performance and Base) on market-clearing prices or charges to load (OPC DR 4-19, DR 4-20, DR 4-21, DR 4-25).

Q: How did BGE estimate the capacity-price mitigation coefficient?

A: BGE assumes that the reduction in price in $/MW-day per megawatt of load reduction or cleared capacity will be 50% of the slope of the steeper portion of the Variable Resource Requirement (VRR) curve. BGE presents no evidence to support this value, and has conducted no supporting analysis (OPC DR 4-27).

Q: What is the origin of this approach?

A: The MEA invented it in the EmPOWER consultation process, also without any analytical support, other than the fact that it is half-way between zero and the slope of the VRR. Excerpts from the EmPOWER filings are attached as Exhibit PLC-4.

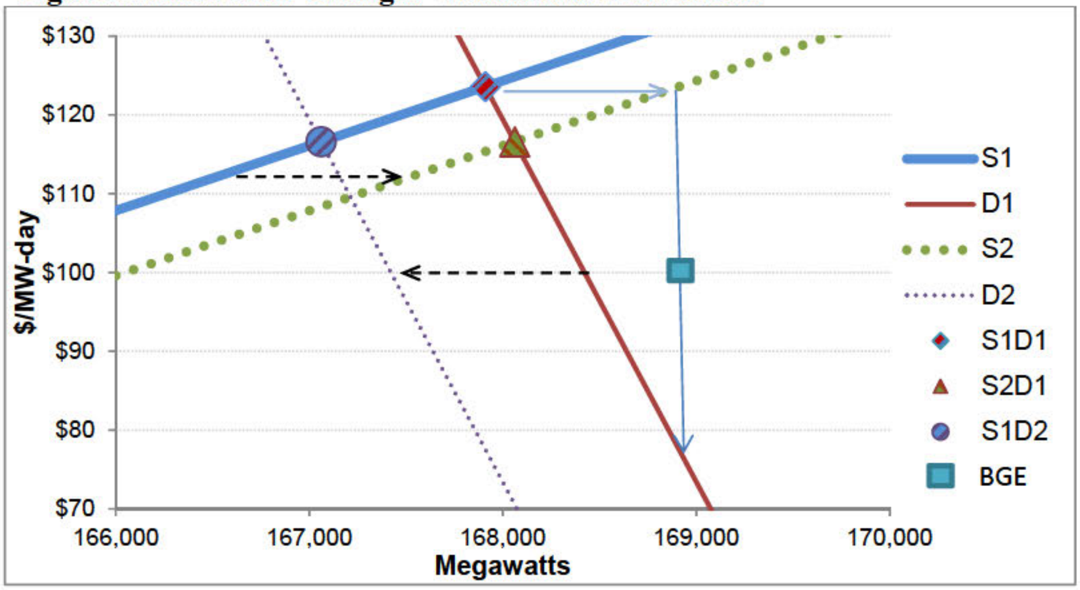
Q: What market dynamics should the capacity-price mitigation coefficient reflect?

A: The $/MW-day/MW coefficient should reflect the operation of the PJM capacity auction. Figure 5 illustrates the operation of the RPM market, or any other simple matching of supply and demand.[19]

Figure 5 illustrates the effect of adding 1,000 MW of peak reduction to the RTO market as an increase of supply (shifting the S_1 supply curve to the S_2 supply curve) or a decrease in demand (shifting the D_1 VRR curve to the D_2 VRR curve). The dashed lines show a 1,000 MW shift in the supply curve to the right, or the demand curve to the left.

[19] For ease of presentation, this example ignores the multiple types of capacity acquired at different prices in some PJM auctions, as well as the multiple pricing zones. As I discuss below, the capacity product that BGE has bid into some of the auctions has little or no effect on the price paid for most of Maryland's capacity obligation.

Figure 5: BRA Price Changes--Actual and BGE Model



In addition to the actual clearing price (point S_1D_1), Figure 5 shows the effect of shifting the supply curve 1,000 MW to the right (point S_2D_1, reflecting addition of 1,000 MW of low-price premium capacity into the auction) and the effect of shifting the demand curve 1,000 MW to the left (point S_1D_2, reflecting 1,000 MW reduction in the demand curve from reflecting the same amount of reduction in the forecast driving the demand curve). In each case, the 1,000 MW shift reduces the market-clearing price by about $7/MW-day.

The BGE method, on the other hand, would estimate a $23 reduction in price, also shown in Figure 5. The BGE method is uniformly biased upward.

Q: How should this coefficient be estimated?

A: There are two viable approaches to modeling the auction:

- Using available data on the VRR and the supply curve to find the new market-clearing prices following a load change. Since PJM released only graphic representations of the supply curves by zone and (where relevant) resource type for the 2014/15, 2015/16, and 2016/17 BRAs, this method requires some approximation and it is limited to those three years.[20]

- Relying on the sensitivity analyses performed by PJM following the 2014/15, 2015/16, 2016/17, 2017/18 and 2018/19 BRAs. Since PJM has all the price bids and all the rules it uses in setting the market-clearing price in each zone, these results should be very accurate. Unfortunately, the sensitivity studies do not cover all interesting types of load reductions (in this case, a reductions in BGE load and additions of demand response in the BGE zone) and are generally for changes larger than the effects BGE claims for its programs.

Q: Has the first method been implemented?

A: Yes. As discussed in the MEA's EmPOWER 2015–2017 Cost Effectiveness Framework and demonstrated in the VRR Curve Capacity DRIPE table (attached as part of Exhibit PLC-4), MEA estimated the slope of the Variable Resource Requirement (VRR) curve (the administrative equivalent of a demand curve) from PJM filings of Planning Period Parameters documents, and the supply curve from graphics that PJM has provided for three BRAs.[21] Table 4 compares the coefficients used by BGE for those years with the coefficient that results from determining the new equilibrium price. I present

[20] BGE does not have any information regarding the actual slope of the capacity supply curve. (OPC DR 4-28)

[21] 2014/2015 Base Residual Auction Report Addendum, 2015/2016 Base Residual Auction Supply Curves, and 2016/2017 Base Residual Auction Supply Curves, all available at www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/.

only the MAAC results, since BGE models only the effects of BGE load changes on prices in MAAC for those years.[22]

Table 4: Comparison of BGE and Equilibrium Price Response to Load Reductions (**$/MW-Day/MW**)

	2014/15	2015/16	2016/17
BGE Approach	[redacted]	[redacted]	
New Equilibrium	$0.0338	$0.0266	$0.0167

NOTE:The Highlighted numbers Are CONFIDENTIAL

A realistic assessment of the change in prices, using only the VRR and supply-curve data that PJM has released, would result in price reductions about **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** less than BGE assumed for 2014/15, **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** for 2015/16, and **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** for 2016/17.

Q: Do the PJM sensitivity analyses provide a more comprehensive view of the capacity price-mitigation effects than the graphical analysis whose results you present in Table 4?

A: Yes. The results in Table 4 rely on visual estimation of the supply slope from a graph that PJM manipulates to obscure individual bids, are available for only three years, and cannot directly estimate the effect of BGE load and resources on prices for Potomac Edison or Delmarva, in the years in which price separate.

[22] This treatment ignores the effect on Potomac Edison customers resulting from the effect of MAAC load and supply on the RTO clearing price.

The PJM sensitivity analyses represent PJM's hypothetical reruns of the BRA, adding or subtracting various amounts of low-price capacity in one or more LDAs.[23] The results should reflect all the complexities of the operation of the PJM capacity auctions, including the VRRs, supply curves, and constraints on Limited and Extended demand resources in each of the modeled zones and LDAs. Table 5 shows the $/MW-day change in price in various LDAs for subtracting a MW of supply in the BGE zone.[24] Table 5 shows the type of capacity removed from the bottom of the supply curve, the smallest LDA containing BGE for which supply decreases were modeled, the size of the decrease, and the increase in price of the premium supply (Annual Supply in the first four auctions, Capacity Performance in 2018/19) divided by the reduction in supply ($/MW-day/MW).[25]

Table 5: Summary of PJM Sensitivity Analyses for Supply Decreases

Year	Type of Supply Removed	Modeled LDA	MW Δ	Price Change ($/MW-day) for 1-MW Δ in BGE Zone		
				RTO	**EMAAC**	**SWMAAC**
2014/15	Annual	SWMAAC	–500	0.0252	0.0165	0.0165
	Limited	SWMAAC	–500	0.0050	-0.0048	-0.0048
2015/16	Annual	SWMAAC	–750	0.0027	0.0367	0.0367
2016/17	Annual	SWMAAC	–750	0.0030	0.0140	0.0140
2017/18	Annual	MAAC	–3,000	0.0094	0.0094	0.0094
2018/19	Performance	MAAC	–3,000	0.0049	0.0045	0.0049

In the first three relevant years, PJM modeled supply changes in the SWMAAC region (among others); in the last two years, PJM modeled supply

[23]The sensitivity analysis for each BRA is available at www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx, under the drop-down list for that BRA.

[24]Where PJM modeled multiple changes (e.g., ±2,000 MW and ±4,000 MW), I use the slope for the smaller range, to better represent the scale of energy-efficiency programs.

[25] The premium supply represents most of the capacity procured in each year, and BGE uses the premium-supply price in its analysis of capacity price suppression.

changes distributed among the zones of MAAC, but not for SWMAAC alone. For 2014/15, PJM modeled reductions in both annual supply (generation and some demand resources) and Limited Demand Resources.

The annual PJM sensitivity scenario reports are provided in Exhibit PLC-5 and my computation of the relevant price changes are shown in Exhibit PLC-6.

Q: Did BGE explain why it did not use the results of the PJM sensitivity analyses?

A: No, only that it relied on the Commission's acceptance of the half-of-VRR value for screening of the 2015–2017 EmPOWER Maryland programs (OPC DR 4-25 and DR 4-26).[26] Since the SER and PR load reductions are very different from the energy-efficiency load reductions modeled in the EmPOWER Maryland analysis, and bid into the auctions as an inferior product, and a majority of the capacity revenue is from auctions that have already occurred, the EmPOWER analysis is not applicable to the cost-benefit review of the smart meters. BGE admits that it "does not know how the various pricing of DR programs are affected. BGE relied upon EmPOWER MD Commission-approved mitigation methodology." (OPC DR 4-25)

Q: What is the significance of the negative signs in the "Limited" line for 2014/15?

[26] The Commission's order accepted this approach for just one EmPOWER program cycle and noted that the EmPOWER "DR IPE methodology may be revisited in conjunction with subsequent program cycle planning following completion of additional analyses as recommended by Staff." (Order No. 87082, Case Nos. 9153, et al., at 13) The current proceeding does not concern the evaluation of the EmPOWER programs, and my testimony provides additional analyses.

A: The PJM sensitivity analysis indicates that removing 500 MW of Limited Demand Resources reduces the Annual Supply price for the RTO, but increases that price for SWMAAC and EMAAC. The reduction in Limited Resource supply increases the price of Limited Resources in all three LDAs (by about $0.0047/MW-day per MW), but Limited Resources are only about 15% of SWMAAC supply and 7% of EMAAC supply.

Q: Is it surprising that removing Limited resources does not increase the price of Annual Resources?

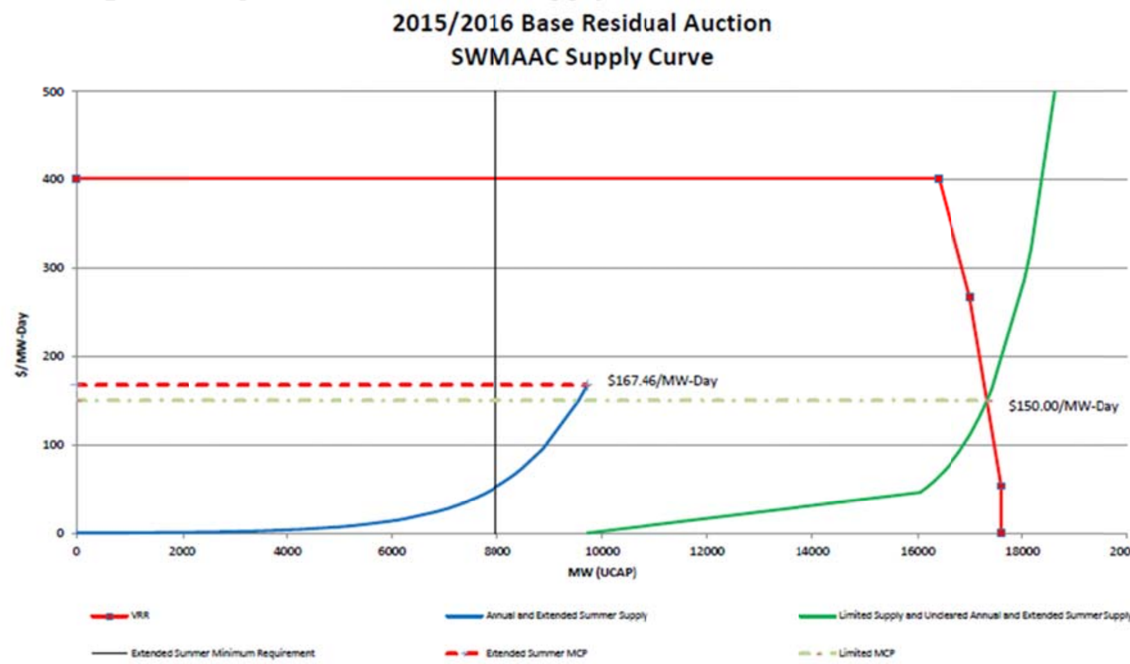
A: No. I would expect that, whenever Limited resources cleared at a significantly lower price than Annual resources, reducing the supply of Limited resources would increase only the Limited price and not the Annual price. PJM restricted the amount of Limited resources it would allow to clear in the market (for the RTO and for various LDAs).[27]

Figure 6 illustrates the split clearing for Limited resources in 2015/16. From that graphic, it appears that a couple hundred megawatts of Limited resources would need to be withdrawn before the price of the Annual resources would rise at all. Of the 2015/16 cleared SER capacity of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** MW, removal of only a small part, perhAP the last 40 MW) would contribute to raising the Annual price. The BGE programs were bid as Limited resources in 2014/15 and 2015/16, and cleared at prices below Annual resources. In 2018/19, BGE's programs were Base resources, which cleared far below the price of the

[27] PJM imposed limits on the amount of Extended Summer resources, but those constraints do not appear to have been binding in the years and zones of interest in this analysis. In the 2018/19 BRA, PJM imposed similar constraints on Base supply, resources that do not meet the Capacity Performance requirements.

performance capacity. Only in 2016/17, when all resources cleared at the same price, and 2017/18, when BGE's programs cleared as Extended resources at the same price as Annual resources, would the programs have clearly reduced the price for the dominant class of capacity resources.[28]

Figure 6: Separation of Limited Supply Price



PJM has not released supply curves for 2018/19, but the SWMAAC clearing price for Base supply (including the SER and PR capacity) was 60% lower than the price for Capacity Performance, so it is unlikely that removing the **BEGIN CONFIDENTIAL** [redacted] MW **END CONFIDENTIAL** of cleared SER and PR capacity from the 2018/19 BRA (out of the 1,760 MW of Base resources that cleared in SWMAAC) would affect the Annual price.

Q: Is the change in price the only effect of changing the amount of demand resources that BGE sells into the capacity market?

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[28] BGE identifies the type of capacity for which it offered the programs in OPC DR 4-09, but omitted 20116/17, which I determined from OPC DR 17-3.

A: No. PJM developed the VRR to increase the amount of capacity procured as price falls and decrease the amount procured as price rises. If BGE had not bid the SER and incremental PR into the capacity market, some prices would have been higher, but the amount of capacity procured and hence the capacity obligation for BGE, PEPCo and (in some years) Delmarva and Potomac Edison would have been lower. BGE has not taken this effect into account and "does not have an estimate of the effect its DR capacity bids have on increasing the cleared capacity in the PJM RPM auctions" (OPC DR 4-18).

Q: What are your best estimates of the price-mitigation coefficients applicable to reductions in peak load and to demand response bid into the capacity auctions?

A: Table 6 summarizes my recommendations, before any adjustment for the offsetting increase in capacity obligation as prices fall. Load reductions would have the effects summarized in Table 5, while the cleared resources provide less (or negative) benefit in 2014/15 and no benefit in 2015/16 and 2018/19. Cleared demand resources have full benefits in 2016/17, when the Limited resources cleared at the same price as other resources, and 2017/18, when BGE bid the programs as Extended Summer resources, which cleared at the price of Annual resources.

Table 6: Effect of BGE Demand Response on Capacity Prices ($/MW-day/MW)

Year	BGE modeled as part of	Load Reductions			Cleared Demand Resources		
		PE	DPL	PEPCo + BGE	PE	DPL	PEPCo + BGE
2014/15	SWMAAC	0.0252	0.0165	0.0165	0.005	-0.0048	-0.0048
2015/16	SWMAAC	0.0027	0.0367	0.0367	–	–	–
2016/17	SWMAAC	0.0030	0.0140	0.0140	0.0030	0.0140	0.0140
2017/18	MAAC	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094
2018/19	MAAC	0.0049	0.0045	0.0049	–	–	–

Some of these corrected coefficients are higher than BGE's estimates: I include price benefits for **BEGIN CONFIDENTIAL** [redacted]**,END CONFIDENTIAL** all of which BGE omits. The Delmarva coefficient for 2018/19 reflects the fact that PJM modeled simultaneous reductions in all parts of PJM, including EMAAC; a reduction just in the BGE zone would almost certainly have a much smaller effect on the price in EMAAC, which was 37% higher than the SWMAAC price.

Q: What effect does this last correction have on BGE's claimed benefits?

A: The corrected price-mitigation coefficients decrease BGE's claimed price-mitigation benefits by over $170 million, even without reducing the claimed SER load reductions, reducing the program effects on capacity obligation, updating the load forecasts, or incorporating the increased capacity obligation due to reduced price.

Q: Please summarize your review of the effect of the BGE programs on capacity prices.

A: The SER and PR programs are unlikely to produce any meaningful capacity-price benefits. The SEM may produce some price benefits, but substantially less than BGE assumes, since BGE overestimated the sensitivity of the load forecast to recent load reductions and the response of price to reductions in forecast load.

IV. Claimed Transmission and Distribution Benefits

Q: What problems have you identified that are common to BGE's estimates of transmission and distribution benefits?

A: I have identified four such problems:

- BGE's inability to identify any projects avoided in the years in which BGE claims large avoided capital costs.
- BGE's inability to produce any documents demonstrating that its T&D planners actually reflect the SER and PR load reductions claimed in this case.
- The mismatch between the timing of the SER and PR load reductions and the timing of the peak loads driving T&D investment.
- BGE's failure to annualize the avoided capital costs.

Q: What is your basis for saying that BGE cannot identify any projects avoided in the years in which BGE claims large avoided capital costs?

A: BGE was asked to identify those projects in OPC DR 4-46 and OPC DR 16-9 for transmission and OPC DR 4-42 and OPC DR 16-18 for distribution, but was unable to identify any such projects. BGE claims that **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** million in transmission projects were permanently avoided in 2013, another **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** million in 2014, and **BEGIN CONFIDENTIAL** $[redacted] **END CONFIDENTIAL** million in 2015, for a total of **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** million, yet it cannot list a single project that was deferred, let alone avoided. The same is true for distribution: BGE claims that **BEGIN CONFIDENTIAL** $[redacted] **END CONFIDENTIAL** million was avoided in 2013, **BEGIN CONFIDENTIAL** $[redacted] **END CONFIDENTIAL** million in 2014, and **BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL** million in 2015, but cannot tell us what substation investments were avoided. These requests did not ask for reexamination of projects from the distant past, or speculation about the future, but about the last three years of investments.

This is particularly striking, since in order to avoid T&D investments, BGE would need to explicitly adjust load forecasts to account for the SER and PR loads, which do not occur in most hours, and forecast the resulting load at the time of the line or substation peak. BGE would need to forecast the effect of SEM on load trends, since BGE estimates that SEM would have started reducing loads only in 2014, by which time the 2014 T&D additions and much of the 2015 additions would have been committed. If BGE has actually adjusted all those forecasts and changed its investment plans, it should have some documentation of those decisions. The absence of evidence is, in this case, very suggestive of the absence of any investment deferrals.

Q: Why do you say that BGE was unable to provide any documents supporting its claim that it reflects load reductions from the programs in its T&D planning?

A: BGE claims that it "estimates load growth based on applications for new services, historical trends for existing customer load growth and expected magnitude of demand response through programs such as PeakRewards and BGE Smart Energy Rewards. This load growth is allocated to each distribution circuit for each geographic area and then rolled up through substations and transmission lines" (Staff DR 8-42) When asked for "any documents developed in 2013 through 2015 that show" these steps, BGE simply repeated its claim that it follows those steps, without providing the actual computations, reports or other documents that it would have needed to produce if it were really using the claimed load reductions in T&D planning. (OPC DR 16-17) BGE would be imprudent if it actually counted on the unreliable SER load effects in T&D planning; I hope that its T&D planners are more realistic than the BGE staff who prepared the smart-meter justification and the responses cited above.

Q: What is the problem with BGE's failure to annualize the avoided capital costs?

A: BGE assumes that customer rates are reduced by the entire capital cost in the year in which the programs result in incremental load reductions, mostly 2013–2015, rather than spreading the costs over the life of the deferred investments.

> BGE did not apply a carrying charge. BGE estimated avoided capital expenditures, not avoided revenue requirements due to avoided capital expenditures. This method is consistent with all other avoided capital treatment used by BGE in its cost-effectiveness analysis. (OPC DR 4-30)

This treatment is incorrect in three ways.

- This method is not consistent with the treatment of other benefits, which are counted (more or less) as they would flow through to ratepayers, not in a lump sum when loads are reduced. In the case of T&D deferral, the avoided costs must recognize that the equipment will be more expensive when the deferral is over and the deferred projects are built.
- The benefits to ratepayers of avoided capital costs flow through to customers over the life of the avoided equipment, through charges for return, income taxes, and depreciation. Only a portion of the costs would flow through to customers during the analysis period that BGE has used.
- There is no assurance that any capital costs avoided in 2013 or 2014 will be avoided forever. Normally, avoided T&D costs are converted into a real-levelized stream of benefits, which can be credited to a program for

the period that the program reduces load. This treatment both annualizes costs and matches them to the savings over time.

- Customers have not received any benefits from the avoided capital in 2013 through 2015, since BGE has not filed a rate case. Any costs avoided in this period (and into 2016) have benefited BGE shareholders, not ratepayers.

The present value of the real-levelized cost would be about 70% of the 2013 deferred capital costs (assuming a life of 40 years) and 55% of the 2015 deferred capital costs; only about 45% of the capital cost deferral would flow through to ratepayers.

Q: Does BGE offer any regulatory support for T&D method?

A: Yes. BGE claims that "The assumptions [in Mr. Pino's testimony] to value the avoided transmission and distribution system are consistent with the Commission's July 16, 2015, EmPOWER Maryland Order No. 87082." (Staff DR 8-41) In fact, that Order does not mention or endorse any specific T&D values, and BGE's avoided T&D costs were only described in three paragraphs of the 97-page Exeter Associates report on "Avoided Energy Costs in Maryland." BGE admits that the alleged consistency was limited to the fact that "Order No. 87082 accepted the utilities' cost-effective screening for the EmPOWER Maryland plans" (OPC DR 14-04).

Not only did BGE's T&D estimates fly under the radar in the EmPOWER proceeding, BGE did not use in this proceeding the Exeter-reported values, and those values were used in estimating the benefits of energy-efficiency, not demand response. Also, Exeter reports that "BGE utilized a 'functionality discount factor' of 1.5 to take into account the fact that energy efficiency measures do not have the ability to be controlled locally to address specific local distribution feeder issues." (Exeter report at 31). BGE did not make that adjustment in this proceeding, so its distribution avoided costs are not consistent with those filed in the EmPOWER dockets.

A. Transmission

Q: What additional issues have you identified in BGE's estimate of the value of avoided transmission?

A: I have identified eight problems.

First, BGE computes the $/kW avoided cost from the total cost of its 250 kV and 500 kV transmission system, priced as if it were all constructed in 2015. This is a peculiar approach, since it includes costs back to 1971 and assumes that the incremental cost of serving increased load is the same as the average ratio of all existing costs divided by some measure of total load (or something similar). Normally, avoided transmission capital costs are estimated as the ratio of investment over some recent or forecast period, divided by load growth in that period.[29] BGE was not able to provide any evidence that the escalated cost of the legacy transmission system is typical of the types of transmission projects that would be avoidable by load reductions. In response to a request to an explanation of why the "transmission assets used in the analysis of avoided transmission costs are typical of costs that would be avoidable from the deployment of BGE's Smart Grid-enabled programs" (OPC DR 4-43), BGE simply refers to page 46 of Mr. Pino's testimony, where he says that "the replacement cost of

[29] Since BGE has not experienced any growth in weather-normalized peak load since 2008, it could either compute avoided transmission cost per MW from additions and growth in 1998–2008, or for the future, in which PJM expects BGE's loads to rise.

transmission assets contributing to import capability (500kV and 230kV systems) [divided by] the import capability of the transmission assets… represents the avoided cost per kW of the transmission import assets." In other words, when asked why BGE believes its approach is realistic, it replied with a description of its approach. Indeed, BGE volunteers that "Existing equipment cannot be avoided because it is existing equipment" (OPC DR -4-42), which applies to all the costs in its transmission and distribution computations.

Second, 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. In OPC DR 4-35, BGE acknowledges that "All 500kV and 230kV equipment is included in the analysis" but claims that all such equipment "contributes to import capability," without any explanation of how that could be true. BGE acknowledges that Calvert Cliffs connects to the 500 kV system and that Brandon Shores and Wagner connect to the 230 kV system (OPC DR 4-42).[30]

Third, BGE does not divide the costs of these facilities by the load in the BGE zone, but by the zone's import capability (OPC DR 4-36). This is a value computed by PJM, and BGE does not know how much, if at all, changes in load would affect the import capability or the need to increase that capability (OPC DR 4-39).[31] The list of planned projects listed by BGE (OPC

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[30] In this response, BGE describes only the equipment closest to the power plants, ignoring the long transmission lines connecting that generation to load.

[31] BGE explains its use of the import capability, rather than the usual peak load, as follows: "The analysis is estimating $ per kW cost of the 500kV and 230kV import system, therefore BGE finds it appropriate to use the cost of the system divided by import capability." (OPC DR

DR 4-40) does not identify any projects planned to increase import capability.

Fourth, BGE provided loads on each 230 kV and 500 kV transmission line for the Energy Saving Days and the January and March 2014 system emergencies (OPC DR 4-38, Attachment 3).[32] A majority of lines experienced higher loads in that winter period than on the Energy Savings Days in 2013 (56% of lines, 65% of capacity), and in 2014 (56% of lines, 68% of capacity), while 34% of the lines (and 36% of the capacity) had higher loads in the winter of 2014 than the summer of 2015. In a supplementary response, BGE specified the time at which each transmission line reached its peak load in 2013–2015; none of these peaks occurred on an ESD, less than 40% occurred in the summer, and only 5% occurred in the hours 14 to 19. And even those two summer afternoon peaks were at fairly low system load levels, when the BGE zonal load was at 54% and 75% of the 2015 peak. Reductions during the incentive hours on ESDs are unlikely to have affected transmission planning or costs.

Fifth, the load on any particular line can go down as the BGE zonal load rises. Using regression, I found that 35% of the lines had loads that were negatively correlated with the zonal load on the ESDs in 2013, while 37% were negatively correlated in 2015.[33] These sets do not overlap, so 72% of

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4-36) Since the 500kV and 230kV equipment provides services other than import, this explanation is far from convincing.

[32] There were 40 such lines in 2013 and 41 in 2014 and 2015. BGE provided data for hours ending 13 through 19 on each day (except for 9/11/13, for which BGE provided hours 13 to 18).

[33] I did not perform the same analysis for 2014, since BGE called only two ESDs and hence provided data for only 14 hours.

the lines had loads negatively correlated with the system in one year or the other.

BGE's transmission projects include costs driven by the loads of other zones and allocated to other zones. In allocating the costs of those projects among zones, PJM uses the same forecasting approach as it uses in the generation-capacity auctions. The SER and PR will have little effect on those forecasts, and the SEM (if it affects peaks at all) will only slowly change the regression equations. BGE cannot identify the hours whose loads affected the allocation of costs of any transmission projects to the BGE zone (OPC DR 16-9).

Sixth, BGE was unable to identify the type of load (by location or timing) for its past or projected transmission projects (OPC DR 4-44, OPC DR 4-45). Hence, BGE cannot know whether a transmission project would have been avoided by load reductions at the times and that the SER and PR reduce loads, or even by an equal percentage reduction in all loads, as BGE apparently assumed for the SEM. The need for particular transmission projects may be driven by winter load and generation patterns, by the need to export power from the BGE zone, by concerns about system stability at low loads, or other factors that would not be affected by the load-management programs or even the hypothetical SEM reductions.

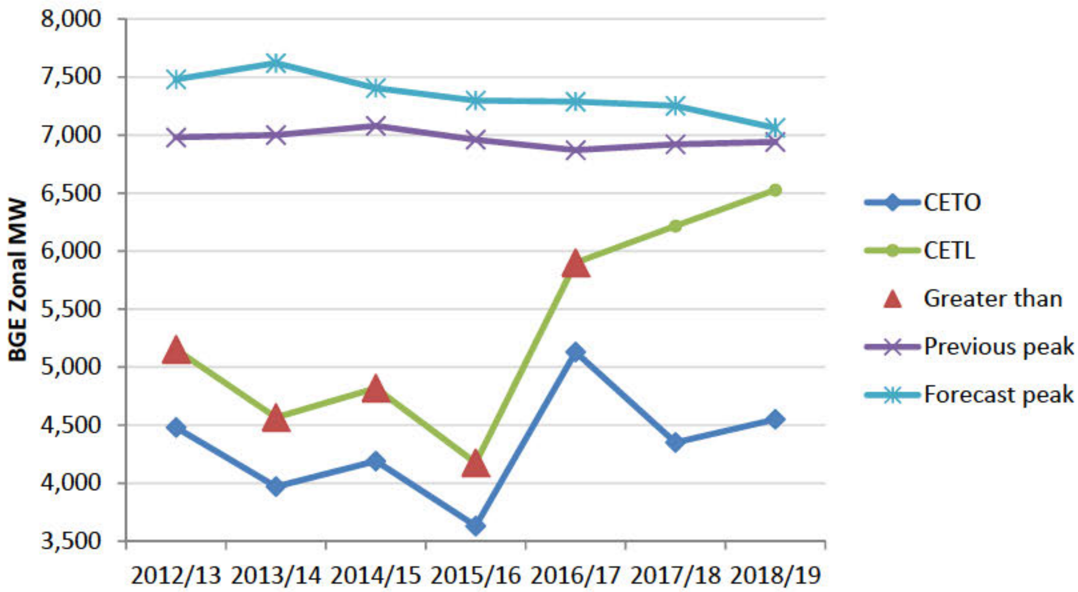
Seventh, while BGE assumes that one megawatt of load reduction (at BGE's peak for SEM and at various hours for SER and PR) would reduce the required import capability by one megawatt, BGE has no idea how PJM determines the required import capability (OPC DR 4-39, which simply refers to the PJM web site for the Regional Transmission Expansion Planning (RTEP) process, which links to dozens of documents).

Eighth, BGE's import capability estimate of 6,527 MW is not taken from the RTEP, but from the Capacity Emergency Transmission Limit (CETL) reported in the 2018/19 BRA planning parameters.[34] The same document lists the 2018/19 BGE import requirement (Capacity Emergency Transfer Objective, or CETO) as 4,550 MW, to support a forecast zonal peak load of 7,062 MW. As far back as the 2012/13 BRA, PJM listed BGE's import limit as ">5,152" MW, which is greater than BGE's current import requirement, and a requirement of 4,480 MW, to support a forecast peak of 7,480 MW. It does not appear that any transmission additions have been required to increase import capability from 2012 to 2018, since the 2012 capacity exceeds the 2018 requirement.

Figure 7 shows that the import capacity (CETL) has increased even as import requirement (CETO) bounced around, actual peak decreases slightly, and forecast peak decreases more decisively. Note that in the first four years, PJM did not provide an estimate of the exact CETL, but only that it was more than 15% higher than CETO. It appears that factors other than load have driven the CETL. BGE's assumption that the CETL varies directly with peak load is not supported by the evidence.

[34] While BGE buries the origin of its import-capability value behind a vague reference to the RTEP process, Exeter reports that BGE "estimated the load carrying capability of transmission at the Capacity Emergency Transfer Limit (CETL)" (Exeter report at 31).

Figure 7: PJM Forecasts of BGE Load and Transmission Requirements



Q: What would be the effect of dividing the escalated transmission cost by BGE's forecast peak, rather than the 2018/19 CETL?

A: This improvement in the methodology 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.

B. Distribution

Q: Do you have any additional information regarding the effect of reductions in peak substation loads due to the load reductions from the SER and PR programs?

A: Yes. I have identified three lines of evidence.

First, for the purposes of the COSS, BGE assumes that distribution investments are driven by class peak loads; the test-year residential class peak occurred in the winter (OPC DR 3-06), when the SER and PR would have no effect.

Second, the substation-specific data (OPC DR 4-52, Attachment 3) indicate that, of some 400 BGE distribution substations, 123 experienced their 2013 peak loads during the SER hours, 10 in the 2014 SER hours, and 33 in the 2015 SER hours. Only 18 of the substations that peaked in the 2103 SER hours also peaked in the 2015 SER hours.[35] In order to avoid distribution additions, the SER program would need to reliably reduce peak loads year after year; in the first three years of the SER program, BGE managed to consistently call Energy Savings Days on the peaks for less than 5% of substations. It is difficult to believe that BGE distribution planners would depend on such an unreliable program to reduce load on the substation peaks.

Worse yet, the 2013 data show some 52 substations peaking on the Energy Savings Days after 7 PM, when the rebound from the SER program would have increased load.[36] The SER may actually increase peak loads on some substations in some years.

Third, BGE acknowledges that some residential-dominated substations peak in the summer, and others in the winter, when the SER and PR programs have no effect.

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[35]In addition to peaking before and after the ESDs, substations peaks are spread over many more days than the handful of ESDs that BGE can call in any summer.

[36] I deal with rebound in Section V.B. Mr. Chang also discusses rebound in his testimony.

> For example, a substation load center might have a large concentration of residential air-conditioning end-use customers. As a result, distribution substations and feeders in this load center are typically going to be sized according to the late afternoon or early evening high demand summer peaks when air-conditioning use is most prevalent for residential customers. Alternatively, certain distribution substations and feeders may have a large concentration of electric resistance heating end-use customers that drive a winter peak. As a result, distribution substation and feeders in this load center are typically going to be sized according to the high demand winter peaks when electric heating use is prevalent. (Greenburg Direct at 18)

BGE also acknowledges that some substations, even though they serve some residential load, hit their peak loads due to the demands of other classes:

> Other substation load centers may be dominated by Schedule P peak loads that are mixed with industrial processing and cooling profiles. These peak loads will be less weather sensitive and more of a function of economic activity when compared to residential peaks. Substations and feeders serving Schedule P loads are going to be sized to accommodate cyclical production requirements as opposed to serving seasonal weather sensitive peaks. In another example, where a load center may have a cluster of street lighting, the distribution substations and feeders are going to be sized in a minimal manner to meet these customers' off-peak night time load requirements. (Greenburg Direct at 18)

Q: Please summarize your conclusions regarding the avoided transmission and distribution investments from BGE's demand-response programs.

A: It is unlikely that there have been or will be any such benefits.

V. Claimed Energy Benefits

Q: What categories of energy benefits does BGE claim in its cost-benefit analysis for the smart meters?

A: BGE includes past and future energy revenues from energy sold to the PJM market, avoided energy costs, and energy price mitigation.

I assume that BGE has accurately reported the energy revenues that BGE has already received. Otherwise, I have identified problems in all these categories of claimed energy benefits.

A. Energy Revenue

Q: What are the most important factors in BGE's estimates of energy revenues?

A: BGE's estimates of the future energy payments it would receive from the PJM SER and PR programs depend on the following parameters (in addition to the load reductions):

- 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.

Q: What problems have you identified in these assumptions?

A: I found two problems. First, BGE extrapolates the emergency price from a 2014 price **BEGIN CONFIDENTIAL** ($[redacted]/MWh) **END CONFIDENTIAL** for emergency energy in the extreme winter conditions, including spiking gas prices. The actual price in the last summer emergency event, 9/11/13, was $1,181/MWh.

Second, BGE assumes that two of the four ESDs for the SER each year will be called on days that turn out to be emergency events, even though just one summer emergency event has occurred in the last three years (September 11, 2013, OPC DR 4-04) and there is no assurance that BGE will know a day in advance that an emergency will be called by PJM.

Indeed, from the PJM Emergency Procedures web site, it appears that PJM issued only four calls for summer emergency load management in 2007 through 2012, for a total of five such calls in nine years.[37] Assuming an average of even one emergency event annually would be generous.[38] Considering that emergencies can occur on days that BGE has not called as ESDs the day before, a 50% annual chance of an emergency on an ESD seems more appropriate than BGE's estimate of 2 such events.[39]

Q: What is BGE's basis for its estimate of the number of emergency days?

A: BGE says that "The number (two) and duration (3 hours) of PJM emergency events is based on Mr. Pino's experience in PJM markets" (OPC DR 17-6).

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[37] In OPC DR 16-2, BGE lists one summer emergency event each in 2011 and 2012. I found one more in 2008 and two in 2007.

[38] BGE carries that error over to the PR Enhancements. While the PR savings can be dispatched in response to a developing emergency, there are still very few emergencies during which the air-conditioning portion of the PR program could provide energy.

[39] BGE has often called an ESD when PJM issues a Maximum Generation Emergency/Load Management Alert. That would explain the timing of the ESDs on 7/17, 7/18 and 9/11 in 2013, but BGE did not call an ESD for 7/16/2013 (for which PJM had issued a Max Generation alert) and did call an ESD for 7/10/2013 (even though PJM issued no warning on the previous day). In 2015, BGE called ESDs for 6/23, 7/21 and 7/29, following hot weather alerts, but did not similarly respond to hot weather alerts for sixteen other days in May, June, July, August and September. In 2014, there were eight hot-weather alerts, but BGE did not call ESDs for any of those days.

Q: What are the effects of correcting these two problems?

A: Correcting the number of emergency ESDs from 2 to 0.5 annually reduces the SER and PR revenues by about $13 million, while reducing the summer emergency price to the last actual value reduces revenues another $1 million.

B. Avoided Energy Costs

Q: What problems have you found in BGE's analysis of avoided energy costs?

A: I have identified three significant problems with BGE's analysis:

- Assuming that the avoided energy cost is equal to the standard-offer rate.
- Ignoring load shifting in the SER and PR programs.
- 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.
- BGE failed to include the cost of purchasing load reductions thought the Peak Time Rebates. As discussed further in Mr. Chang's testimony, the SER rebates are not just transfers, but payments to get customers to accept significant inconvenience and discomfort.

Q: What was wrong with assuming that the avoided energy cost is equal to the standard-offer rate?

A: The standard-offer rate covers energy, renewable credits, capacity, losses and various ancillary services and PJM charges. Reducing energy use reduces most of the significant categories of costs in the standard-offer rate, but not the capacity portion or the associated losses. If the programs reduce energy without reducing capacity obligation, suppliers (both for standard offer and for retail service) will raise their energy charges to cover the higher costs.[40] In addition, BGE accounts for the avoided capacity costs separately (as I discuss in Section III.B), so also including capacity in the avoided energy cost would double-count the benefit.

Q: What would be a more reasonable approach to estimating the avoided energy cost?

A: The avoided energy cost should represent only the energy portion of the standard-offer price. I estimated the non-capacity portion of the standard-offer price by year. In periods for which BGE has not yet fully procured standard-offer supply, I averaged in the forward prices for those periods as of January 15, 2016, times the historical ratio of non-capacity standard-offer price to contemporaneous forwards.

Q: How did you compute the effect of correcting BGE's error of including capacity prices in avoided energy-related costs?

A: I looked back at the prices of standard-offer (SO) supply that BGE has procured for January 2013 through May 2018. I subtracted an estimate of the capacity-related portion of the monthly SO price costs from each procurement, and computed the ratio of energy-related SO price to the simple average of on-peak and off-peak forwards for the same month. Like BGE, I filled in the remainder of the standard offers for which BGE has procured only a portion of the requirement; while BGE stopped this computation in 2017, I included the actual procurements through May 2018. Both for the partially-filled standard-offer periods and through 2020, I estimated the

[40] If a supplier were caught unaware by such a change in load, the ratepayers might receive a windfall in the year or so before prices can be reset. BGE has not constructed a case for believing that suppliers are unaware of BGE's programs.

energy-related costs of future procurements as the product of forward prices times the average ratio of SO energy price to forwards. After the end of current futures in 2020, I adopt BGE's escalation rate for avoided energy costs.

Q: How much does this correction reduce BGE's estimate of avoided energy costs?

A: This one correction reduces the avoided energy costs by 30%, or about $40 million.

Q: How much of the energy avoided costs would be offset by load-shifting to hours outside the incentive period for SER?

A: The Brattle Impact Table tab in the Market Benefits workbook (Staff DR 6-02 Confidential Attachment 15) shows additional energy usage in the two hours before and one hour after a five-hour incentive period of an ESD, totaling **BEGIN CONFIDENTIAL** [redacted]% to [redacted]% **END CONFIDENTIAL** of the reduction during the incentive period.[41] Energy use may well rise even earlier (as households move up the time of laundry loads, cooking, and dishwashing, and precool their homes in the morning) and continue to be elevated later in the evening (as residents catch up with delayed activities). It seems reasonable to assume that at least 40% of the energy in the incentive period is recovered earlier and later. This correction would reduce the present value of the avoided energy costs by over $2 million and the energy price

[41] The Market Benefits workbook and the reports in the OPCDR 24-03 Attachments do not provide comparable data for a six-hour incentive period or for more than two hours before and one hour after the incentive period.

mitigation by $1 million.[42] The SER program provides only a small part of BGE's projected energy savings and energy price mitigation, which are dominated by SEM.

Q: Does BGE acknowledge that load shifting will increase energy use in hours outside the incentive period?

A: Yes, BGE admits such load shifting occurs. "BGE expects there to be some accommodation by customers in response to an energy savings day" by increasing usage in the hours before and after the SER hours (OPC DR 16-15). Navigant, in the evaluations of the SEM program, says that "SER encourages customers to reduce their usage during peak hours, which might be offset by increased usage during non-peak hours" and suggests that all the SER's incentive-period savings may be offset by increased load in other hours: "Navigant expects double counted savings to be small or non-existent, because SER encourages customers to reduce their usage during peak hours, which might be offset by increased usage during non-peak hours." (Staff DR 8-24 Attachment 1 at 12, Attachment 2 at 20).

Having acknowledged the increased energy use, however, BGE failed to add energy costs to offset part of the claimed savings.

Q: Does BGE provide any analysis to support its decision to ignore the increased energy use from load shifting?

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[42] A similar shifting effect may occur for the PR program, if participants set their thermostats lower on hot days (anticipating the possibility of a cycling event) or even all summer. BGE apparently ramps down the cycling in the last hour of the control period, to avoid a sharp spike at the end of the control period. That strategy may significantly reduce the rebound in the first hour following the control period. I have not analyzed the PR load shifting further, given the small amount of benefit attributed from that program attributed to the smart meters.

A: No. BGE has not prepared any analysis of either "the increase in consumption for hours on Energy Savings Days other than hours ending 14 through 19," nor "the increase in consumption for summer days other than Energy Savings Days." (OPC DR 24-05) In the absence of any information, BGE claims that "Such accommodation, however, would be captured in the SEM program results." (ibid.)

Q: Is BGE's response valid?

A: No. If the SEM program results captured the increased loads outside the incentive period, they would also capture the decreased load within the incentive period. By BGE's logic, it has chosen to double count the same load reductions in both the SEM and SER, but ignore the load increases from the SER.

Q: How else did BGE overestimate the load reductions due to the SER?

A: As I explained in Section III.B.1, BGE's definition of SER savings treats random reductions in usage as SER benefits, but ignores the offsetting increases in usage. Put another way, BGE fails to correct for free riders.

Q: Can you estimate the extent to which omission of the non-participants biases BGE's analysis of energy savings?

A: The corrections method that I describe in Section III.B.1 would reduce BGE's estimate of the SER energy savings by about the same percentage as the demand reductions (a bit over 30% in most years), reducing the present value of energy revenues by $6 million, avoided energy cost by $2 million, and demand-side price mitigation by $2 million.

Q: How does BGE treat the SER rebates of $1.25/kWh for SER participants?

A: BGE ignores these payments. "BGE did not include the SER bill credits in the evaluation of the Smart Grid cost-effectiveness." (OPC DR 24-01)

Q: What is BGE's rationale for excluding these payments?

A: BGE says that these payments are not costs. "The bill credits are an intra-customer transfer and do not affect the cost-effectiveness. All customers pay for the cost of the SER bill credits, while the SER participants receive the benefit of the bill credits. Overall, this is a net zero cost for the customer base." (OPC DR 24-01)

Q: Is this a reasonable position?

A: No. The SER asks customers to suffer discomfort and inconvenience, to tolerate higher indoor temperature and humidity on the most unpleasant summer days, and to rearrange their household schedules. A household that bears some discomfort to save a kilowatt-hour, because the $1.25 is just enough worth enough to motivate increasing the thermostat setting, just about breaks even on that ESD. But the other customers pay the $1.25, which offsets whatever other benefits they may get from the smart meters.

BGE recognizes that the corresponding bill credits for the PR programs are costs, and counts termination of bill credits as a benefit.

Q: How is this situation different from rebates for energy-efficiency investments?

A: The cost side of the Total Resource Cost (TRC) test for energy efficiency includes the costs of the measures, including payments to installers to compensate them for the installations and to trade allies to induce them to change their behavior. This is true even if the installers and trade allies are

BGE customers.[43] Rebates paid to customers generally offset part of the measure costs that the customers would otherwise bear; since those rebates are part of the estimated costs of the measures, they are not added again to the TRC costs.

In the case of the SER, the person doing the work, incurring inconvenience and discomfort, and changing behavior are the customers.[44] Just like the trade allies and installers of energy-efficiency measures, they will not take on those burdens without being paid. That is why BGE is willing to pay them $1.25/kWh for reductions in usage on the ESDs. BGE is paying for the customers' efforts and achievements. Ignoring those payments ignores the costs the participants are bearing.

Q: Should the entire $1.25/kWh payment be treated as a cost?

A: There are two ways to address that question. First, it is normal practice to count the full payment for services as a cost, even if the service provider is also a customer of the utility. Examples include payments to utility customers who are utility employees, EmPOWER installers and trade allies (as I mentioned above), or (formerly) generation owners selling power to the utility. From this perspective, the full $1.25/kWh would be treated as a cost.

The second view tries to differentiate between the payments that SER participants receive and the cost to those customers of earning the rebate. As I explain above, some customers are free riders, who do receive a Peak Time Rebate without making any special effort to do so; for them, the rebate is

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[43] The same is true for BGE's payments for supply-side services, such as for its T&D employees and contractors.

[44] In the case of the PR program, the customer incurs discomfort and may experience some of the other costs, as well.

entirely a windfall transfer from other customers. Some active participants might have taken some of the actions necessary to reduce usage in the incentive period for a 5¢/kWh premium or less, so most of their bill credits are windfalls. Other customers might not take the necessary actions unless they received the full $1.25/kWh incentive, since that is barely enough to overcome their aversion to discomfort or inconvenience.[45] From this perspective, the cost to the average participant would be somewhere between $0/kWh and $1.25/kWh, perhaps half the payment, or $0.625/kWh, with the rest being a transfer.

Even half of the incentive payment would have a present value of $48 million.

C. Energy Price Mitigation

Q: How does BGE estimate the energy price mitigation resulting from reductions in energy consumption?

A: BGE starts by using hourly regressions of zonal energy prices as a function of BGE load to estimate the percentage change in prices in each Maryland zone for each 1% of BGE load conserved.[46] BGE then multiplies the following three factors for each Maryland zone in each year:

- BGE's estimate of the zonal energy price.
- The PJM forecast of annual Maryland zonal load.
- The coefficient from its zonal regression.

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[45] The same phenomenon must apply to some BGE employees and contractors, as well, but standard practice treats all those payments as costs, even though some of the payment is a windfall to people who are also BGE customers.

[46] BGE actually conducts the analysis separately for peak and off-peak energy.

The result of that computation is an estimate of the millions of dollars in price benefits to Maryland customers per percent change in BGE load. Finally, BGE multiplies the sum of the benefits (per percentage-point change in BGE load) times its estimate of the total program energy savings as a percentage of BGE load, to derive an estimate of the total price benefits to Maryland from the BGE programs.

Q: What problems have you identified in BGE's analysis of energy price mitigation?

A: BGE's estimate reflects errors I discuss above: using an overstated energy forecast, ignoring load shifting (Section V.B above) and random variation in usage. Most importantly, BGE errs in assuming that the BGE zone is the only load that affects prices in the BGE, PEPCo, Delmarva, and AP zones.

Q: Please explain how BGE determined the effect of BGE load on price in each zone.

A: As shown in OPC DR 4-65, BGE performed three to five regressions for each zone and period (on- or off-peak), using hourly day-ahead prices and loads from January 2013 through February 2015, normalized to the monthly average.[47] In each regression, BGE used a single independent (or driver) variable, which was either the normalized hourly load in one zone or the normalized total load in two to four zones. Mr. Pino claims that the analysis "estimated the percent change in price (day-ahead LMP) in PJM zones that contain Maryland electric customers (BGE, Pepco, Delmarva, and Potomac Edison) due to a 1% change in demand in the BGE zone." (Pino Direct at 50)

[47] This normalization process removes the price variability between months due to such factors as fuel prices and maintenance schedules. I have used this approach in my analyses of energy price mitigation for New England and Illinois.

Table 7 summarizes BGE's results, which show that the on-peak prices in the various zones change by 2%–3% when BGE load changes 1%, while off-peak prices change 1.4% to 2%. For BGE, PEPCo and Delmarva, the percentage change in price generally rises as the load area is broadened from one utility to two to three to four. For AP, the highest price coefficient occurs with the AP-only regression.

Table 7: BGE Regression Results,
% change in zonal price per % change in load in indicated zones

	Load zone(s)						
Price Zone	**BGE**	**PEPCo**	**DPL**	**AP**	**BGE+ Pepco**	**BGE + Pepco + DPL**	**BGE + Pepco + DPL + AP**
On-peak							
BGE	*2.51*	2.52			2.64	2.61	**2.92**
PEPCo	*2.52*	2.68			2.65	2.62	**2.93**
DPL	*2.42*		2.31			2.51	**2.82**
AP	*2.08*			**2.83**			2.45
Off-peak							
BGE	*1.75*	1.73			1.82	1.81	**2.01**
PEPCo	*1.73*	1.86			1.80	1.79	**1.99**
DPL	*1.67*		1.64			1.73	**1.93**
AP	*1.38*			**1.82**			1.60

Notes: ***Lowest R^2***, **highest R^2** in row.

Q: Do the results of these regressions imply very similar price effects for a 1% reduction in BGE load?

A: No. The results in Table 7 show the percentage price change in a zone *when* there is a percent load change in one or more zone. In the BGE column, the regression uses only BGE load, but the next three columns do not use BGE data at all, and BGE is only a quarter of the total load in the four zones, as used in the right-hand column. Table 8 converts the results in Table 7 to the percent change in BGE load. Depending on which regression BGE selected, it would have found that when BGE's load changes 1%, PEPCo's on-peak price (as example) could change 2.52%, 0%, 1.36%, 1.04% or 0.72%.

Table 8: BGE Regression Results,
% change in zonal price per % change in load in BGE zone

Price Zone	BGE	PEPCo	DPL	AP	BGE + Pepco	BGE + Pepco + DPL	BGE + Pepco + DPL + AP
	Load zones(s)						
BGE as % of regression load							
	100%	0%	0%	0%	51%	40%	25%
% change in price per % change in BGE load							
On-peak							
BGE	*2.51*	–			1.35	1.03	**0.72**
PEPCo	*2.52*	–			1.36	1.04	**0.72**
DPL	*2.42*		–			0.99	**0.70**
AP	*2.08*			–			0.61
Off–peak							
BGE	*1.75*	–			0.93	0.72	**0.50**
PEPCo	*1.73*	–			0.92	0.71	**0.49**
DPL	*1.67*		–			0.69	**0.48**
AP	*1.38*			–			0.39

Q: Do the BGE regressions indicate how much a change in BGE load changes energy prices in the various zones?

A: No. As I noted above, these regressions cannot tell us how much price changes *as a result of* load changes in one or more zones, but only how much price changes *when* load changes. When load increases in the BGE zone, it will usually increase in other zones (including areas that BGE did not model, such as New Jersey, western MAAC, and non-AP portions of western PJM); collinearity of the load data prevents the regressions from definitively determining which loads drive the prices. The correlation among the zonal loads means that the regression coefficient for load in one zone may actually represent the effects of load in other zones, whether those are included in the regression or not. In these situations, I have found that regression coefficients may be negative (implying incorrectly that increasing load decreases price) and the coefficient for local load may be lower than the coefficient of more remote load (which also makes no sense). Nonetheless, a combination of statistical results and fundamental considerations regarding the cost drivers can guide the selection of reasonable results.

Q: Is there a statistical basis for choosing among BGE's regressions?

A: If these were the only available analyses, one might look to the statistical power of the various regressions. Whether measured by R^2, adjusted R^2, or the F statistic, the regressions using only BGE load (the first column in Table 7 and Table 8) consistently perform worst. For predicting the BGE, PEPCo and Delmarva prices, the best-performing regression uses the sum of all four zones. For Potomac Edison price, the best-performing regression uses only AP load; BGE's load does not improve the fit of the equation.

Q: What was BGE's basis for choosing the worst-fitting equation for each zone?

A: BGE has not provided any rationale for this poor choice from its own results.

Q: Is there a logical reason to select the equations that BGE selected?

A: No. It is preposterous to suggest that a change in load in the BGE zone has a larger effect on prices in the PEPCo zone than a change in PEPCo load, a larger effect on prices in the Delmarva zone than a change in Delmarva or PEPCo load, or a larger effect on prices in the AP zone than a change in the PEPCo load or especially a change in AP load. Give how closely connected BGE and PEPCo are, it is difficult to believe that PEPCo load would not affect BGE load and vice versa. Since most transmission connections between Delmarva and BGE run through the utilities of EMAAC (especially PECo) and WMAAC (especially PPL and MetEd), it is likely that load in

EMAAC and WMAAC is at least as important in determining Delmarva prices as is BGE load, and vice versa. And given the connections of AP to Dominion, AEP and WMAAC, it is difficult to believe that those areas do not affect AP prices.

Q: Which of the BGE regression runs are most reasonable?

A: Of this set of analyses, the most reasonable specifications appear to be the regressions that use the sum of the four zonal loads for BGE, PEPCo and Delmarva, and the AP-only regression for AP. Those results are probably still biased in the following ways:

- Overstating the influence of BGE load on the BGE, PEPCo and Delmarva prices, since correlated load changes in other parts of PJM (western MAAC, the non-Delmarva portion of EMAAC, and portions of western PJM, such as Ohio) probably contribute to the changes in prices.
- Understating the influence of BGE load on AP prices, which may be small but are unlikely to be zero.

These values do not tell us anything about the price change due to any particular load change. When loads are high in the BGE, PEPCo, Delmarva and AP zones, loads are also likely to be high in western MAAC, EMAAC, Dominion, ATSI and AEP. Loads in the ComEd zone, eastern MISO, and New York may also move generally with the loads in the MD zones, although ComEd is in the Central time zone (shifting schedules one hour later) and transmission is more constrained from most of these areas (except for western MAAC, which lies between BGE and AP) than transmission among the Maryland zones.

Q: Have you conducted any additional analysis of the effects of BGE load on energy prices in the four Maryland zones?

A: Yes. I have run a number of other regressions, using various combinations of PJM, MAAC, WMAAC, and local zones. The best fits I found, which are summarized in Table 9, are more realistic than BGE's preferred runs (since they reflect loads other than BGE's), or even the best runs that BGE performed (since they recognize the effect of wider areas). The statistical tests for the equations in Table 9 are generally better than those for BGE's regressions.[48]

Table 9: Improved Regressions for Maryland Load Zones
% change in zonal price per % change in load

	Load zone(s)						
Price Zone	**BGE + Pepco + DPL**	**AP**	**WMAAC + AP**	**PJM – ComEd**	**R^2**	**BGE % of Variable**	**% price Δ per BGE % price Δ**
On-peak							
BGE	1.46	1.58			0.48	40%	0.58
PEPCo	1.46	1.60			0.48	40%	0.58
DPL	1.10		2.10		0.51	40%	0.44
AP				2.81	0.42	5%	0.14
Off-peak							
BGE	1.08	1.00			0.48	40%	0.40
PEPCo	1.11	0.96			0.48	40%	0.39
DPL	1.37		0.53		0.48	40%	0.55
AP				1.67	0.40	5%	0.08

Q: What are the implications of these results for BGE's estimates of energy price mitigation?

48 Using the off-peak AP-only equation that BGE developed for AP would increase the R^2, but eliminate the effect of BGE's load on AP price. I tried to use the EMAAC load as a driver for the Delmarva regression, but the sign on the APC+WMAAC variable became negative.

A: This improvement would reduce the energy price mitigation by 79%, or $80 million (about $4 million reduction in SER benefits, $76 million reduction in SEM benefits).

VI. Summary of Corrections

Q: Please list the errors you have found in BGE's analysis of system benefits from the load reductions that BGE attributes to smart-meter-enabled programs.

A: In Sections III through V, I identified the following errors:

- Avoided Capacity Cost
  - The load forecast from which BGE estimates the SEM savings is outdated.
  - The capacity obligation for BGE customers will not be significantly reduced by the SER and PR load reductions, because they affect very few of the thousands of summer days used in the PJM peak forecasts, and the affected days are not well chosen to change PJM's load forecasts.
  - BGE overstates the SER load reductions, by ignoring customers whose load increased on ESDs and hence not offsetting reductions that would have occurred without the program with increases that occurred even with the program.
  - The load reductions from SEM would tend to affect capacity obligation much more slowly than BGE assumes, with only about 30% of the 2013–2015 reductions affecting the 2016 forecasts that will determine BGE's 2019/20 obligations.

- Capacity Price Mitigation
  - The load forecasts from which BGE estimates the energy affected by price mitigation are outdated.
  - While capacity bid into the RPM from the SER and PR programs has and will tend to reduce capacity prices through 2020/21, it will also increase capacity obligations.
  - Load reductions not bid into the RPM have negligible (for the SER and PR) effects on market price, due to their rarity and timing.
  - BGE overstates the SER load reductions, by ignoring load increases.
  - The load reductions from SEM would reduce capacity prices much less than BGE assumes.
  - BGE's estimate of the effect of load reductions on capacity prices is grossly overstated.
  - Historical experience suggests that capacity prices in the Delmarva service territory will often be unaffected by supply and demand in the BGE zone.
  - BGE incorrectly assumes that its demand response resources always reduces prices for premium resources.
- Transmission and Distribution Benefits
  - BGE computes its avoided T&D values from the average escalated cost of all plant in specific categories, not the marginal or avoidable costs.
  - BGE failed to annualize the deferral of T&D costs, and treats the hypothetical deferral of costs as if the costs were permanently eliminated.

    - BGE has not demonstrated that it actually deferred any projects due to the SER, PR or SEM load reductions, or even that it takes those reductions into account in T&D planning.
    - The SER and PR load reductions, given their rarity and timing, are unlikely to affect transmission or distribution investment, given the variability in the timing of peaks on T&D equipment.
    - The peak loads on the transmission lines have not fallen on the ESDs, most have not fallen in the SER incentive hours, and winter peak line loads have often been higher than summer loads.
    - The driver of transmission costs identified by BGE (import capacity) does not seem to be little well-correlated with BGE's peak loads, and it is not clear that any projects driven by import requirements have been planned for installation since 2013 or will be avoidable in the future.
    - The distribution substations usually peak at hours other than the ESD incentive hours, including after the incentive hours when the SER increases load.
- Energy Revenue
    - BGE apparently overstates the price of summer emergency energy.
    - BGE overstates the frequency of summer emergency events.
- Energy Savings
    - BGE ignores load shifting in the SER and PR programs.
    - BGE overstates the SER benefits, by including randomly-occurring load reductions while excluding randomly-occurring increases on the ESDs.
    - BGE overstates the avoided energy cost by including the capacity-related portion of the standard offer as part of the energy benefit.

Energy savings do not reduce the capacity costs allocated to the BGE zone or to MD, and BGE's analysis deals separately with the capacity avoided cost and price mitigation.

  - BGE failed to reflect the cost of buying energy savings through the Peak Time Rebates.

- Energy Price Mitigation
  - BGE uses outdated and exaggerated forecasts of sales.
  - BGE incorrectly assumed that energy prices for each of the Maryland zones is driven solely by BGE's load.
  - BGE overstates SER savings (and hence the effect on prices) by ignoring rebound and by including the random reductions and excluding the random increases on ESDs.

Q: Please summarize the system benefits with your adjustments.

A: Table 10 updates Table 1 to reflect the adjustments I made above.[49]

[49] I generally modified the small incremental PR savings in proportion to the changes in the SER savings.

Table 10: Adjusted System Benefits, $M of 2015 PV

Generation Capacity	SER	SEM	PR	Total
Capacity Revenue	$42	–	$1	$43
Avoided Capacity Cost	$1	$9	–	$9
Capacity Price Mitigation				
Supply Side	$23	–	$0	$23
Demand Side	$0	$2	–	$2
Transmission and Distribution				
Transmission	–	$8	–	$8
Distribution	–	$6	–	$6
Energy Revenue				
LMP	$2	–	$0	$2
Emergency	$3	–	$0	$3
Avoided Energy Cost	$2	$92	$0	$95
Energy Price Mitigation	$0	$17	$0	$17
Avoided Emissions Cost	$0	$4		$4
Total	$74	$134	$2	$210

For the purposes of this summary, I have accepted BGE's assumptions about the percentage reduction in energy and peak loads attributable to the effect of the smart meters on the SEM program. If these savings are not realistic or could have been achieved without the smart meters, the SEM column should be reduced or eliminated. Mr. Chang adjusts the SEM savings in his testimony and also reflects the SER rebates, which are logically treated as a program cost.[50]

Q: Does this conclude your direct testimony?

A: Yes.

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[50] I have not undertaken the substantial effort required to re-estimate BGE's avoided transmission and distribution costs per kilowatt of peak load reduction on the facilities. After correcting for other BGE errors that affect the T&D benefits (most importantly, the SER and PR programs do not reduce of transmission and distribution peaks), the residual T&D benefits from the SEM do not warrant that effort.