ORDER NO. 83571

IN THE MATTER OF POTOMAC ELECTRIC POWER COMPANY AND DELMARVA POWER & LIGHT COMPANY REQUEST FOR THE DEPLOYMENT OF ADVANCED METER INFRASTRUCTURE	* * * * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9207

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I. Introduction and Executive Summary

In this Order, we approve in principle the joint proposal of the Potomac Electric Power Company ("Pepco") and Delmarva Power and Light Company ("Delmarva") (collectively, "PHI" or "the Companies") to: (1) deploy advanced metering infrastructure ("AMI") in Maryland; (2) establish regulatory assets to defer recognition of associated incremental costs; and (3) develop and submit to the Commission certain dynamic pricing tariffs (the "Proposal"), subject to the modifications and parameters set forth herein. With respect to Pepco, this Order amplifies, and regarding legacy meter cost recovery, modifies, the direction we provided on August 13, 2010, in Order No. 83532.

In issuing this Order, we recognize the potential of AMI to deliver substantial benefits to the Companies' customers. PHI expects that AMI will enhance its outage detection and notification capabilities by remotely verifying when a meter is in or out of service,[1] for example, and that it will help improve service restoration times.[2] The Companies also project that AMI deployment throughout their Maryland service

[1] Direct Testimony of PHI witness George W. Potts ("Potts Direct") at 29, 32 (Exh. GWP-1).
[2] Tr. 26-27 (PHI witness William M. Gausman).

territories will yield operational and maintenance ("O&M") cost savings by eliminating the need for manual meter readings, enabling remote service connections and disconnections, improving billing activities, and enhancing customer complaint management, among other things,[3] and those savings will be passed on to the Companies' customers.

The Proposal's cost-effectiveness depends in part, however, upon other factors over which the Companies have far less control. The majority of AMI-enabled cost savings projected by the Companies arise from PHI's predictions about the degree to which the dynamic pricing options they propose will motivate customers to reduce electricity usage during Company-declared critical peak demand periods, and about the impact of that reduction on wholesale market prices.[4] But the foundation for the Companies' predictions about these "supply-side benefits" is far from certain, in our view. PHI's projections about its customers' response to dynamic pricing options are based upon a "Pricing Impact Simulation Model," calibrated to the results of a pilot program conducted by Baltimore Gas and Electric Company ("BGE") in the Summer of 2008.[5] The Companies have performed no dynamic pricing pilots of their own in Maryland, nor have they developed the type of comprehensive customer education and communications program that the parties to this Case agree will be necessary to achieve the customer participation levels PHI projects. And they have not yet determined the manner in which they will monetize projected supply-side savings for the benefit of their customers. Similarly, the record provides scant evidence supporting the Companies'

[3] Potts Direct at 6.
[4] *See, e.g.*, Potts Direct at 13.
[5] Direct Testimony of PHI witness Dr. Ahmad Faruqui ("Faruqui Direct") at 9-10.

prediction that access to the more granular measurements of electricity consumption enabled by so-called "smart" meters will cause customers to reduce their electricity consumption by 1.5%.

The Companies' cost-benefit analyses also do not include certain costs that are critical to the success of the Proposal, or that necessarily will be incurred down the road if customers are to realize the full potential of smart meters and a smart grid. For instance, in our view, the Companies did not include in their cost-benefit analyses a sufficient budget for customer education and communications. The current Proposal also does not include the costs associated with in-home displays that would provide customers with real-time price signals, or smart appliances that ultimately will be capable of communicating with the new smart meters, thereby enhancing customers' ability to effectively manage their energy use.

These limitations in the Companies' business cases, as well as the technological risks associated with AMI adoption at this stage of its evolution, raise concerns about whether the Companies' proposed investment in AMI ultimately will prove cost-effective. In the case of Pepco, these concerns are mitigated, in part, by the United States Department of Energy's ("DOE") award to Pepco of a $104.8 million Smart Grid Investment Grant, $68.3 million of which will be used to partially offset the cost of AMI deployment.[6] Technological risks for both Companies also are mitigated by the contractual protections PHI has incorporated in its AMI vendor contracts, and by the Companies' intention to apply any lessons learned from Delmarva's AMI deployment

[6] The balance of the grant will be allocated as follows: (1) approximately $25.5 million to Pepco's current Direct Load Control program; (2) approximately $7.5 million to Pepco's Distribution Automation project, designed to reduce the number and duration of electric system outages; and (3) approximately $2.7 million to an expanded communications infrastructure project. Tr. 104-05 (Gausman).

currently underway in Delaware to the Companies' AMI deployment in their Maryland service territories.[7] On the other hand, because Delmarva was not awarded a federal grant, the potential of not realizing a level of cost-effectiveness projected for that Company's AMI project in Maryland is substantially greater than it is for Pepco. Accordingly, before we will authorize Delmarva to commence AMI deployment in its Maryland service territory (which the Company has testified it does not intend to do until approximately mid-2011 in any event),[8] we require that Delmarva submit for the Commission's consideration an amended business case consistent with the terms of this Order, as set forth more fully below.

In accordance with the parameters set forth in Order No. 83532, we direct Pepco to submit a similarly amended business case, but for Pepco, we do not condition our authorization to commence AMI deployment upon our assessment of that submission. We further direct both Companies to submit to the Commission a plan detailing how they intend to fund their proposed Critical Peak Rebate dynamic pricing structure, including the manner in which they intend to monetize peak demand and energy use reductions attributable to AMI. We also will require the Companies to develop – in consultation with the other parties to this Case – and to submit for Commission approval: (1) a detailed and comprehensive customer education and communications plan, which shall comply with the specifications provided in this Order, and which we expect the Companies to launch sufficiently in advance of AMI deployment in Maryland to optimize customer awareness and engagement; (2) a corresponding customer education and

[7] Direct Testimony of PHI witness William M. Gausman ("Gausman Direct") at 8.
[8] Reply Testimony of PHI witness William M. Gausman ("Gausman Reply") at 5.

communications budget; and (3) a comprehensive set of metrics for all aspects of the Proposal, including but not limited to: (a) installation and performance of the technology; (b) incremental costs incurred; (c) incremental benefits realized; (d) effectiveness of customer education and communications efforts, to include, among other things, customer satisfaction and participation levels; and (e) customer privacy and cybersecurity. We will require the Companies to report to us their respective performance against these metrics, and to appear for periodic review hearings in which we will monitor each Company's progress toward achieving the goals set forth in their Proposal.

As the Companies correctly recognize, deferring recognition of incremental costs associated with AMI deployment through the establishment of regulatory assets preserves the Commission's ability "to review the prudency of those costs when the Company seeks to recover them" in future distribution rate cases. [9] Although we will address the details of cost recovery in the context of such future rate cases, we note now that we will expect Pepco and Delmarva to demonstrate at that time that they have incurred a level of costs and delivered a level of benefits that render their respective AMI projects cost-effective programs for their Maryland customers.

II. Background and Procedural History

A. Case No. 9111

On March 21, 2007, the PHI Companies each filed with the Commission an "Application for Authorization to Establish a Demand Side Management ["DSM"]

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[9] PHI witness J. Mack Wathen ("Wathen Direct") at 4.

Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group" ("2007 Applications"). The 2007 Applications set forth each Company's "Blueprint for the Future," described as "a comprehensive demand response, advanced metering and energy efficiency plan" that would "help [each Company's] Maryland electricity customers conserve energy and reduce their future energy costs," and "help to ensure the continuing reliability of electricity supply and enhance the quality of electric distribution service."[10] The Companies did not propose in their 2007 Applications any specific timetable for full-scale AMI deployment in their service territories, nor did they proffer a business case in support of any such deployment.[11] Rather, they requested authority to establish "an advanced metering infrastructure rate adjustment mechanism that will recover the costs of [each Company's] installation of advanced metering and accompanying demand response enabling equipment for its Maryland customers," and to establish "an AMI Advisory Group that will be kept apprised of the progress, status, components and development of [each Company's] AMI installation."[12]

On June 8, 2007, the Commission established a collaborative process to consider certain issues pertaining to AMI and DSM programs, including, *inter alia*, the "technical standards for and operational capabilities of advanced meters."[13] Pepco, Delmarva, BGE, Choptank Electric Cooperative, Potomac Edison Company, Southern Maryland Electric Cooperative and the Technical Staff of the Commission participated in this collaborative

[10] *In the Matter of the Commission's Investigation of Advanced Metering Technical Standards, Demand Side Management (DSM) Cost Effectiveness Tests, DSM Competitive Neutrality, and Recovery of Costs of Advanced Meters and DSM Programs*, Case No. 9111, Dkt. Nos. 13 & 14, at 1 (Mar. 21, 2007).
[11] Pepco 2007 Application at 7; Delmarva 2007 Application at 7.
[12] Pepco 2007 Application at 3-4; Delmarva 2007 Application at 3-4.
[13] Order No. 81448 at 1.

process. Process participants could not agree, however, on the appropriate technical standards for AMI.[14]

Accordingly, on September 28, 2007, we issued Order No. 81637, which, among other things, established "standards for AMI programs."[15] In that Order, we recognized that:

> the majority of benefit from AMI, which enables next generation demand response technologies with significant demand and energy saving potential, is likely to be in operational and distribution-related savings for the utilities. Of course, we also recognize that the peak load reductions occasioned by AMI and an appropriate rate structure will provide significant benefits in terms of maintaining reliable service, as well as reductions in capacity and energy costs.[16]

To maximize these expected benefits, we identified certain minimum requirements for any proposal to implement an AMI system.[17] We declined to address the appropriate cost-recovery mechanism for AMI initiatives at that time.[18]

In December, 2007, the Companies filed business cases purporting to demonstrate that AMI "is an appropriate investment for customers in Maryland."[19] Those business cases were comprised of four major components: (1) estimated operating cost savings that the Companies claimed could be realized upon AMI implementation; (2) the estimated value to customers of load reductions resulting from PHI's broad suite of DSM initiatives, including energy efficiency, direct load control, and AMI deployment, based

[14] *See* Case No. 9111, Report of the Advanced Metering Initiative/Demand Side Management Collaborative at 5, Dkt. No. 41 (July 6, 2007).
[15] Order No. 81637 at 1-2.
[16] *Id.* at 4.
[17] *Id.* at 5.
[18] *Id.* at 7.
[19] Case No. 9111, Transmittal Letter, Delmarva Power and Light Company – Business Case Filing for Automated Metering Infrastructure at 1, Dkt. No. 113 (Dec. 21, 2007); Transmittal Letter, Potomac Electric Power Company – Business Case Filing for Automated Metering Infrastructure at 1, Dkt. No. 114 (Dec. 21, 2007).

upon an analysis by *The Brattle Group*, whom PHI retained for that purpose; (3) AMI deployment costs, including capital investments and incremental operating costs for a proposed AMI system; and (4) accelerated depreciation of existing meters.[20] With those filings, the Companies renewed their requests "to approve the AMI cost recovery mechanism so that [each Company] is able to advance its planning and installation of AMI in Maryland."[21]

B. Request for Expedited Approval to Establish a Regulatory Asset

On March 26, 2009, the Companies filed a "Request for Expedited Approval to Establish a Regulatory Asset for the Deployment of AMI" ("March 2009 Request"), seeking "expedited approval for the creation of a regulatory asset to enable the deployment of [AMI] in the Pepco and Delmarva service territories in Maryland."[22] Specifically, the Companies requested approval to establish a regulatory asset "to defer the recovery of the incremental costs associated with the AMI deployment that are incurred between base rate cases."[23] As proposed, the regulatory asset would earn the respective PHI Company's authorized rate of return, and "Commission Staff and other interested parties [would] have the ability to review the level or any other aspect of the asset when the [Companies] seek to recover the deferred incremental costs in a base rate

[20] Case No. 9111, Delmarva Power and Light Company – Business Case Filing for Automated Metering Infrastructure, Dkt. No. 113 (Dec. 21, 2007); Potomac Electric Power Company – Business Case Filing for Automated Metering Infrastructure, Dkt. No. 114 (Dec. 21, 2007).
[21] Case No. 9111, Transmittal Letter, Delmarva Power and Light Company – Business Case Filing for Automated Metering Infrastructure at 2, Dkt. No. 113 (Dec. 21, 2007); Transmittal Letter, Potomac Electric Power Company – Business Case Filing for Automated Metering Infrastructure at 2, Dkt. No. 114 (Dec. 21, 2007). The Companies updated their business cases for AMI deployment in their current joint Proposal.
[22] Request for Expedited Approval to Establish a Regulatory Asset for the Deployment of AMI, Mail Log No. 115775, at 1 (Mar. 26, 2009).
[23] *Id.* at 5.

proceeding."[24] According to the Companies, the expeditious creation of a regulatory asset would "provide assurance that the PHI [Companies] will recover their prudently incurred costs associated with the deployment of AMI," and also would "enhance the ability of the PHI [Companies] to obtain federal funding for AMI pursuant to the recently enacted American Recovery and Reinvestment Act of 2009 ('ARRA')."[25] The Companies asserted that, taking into account the potential award of matching federal funding, "when factoring in the operational benefits from AMI, and not including the demand response benefits associated with AMI, the operational benefits [would] more than offset the costs of deploying AMI[.]"[26] On May 12, 2009, the Companies filed supplemental comments in further support of their March 2009 Request. The matter was set for consideration at the Commission's June 10, 2009 Administrative Meeting.

Numerous parties filed comments in advance of or following that Administrative Meeting. Commission Staff ("Staff")[27] and the Office of People's Counsel ("OPC")[28] each recommended that the Commission reject the Companies' request for expedited approval to establish a regulatory asset for the costs associated with AMI deployment. The Maryland Energy Administration ("MEA") suggested that the Commission authorize the requested establishment of a regulatory asset, subject to certain limitations, including no expenditure of funds in connection with AMI deployment until PHI had: (1) submitted a complete Smart Grid plan to include program design, proposed pricing mechanisms, consumer education and technical details; (2) satisfied the Commission through cost-

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[24] *Id.*
[25] *Id.* at 1.
[26] *Id.* at 5.
[27] No. A1617 (June 1, 2009).
[28] Mail Log No. 117120 (June 8, 2009).

benefit analysis that their plan was timely, beneficial and consistent with the public interest; and (3) received a significant DOE supporting grant to help offset the Company's AMI costs.[29] Prince George's County Executive Jack Johnson,[30] Montgomery County Council Member-at-Large George Leventhal,[31] Montgomery County Council Member Roger Berliner,[32] and Mayor Eugene W. Grant, Seat Pleasant, Maryland,[33] each filed comments in support of the Companies' request for expedited approval to establish a regulatory asset for AMI deployment costs. The Montgomery County Office of Consumer Protection ("MCOCP") requested that the Commission avoid any overlap of cost recovery for AMI deployment with cost recovery for initiatives implemented under the EmPower Maryland Energy Efficiency Act of 2008. MCOCP also "reserve[d] the right to comment further on the level of rate recovery that is cost-effective and consistent with the economic and environmental benefits realized by the consumer and community."[34]

At the June 10, 2009 Administrative Meeting, the Commission directed the Companies to file a more comprehensive, detailed description of the proposed AMI system, including technical details about the proposed infrastructure and further information about the costs associated with deployment. On June 30, 2009, the Companies made the requested filing in the form of a joint Proposal for Advanced Metering Infrastructure (AMI).[35] In a supplemental filing made on July 22, 2009, the

[29] Mail Log No. 117130 (June 8, 2009).
[30] Mail Log No. 117124 (June 8, 2009).
[31] Mail Log No. 117243 (June 15, 2009).
[32] Mail Log No. 117220 (June 12, 2009).
[33] Mail Log No. 117194 (June 11, 2009).
[34] Mail Log No. 117119 (June 8, 2009).
[35] Mail Log No. 117523 (June 30, 2009).

Companies proposed – as an alternative to their request for expedited approval of the establishment of a regulatory asset – a procedural schedule for a legislative-style hearing that would permit the Commission to issue a final order on the matter by October 2, 2009.

At its July 29, 2009 Administrative Meeting, the Commission further considered the Companies' request for expedited approval to establish a regulatory asset, or, in the alternative, a procedural schedule for a legislative-style hearing on the Proposal. Staff,[36] OPC,[37] and AARP Maryland ("AARP")[38] each submitted comments opposing the Companies' request for expedited approval to establish a regulatory asset and recommending that the Commission docket a case and establish a procedural schedule for a full evidentiary hearing on the merits of Companies' Proposal. The Apartment and Office Building Association of Metropolitan Washington ("AOBA") likewise opposed the Companies' request, and recommended, among other things, that the Commission establish a procedural schedule for and conduct "a base rate proceeding consistent with Pepco's filing of its August 6 application with DOE for federal funding."[39] MEA supported the Companies' request for a legislative-style hearing regarding AMI deployment and associated costs, stating that "[w]ith the short timeframe associated with [ARRA] stimulus funds, MEA believes that a legislative-style hearing will provide the best opportunity for stakeholders to weigh in on AMI while still being responsive to the

[36] No. A1617 Supp. (July 20, 2009).
[37] Mail Log No. 117984 (July 27, 2009).
[38] Mail Log No. 117974 (July 27, 2009).
[39] Mail Log No. 117990 at 13 (July 27, 2009).

availability of stimulus funds that could potentially support PHI's proposed AMI deployment."[40]

Following the July 29, 2009 Administrative Meeting, the Companies requested that the Commission "establish a procedural schedule to consider the Companies' proposed AMI-enabled dynamic pricing proposal in addition to addressing the Companies' joint request for regulatory assets for AMI-related costs and undepreciated meter costs."[41] The Companies further requested that such procedural schedule call "for a final order on the appropriate pricing structure for AMI-enabled dynamic pricing by December 2, 2009."[42] The Companies noted that including such a procedural schedule in its applications for DOE funding would be "consistent with the DOE's instruction to outline the approval process for elements of an application that require regulatory (Commission) approval."[43]

C. Case No. 9207

On August 5, 2009, we issued Order No. 82824, in which we denied the Companies' request for approval to establish a regulatory asset for AMI-related costs at that time, and initiated this Case to consider the Companies' AMI Proposal and, if approved, any appropriate mechanisms for the recovery of associated costs. We observed that our approval was not a necessary precondition to the Companies' pursuit of possible federal funding from DOE. And although mindful of the opportunity for federal funding, we noted that we "must and will undertake a thorough and careful review before

[40] Mail Log No. 117976 (July 27, 2009).
[41] Mail Log. No. 118115 (Aug. 3, 2009).
[42] *Id.*
[43] *Id.* at n.1.

approving programs of this cost and magnitude."[44] Our Order deemed the PHI Companies, Staff, OPC, MEA, MCOCP, AARP, and AOBA Parties of Record ("Parties") in this proceeding, and required that any Petitions to Intervene be filed by August 20, 2009.

The Parties[45] engaged in discovery forthwith, and the Companies filed the direct testimony of the following six witnesses on September 1, 2009, as revised on October 9 and November 17, 2009: William M. Gausman; George W. Potts; Ahmad Faruqui; Joseph F. Janocha; J. Mack Wathen; and J. Reed Bumgarner. On October 20, 2009, the remaining Parties filed the direct testimony of the following witnesses: Barbara R. Alexander, on behalf of AARP; Nancy Brockway, David J. Effron, and James Richard Hornby on behalf of OPC; Crissy Godfrey, Daniel Hurley, Daniel Norfolk, Thomas J. Asp and Andrew L. Afflerbach on behalf of Staff; Bruce R. Oliver on behalf of AOBA; and David R. Scott, Fred Jennings and Robert J. Howatt on behalf of MEA. The Parties filed reply testimony on November 9, 2009, and OPC filed supplemental testimony of Mr. Hornby on November 18, 2009.

In the meantime, on November 5, 2009, the Companies filed notice with the Commission that Pepco's application for a DOE grant had been selected for award negotiations.[46] Delmarva's grant application was not selected for award.[47]

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[44] Case No. 9207, Order No. 82824 at 2-3.
[45] All Parties with the exception of MCOCP actively participated in this proceeding.
[46] Case No. 9207, Dkt. No. 41 (Nov. 5, 2009).
[47] *Id.* According to an attached letter from P. Hoffman, Acting Assistant Secretary, Office of Electricity Delivery and Energy Reliability, DOE to Mr. Gausman, the fact that Delmarva's grant application was not selected for award represented "the level of competition rather than a reflection on [Delmarva's] application."

We held six days of evidentiary hearings on November 19, 20 and 23, 2009, December 14, 2009, January 5, 2010, and January 13, 2010. During the course of those hearings, we heard from nineteen witnesses for PHI, Staff, OPC, AARP, MEA and AOBA. Following the hearings, the Parties submitted initial and reply briefs on February 19, 2010 and March 1, 2010, respectively. OPC, AARP and AOBA urged that we reject the PHI Companies' Proposal, while MEA and Staff recommended that we approve the Proposal with certain modifications. It is upon this full evidentiary record that we reach the conclusions reflected in this Order.

III. The Proposal

In this proceeding, the Companies request that the Commission issue an Order that:

(1) authorizes deployment of AMI in the Companies' Maryland service territories;[48]

(2) approves "the principle of dynamic pricing coupled with AMI" and directs the Companies "to go forward with that approach," with specific dynamic pricing rates to be proposed at a later date;[49] and

(3) authorizes each Company's establishment of two regulatory assets to provide the Companies the opportunity to recover in future base rate cases (a) the incremental costs associated with AMI deployment; and (b) the undepreciated book value of the Companies' existing meters.[50]

We describe more fully below each of these three aspects of the Companies' Proposal.

[48] PHI Initial Brief at 3.
[49] Tr. 931-32 (PHI witness J. Reed Bumgarner); PHI Initial Brief at 42-43.
[50] Wathen Direct at 4; PHI Initial Brief at 1.

Advanced Metering Infrastructure

The Proposal is part of a "phased approach to implementing AMI functionality" throughout the service territories of PHI's electric distribution companies in Delaware (Delmarva), the District of Columbia (Pepco), Maryland (Pepco and Delmarva), and New Jersey (Atlantic City Electric).[51] In November, 2009, Delmarva began AMI deployment in Delaware,[52] and is scheduled to complete installation of approximately 300,000 electric and 133,000 gas meters in that state by November, 2010.[53] In December, 2009, the Public Service Commission of the District of Columbia authorized Pepco to deploy AMI in its District of Columbia service territory.[54]

In Maryland, the Companies' proposed schedule called for AMI installation in Pepco's service territory to commence in mid-2010, with a goal of completing the installation by the end of 2011.[55] Delmarva intends to begin installing smart meters in its Maryland service territory in mid-2011 – after it has concluded its Delaware roll-out – and aims to complete installation in 2012.[56] PHI proposes to replace all of the approximately 570,000 existing electric meters in Pepco's Maryland service territory, and all of the approximately 221,000 existing electric meters in Delmarva's Maryland service

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[51] Proposal for Advanced Metering Infrastructure (AMI), Case No. 9207, Dkt. No. 10 (includes "Proposal Executive Summary" and "Proposal"), Proposal at 9 (June 30, 2009).
[52] Tr. 677 (Potts). In September, 2008, the Delaware Public Service Commission approved Delmarva's request to install AMI in that state and established a regulatory asset for associated costs. *In the Matter of the Filing by Delmarva Power & Light Company for a Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency,* DE PSC Docket No. 07-28, Order No. 7420, slip op. at 5 (September 2008).
[53] Tr. 677-78 (Potts).
[54] *In the Matter of the Application of the Potomac Electric Power Company for Authorization to Establish a Demand Side Management Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group,* The District of Columbia Public Service Commission, Formal Case 1056, Order No. 15629 (December 17, 2009).
[55] Gausman Reply at 5.
[56] *Id.*

territory, with new "smart" electric meters.[57] The proposed smart meters are capable of providing a more granular measurement of electricity consumption than are the existing meters (*i.e.* daily, hourly, and 15-minute interval meter reads).[58]

The second major component of the Companies' proposed advanced metering infrastructure is an integrated communications architecture comprised of four main elements: (1) a wireless home area network ("HAN") to be provided through the use of ZigBee Smart Energy Standard, and intended to enable communications between the "smart" meter and a variety of "smart" home appliances and other devices at some time in the future;[59] (2) an underlying wireless mesh network to communicate with customers' AMI meters and distribution automation devices, and to be used, among other purposes, for collecting data from customers' meters;[60] (3) a broadband backhaul system through Verizon to bring the field data back to a substation or other field collection point, or to send information into the field;[61] and (4) at the highest level, fiber optics or high speed microwave data transmission between the substations and Central Operations, also known as the "backbone network."[62]

[57] Potts Direct at 11.
[58] Gausman Direct at 7; Proposal at 12.
[59] Gausman Direct at 39; Proposal at 16.
[60] Gausman Direct at 39; Proposal at 15-16.
[61] Gausman Direct at 39. The Companies initially intended to create their own private WiMax broadband network "to connect the AMI mesh radios and other Smart Grid systems to the rest of PHI's network." Tr. 770-71 (Potts). Following the hearings in this Case, however, the Companies informed us that they had terminated negotiations with their proposed WiMax vendor, that Delmarva instead was using Verizon Wireless in its Delaware deployment, and that the Companies would "continue to evaluate other broadband solutions that may become available." PHI Initial Brief at 40. According to Staff witness Afflerbach, using Verizon commercial broadband rather than a private WiMax network would decrease reliability, scalability and security. Direct Testimony of Staff Witness Andrew Afflerbach ("Afflerbach Direct") at 6-7. PHI confirmed that "all proposed systems will be tested prior to full implementation as suggested by Staff witness Afflerbach." PHI Initial Brief at 40.
[62] Gausman Direct at 39; Proposal at 15.

The third major AMI infrastructure component is a new Meter Data Management System ("MDMS"), which will receive the incoming metering data, store it, and perform validation, estimation, and editing of the data before making it available for billing and other purposes.[63]

The Proposal also contemplates the creation of an internal AMI Portal which presents on one screen a customer's daily energy usage and outage history.[64] The Portal would allow PHI's Customer Service Representatives and other designated personnel to communicate directly with the communications network head end system in order to request and receive on-demand information stored by smart meters, verify smart meter status and turn on or turn off a customer's electricity via a remotely activated switch in the smart meter.[65]

PHI proposes to integrate its AMI head end system, outage management system, customer billing system, customer enrollment Web site known as "My Account," and a "business events notification engine" to transfer and process outage messages received from AMI meters for use in customer outage and service restoration notifications sent via the customer's mechanism of choice, such as by e-mail or text message.[66] The Proposal includes the implementation and configuration of a Load and Rate Analysis Module, the development of a meter read relational database, and the integration of the Load and Rate Analysis Module with this database and communications network head end system to support Web-based presentation of customer electric consumption profiles.[67]

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[63] Gausman Direct at 7-8, 46; Potts Direct at 11.
[64] Proposal at 12.
[65] *Id.*
[66] *Id.*
[67] *Id.*

The Companies intend to expand their current "My Account" software to provide customers with the more detailed energy usage information uploaded from the proposed smart meters. Customers with Internet access will be able use this software to view their hourly energy consumption from the prior day.[68] Those customers without Internet access will have the ability to view daily consumption data on their monthly bills.[69]

In sum, the proposed advanced metering infrastructure provides many capabilities not currently available to the Companies or their customers. For example, it is designed to notify the Companies remotely of service outages, thereby obviating the need for customers to call their respective electric distribution companies to report outages, facilitating more efficient dispatch of restoration crews, and potentially reducing the time necessary to restore customers' service.[70] According to PHI, AMI also will allow the Companies to operate more efficiently by automatically relaying a customer's hourly energy usage to the Companies' billing system, eliminating the costs the Companies currently incur to manually read every customer's meter.[71] Additionally, AMI will provide the Companies with customer energy usage on an hourly basis, thereby enabling the implementation of dynamic pricing structures.[72]

B. Dynamic Pricing

Under a Dynamic Pricing Rider DP ("Rider DP") to their existing tariffs, the Companies propose to offer three pricing options for the Companies' residential, small

[68] Tr. 743-44 (Potts).
[69] Tr. 744 (Potts). Mr. Potts testified that 71.6% of the Companies' Maryland customers currently have Internet access. *Id.* at 744-45.
[70] Tr. 26-29 (Gausman).
[71] December 2007 "Business Case in Support of Delmarva's Blueprint for the Future Application" at 12-13; December 2007 "Business Case in Support of PEPCO's Blueprint for the Future Application" at 11.
[72] Gausman Direct at 7.

commercial, and medium commercial customers who receive electricity supply through the Companies' standard offer service ("SOS").[73] The default option would be a Critical Peak Rebate ("CPR") pricing structure, which consists of flat SOS rates, modified by the opportunity to earn credits for reducing electricity use from a customer-specific baseline during Company-declared "critical peak periods."[74] To establish each customer's baseline, the Companies would calculate "the hourly average of the customer's use during similar high cost hours for the three days with the highest use during the prior 30-day period," excluding holidays, weekends and critical peak days.[75] The Companies may declare up to 15 critical peak events on non-holiday weekdays each year from June 1 through October 31.[76] These critical peak events may last up to four hours from 2:00 P.M. to 6:00 P.M.[77] PHI witness Bumgarner testified that the Companies will make "a reasonable attempt" to inform customers of these critical peak events by 7:00 P.M. the prior evening, either through an automated phone call, e-mail, text message or combination thereof.[78] Customers also may call the Companies' customer service

[73] PHI Initial Brief at 42; Direct Testimony of PHI witness J. Reed Bumgarner ("Bumgarner Direct") at 2-3.
[74] Bumgarner Direct at 5.
[75] *Id.* at 5-6.
[76] *Id.* at 6.
[77] *Id. But cf.* Direct Testimony of MEA witness Fred Jennings ("Jennings Direct") at 9 ("[A]ctual critical peak event periods could be shorter than four hours with no indication that the customers will be notified of how long the period will last, possibly creating a situation where customers will commit to the inconvenience of managing their load for a four-hour period but the critical peak event experienced by PHI is for a shorter duration.").
[78] Bumgarner Direct at 6. Mr. Bumgarner testified that by "reasonable attempt," he means that the Companies would send a notice of an upcoming critical peak event by 7:00 P.M. the evening before the event, but that the Companies could not ensure that all customers actually receive the message. Tr. 1029-37. He also acknowledged, however, the possibility that under certain circumstances, the Companies might not be aware of a critical peak event by 7:00 P.M. the preceding evening, and that in those circumstances, the Companies would not provide the requisite notice by 7:00 P.M. Tr. 1037-38.

centers or visit the Companies' websites to learn whether a critical peak event has been declared.[79]

The second pricing option, proposed to be available on an opt-in basis, is a Critical Peak Pricing ("CPP") structure, whereby customers would pay a higher rate per kilowatt-hour used during Company-declared critical peak periods, with all other consumption priced below SOS rates between June 1 and October 31 of each year.[80] For the other seven months of the year, CPP customers would pay SOS rates.[81] According to the Company, the CPR and CPP dynamic pricing structures are designed to provide customers "strong incentives to reduce consumption during the times when the cost of producing electricity is highest," thereby generating benefits for customers as well as broader societal benefits.[82] Under the third pricing option, customers could opt out of CPR and remain on flat SOS rates.[83]

Both the CPR and CPP rates are based upon PHI's calculation of a "Base Critical Peak Price" ("Base CPP"), which contains an energy component and a capacity component.[84] For purposes of the Proposal, PHI calculated the Base CPP energy component as the average of the 60 highest PJM Locational Marginal Prices during the Summer of 2008, adjusted for line losses to the user level.[85] The Companies based the capacity component on the average PJM base residual auction results for 2011-12 and 2012-13, adjusted for line losses to the user level and spread over the 60 potential critical

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[79] Bumgarner Direct at 6-7.
[80] Bumgarner Direct at Exh. JRB-1.
[81] PHI Initial Brief at 45.
[82] Bumgarner Direct at 4.
[83] *Id.*
[84] *Id.* at 7.
[85] *Id.* at 7-8.

peak period hours.[86] These calculations yielded a Base CPP of $1.25 per kWh, after disregarding minor differences due to voltage levels.[87] The Proposal adopts this figure as the CPR rate – that is, for every kilowatt hour of load reduction during Company-declared critical peak periods, a customer on the default CPR rate schedule would receive a credit of $1.25.[88] According to the Company, "[t]he nature of this default option virtually guarantees that the [c]ustomer will be better off if responding to the price, and will be no worse off if not responding."[89]

For purposes of the CPP rate, Mr. Bumgarner adjusted the Base CPP upward 25 cents to send a strong price signal to CPP customers.[90] The proposed CPP rate option is designed to be revenue neutral for the Companies' residential customers, which, according to PHI witness Faruqui, means that "the *average* customer's electric bill would not change if he/she switched from his/her current rate to the new CPP rate."[91] In other words, the Companies contend that initially, "[r]oughly half of the customers would be expected to experience bill increases (the customers with 'peakier' load shapes), and the other half could expect bill savings (customers with flatter load shapes.)"[92] Dr. Faruqui predicts that as customers reduce energy use during critical peak periods in response to the CPP rate, more customers on that rate schedule will see bill savings.[93]

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[86] *Id.* at 8.
[87] *Id.* As with all rates in the Companies' Proposal, this Base CPP rate is intended only to illustrate the manner in which the Companies would calculate their dynamic rates when they initiate Rider DP. The Companies intend to propose actual CPR and CPP rates at a later time. Tr. 963 (Bumgarner).
[88] Bumgarner Direct at 5, 9.
[89] *Id.*
[90] Tr. 952 (Bumgarner).
[91] Faruqui Direct at 11 (emphasis added).
[92] *Id.*
[93] *Id.*

After October 31 of each year, the Companies would compare by rate class the amount billed between June 1 and October 31 under the CPR and CPP programs with the amount that would have been billed for the same consumption using SOS rates, and would adjust the CPR and CPP rates for the following year accordingly.[94] The Companies also would adjust the following year's CPR and CPP rates for "any over or under monetization [that the Companies] received from PJM for those supply side benefits."[95] The Companies would file these adjusted rates on March 1 of each year.[96] Under the Companies' Proposal, a customer's opportunity to change his or her rate option would be limited to once each year, following the March 1 filing, provided that the customer gives notice to PHI at least 30 days before the June billing cycle.[97]

C. Cost Recovery

Under the Proposal, the Companies each seek approval to establish two regulatory assets. The first regulatory asset would include the incremental costs associated with AMI (discussed more fully in section IV.A. below).[98] The Companies have been deferring AMI-related costs incurred since 2007, although the Commission has not approved either a specific AMI proposal or the establishment of a regulatory asset for costs associated with any such proposal.[99] The Companies now request that we approve

[94] Bumgarner Direct at 9-10 (On page 9 of his Direct Testimony, Mr. Bumgarner described this period as May 1 through October 31. Based upon Exhibit JRB-1 and other PHI witness testimony, it appears that the intended period is June 1 through October 31.); Tr. 999 (Bumgarner).

[95] Tr. 999 (Bumgarner).

[96] Bumgarner Direct at 9-10. PHI concedes that its current description of its annual true-up process is not yet fully developed. Tr. 1000 (Bumgarner) ("I understand [the annual true-up process] needs work.").

[97] Bumgarner Direct at 4.

[98] PHI Initial Brief at 48.

[99] The Companies are relying upon Order No. 81637 in Case 9111. PHI Initial Brief at 49; Tr. 204-05 (Wathen).

the establishment of a regulatory asset for those previously incurred costs.[100] In addition, the Companies propose to include in that regulatory asset the following costs, which they claim are incremental to their AMI Proposal:

(1) Depreciation expense for the new smart meters, offset by depreciation expense for existing meters currently in rate base;
(2) Leasing costs for computer hardware associated with the Meter Data Management System;
(3) Amortization of AMI-related software; and
(4) Incremental AMI labor and consulting costs.[101]

The Companies propose to include any known and measurable utility cost savings resulting from AMI deployment as an offset to the costs in the regulatory asset, and to receive a return at their respective authorized rates on the net of the expenses and savings reflected in the regulatory asset, amortized over a period to be determined by the Commission.[102] The Companies claim that establishing a regulatory asset is necessary to allow them the opportunity to recover prudently incurred costs that occur outside of the test period evaluated in a rate case.[103] They also claim that regulatory asset treatment of these costs is essential to maintain their investment grade credit rating in today's credit markets.[104]

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[100] Wathen Direct at 5-6.
[101] Proposal Executive Summary at 25; Wathen Direct at 8.
[102] PHI Initial Brief at 48; Wathen Direct at 6, 8-9. PHI witness Wathen identified meter-reading and meter-reading related savings as operational savings that would be included in the regulatory asset as offsets to incremental AMI costs. Tr. 193-94.
[103] Wathen Direct at 6.
[104] PHI Initial Brief at 47-48; Wathen Direct at 10-14.

The second regulatory asset would include the net book value of existing meters that are not fully depreciated (also discussed more fully in section IV.A. below), amortized over a future period, which PHI proposes should be fifteen years.[105]

IV. The Companies' Business Cases in Support of the Proposal

A. Projected Costs

PHI projects that capital expenditures for the initial deployment of AMI in Maryland will total $137,700,000 for Pepco (offset by $68.3 million of the DOE grant award, for a net cost of $69,400,000) and $51,025,000 for Delmarva.[106] These projected expenditures include the cost of: (1) the AMI meters, remote connect/disconnect switches for certain meters, communication modules (network interface cards) and associated installation labor; (2) the communications network infrastructure, including associated installation costs; and (3) each Company's respective allocated share of PHI's total costs for the meter data management system and AMI network management system, which includes costs associated with software applications, systems integration and computer hardware that the Companies contend are necessary to support AMI.[107] PHI's cost estimates are based upon what PHI describes as "firm contract prices" with its vendors that apply to the Companies' AMI deployment in their Maryland service territories.[108] According to Company witness Potts:

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[105] Wathen Direct at 9-10; PHI Initial Brief at 50-51. Because customers will continue paying the existing meter costs in their rates, the Companies propose that the depreciation expense of the current meters as reflected in rates be used as an offset to the depreciation expense of the new AMI meters. Reply Testimony of PHI witness J. Mack Wathen ("Wathen Reply") at 3.

[106] Gausman Direct at Exhs. WMG-1, WMG-2. Total projected deployment costs for Pepco increased from approximately $127.7 million to $137.7 million due to a requirement under the DOE Smart Grid Investment Grant that the Company's contractors pay prevailing wage rates. Tr. 91-92 (Gausman).

[107] Gausman Direct at Exhs. WMG-1, WMG-2; Proposal at 42-43.

[108] Gausman Direct at 9.

> These contracts are for initial installations in Delaware, however, the contracts are structured so that they can be expanded to include all of PHI's operating utilities service territories, including Pepco and Delmarva Maryland service territories. By structuring these contracts in this manner the Company was able to obtain price benefits from the larger scale and reduce the potential cost of integrating different work management systems for meter deployment into the overall AMI system architecture. Each vendor's pricing reflects the volume buying power of PHI across its combined service territories, resulting in a lower price for the overall system than if the system were purchased solely for only one of the PHI jurisdictions. Although the unit prices for the meters that would be purchased for Maryland would be obtained at this lower price there was no commitment made to purchase these meters.[109]

Also included in the Companies' deployment cost projections are "contingency" amounts of approximately $5.2 million for Pepco and approximately $4.9 million for Delmarva (representing approximately 6% of each Company's projected AMI capital investment in Maryland). The Companies contend that they included these contingency amounts "as a way to help manage the current uncertainty around the AMI cost estimate."[110]

In addition, the Companies have projected annual post-deployment O&M costs that they have identified as incremental to the Proposal: $1,038,000 for Pepco and$431,000 for Delmarva, based upon a projected 15-year AMI useful life.[111] A table

[109] Potts Direct at 20-21.
[110] Proposal at 42.
[111] *Id.* at 26, 28; *see also* Potts Direct at 14 (business cases include ongoing incremental O&M costs). We note that these post-deployment O&M cost projections are substantially lower than those of BGE, which projected incremental post-AMI deployment O&M costs of $353 million over a projected 15-year program life. *See* Case No. 9208, Order No. 83410 at 17-18 (June 21, 2010) (citing testimony of BGE witness Butts at 27; BGE Initial Brief at 4).

setting forth the projected initial deployment costs and incremental post-deployment O&M costs included in the Companies' business cases is reproduced below:[112]

Line	AMI System Components	Initial Deployment Costs Only, $ in 000s Pepco Maryland	Initial Deployment Costs Only, $ in 000s Delmarva Maryland
1	Meters, including installation cost	$ 105,083	$ 38,256
2	Communications Network, including Installation Cost	$ 3,620	$ 1,509
3	AMI Network Management System and Meter Data Management System	$ 13,762	$ 6,328
4	Contingency	$ 5,211	$ 4,932
	Total Capital Expenditures	$ 127,676	$ 51,025
	AMI System Incremental Cost to Operate	Annual Estimated Costs After Deployment, $ in 000s Pepco Maryland	Annual Estimated Costs After Deployment, $ in 000s Delmarva Maryland
5	MDMS Software Maintenance & License Fees	$ 108	$ 42
6	MDMS Hardware Leasing	$ 295	$ 114
7	AMI Network Management System O & M	$ 346	$ 132
8	Communications Network Infrastructure O& M	$ 289	$ 143
	Total Incremental Cost to Operate	$ 1,038	$ 431

The Companies also included in their business cases costs deferred during the "start up" phase of the Companies' proposed AMI project.[113] According to PHI, as of September 30, 2009, Pepco and Delmarva had incurred $1.753 million and $668,000, respectively, of incremental costs related to the Companies' AMI initiative on a Maryland jurisdictional basis.[114] The Companies contend that these costs "are specifically identifiable expenses that would not exist but for the AMI project in preparing for AMI."[115] PHI witness Wathen further explained:

[112] Proposal at 26, 28. As noted above, the total capital expenditures for Pepco increased to $137,700,000 as a result of prevailing wage adjustments required under the DOE grant award.
[113] Potts Direct at 5, 12, 14.
[114] Tr. 191 (Wathen); PHI Initial Brief at 49 n.7.
[115] Tr. 156 (Wathen).

> They include some of the obvious ones, contractor expenses have been hired to help develop software and so forth or contractors install, those kinds of things. Internal labor is an example. If we took an existing employee and assigned them to the AMI project but did not backfill the position for the job that they used to do, it would not be incremental, and that's the level at which we track these costs.[116]

Finally, the Companies' business cases include recovery of the net book value of the Companies' existing meters in Maryland, which will be removed and disposed of upon installation of the new smart meters.[117] As of June 30, 2009, the net book value of those meters was $97.5 million for Pepco and $16.3 million for Delmarva.[118]

There are a number of additional costs inherent in this project, or that can be expected to arise from it, that are not included in the Companies' business cases, however. For example, neither the Companies' deployment capital cost projections nor their post-deployment O&M cost projections include a line item for costs associated with the type of comprehensive customer education program that the Parties agree will be critical to achieve the sustained changes in customer behavior that will be necessary to

[116] Tr. 156-57 (Wathen). *See also* Dkt. No. 66, Data Response 1-11 (Jan. 12, 2010) (itemizing such costs incurred in 2007 and 2008).
[117] Potts Direct at 14; Tr. 168-69 (Wathen).
[118] Wathen Direct at 9. In response to an in-hearing data request, the Companies explained that the undepreciated value of meters can differ between utilities based upon factors including, among others, the timing of meter purchases and meter retirements; different depreciation rates in effect for each utility; different jurisdictional allocations between utilities; differences in the types and costs of meters installed by the utilities over time (*e.g.*, Pepco has nearly 92,000 time of use (TOU) meters installed, while Delmarva has very few customers with TOU meters); and differences in the utilities' accounting methodology for associated labor costs.

realize the level of supply-side benefits the Companies predict.[119] The Companies concede they have not yet developed a plan for such a comprehensive customer education program.[120] According to PHI witness Potts, the Companies' capital deployment cost projections include $1.00 per customer for "customer communication," which he described as letters to be sent to residential customers' homes one-to-four weeks before the customer's meter is replaced, as well as communications such as "door hangers" to make arrangements to gain access to the customer's home, if necessary, and to notify the customer once the meter exchange is complete.[121] PHI relies on the "contingency" funds allocated to each Company to cover the cost of additional customer education, which Mr. Potts projects could reach $5.00 per customer.[122]

The Companies also recognize that systems are evolving that would improve their ability to provide customer information to third parties (with customer consent), and "would need to be designed in the system architecture at an additional cost not included in the current business case."[123] The Companies likewise have not accounted in their business cases for the cost of ZigBee range extenders that may be necessary to enhance transmission from customer's smart meters, or for "in-home displays," such as those used in the BGE pilot program on which PHI relies, that could provide customers with real-

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[119] *See, e.g.*, Gausman Reply at 11; PHI Reply Brief at 39 ("The Companies generally agree with the parties regarding the importance of customer education."); MEA Initial Brief at 28-31 (discussing the importance of a "robust customer education plan"); AARP Initial Brief at 26-28 (discussing its belief that PHI has "woefully" under-funded its customer education budget); OPC Initial Brief at 33-34 (a "substantial customer education effort" will be necessary in the event we approve the Proposal); Staff Initial Brief at 8, 15 (describing customer education as "critical for the success of the AMI proposal").

[120] Gausman Reply at 11-12; Tr. 224-26 (Faruqui); Tr. 725-26 (Potts).

[121] Tr. 678-79 (Potts).

[122] Tr. 682-84 (Potts). *See also* PHI Reply Brief at 39-40 & n.34 (estimating that such an expense would absorb approximately $2.9 million of Pepco's $5.2 million contingency fund and $1.1 million of Delmarva's $4.9 million contingency fund); Tr. 621 (Jennings) (identifying $5.00 per customer as a proxy for the cost of a high-end customer education program).

[123] Reply Testimony of PHI Witness George W. Potts ("Potts Reply") at 10-11.

time price signals.[124] Nor do their business cases include the cost of the ZigBee-enabled appliances that they predict ultimately will be capable of communicating with the proposed smart meters, thereby enhancing customers' ability to effectively manage their energy use.[125] And since the Proposal contemplates a 15-year project life post-deployment – which Staff recommends should be reduced to 10 years – the business cases do not account for the likelihood that the new smart meters will need to be replaced one or more times before the existing meters would have reached the end of their useful lives.[126]

B. Projected Operational Benefits

The Companies project that AMI's enhanced functionality will produce savings in their electricity distribution operations in Maryland, which they will pass on to their Maryland customers. Meter-reading savings is the largest among these anticipated operational benefits. With the full deployment of AMI, the Companies expect that all of their Maryland customers will have meters that can be read remotely, and that the Companies no longer will need meter readers or associated supervisory personnel to perform that function.[127]

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[124] Tr. 738-39 (Potts).

[125] Tr. 1279-82 (Afflerbach); *cf.* Tr. 754 (Potts).

[126] *See* Tr. 150 (Wathen) (the average life of a new, existing meter is approximately 30 years); *see also* Direct Testimony of AOBA Witness Bruce R. Oliver ("Oliver Direct") at 18-19 (Pepco's assumption of a 15-year life for AMI equipment is "highly speculative" and the Company's use of that period in its cost-benefit analysis "avoids recognition of the fact that in approximately 15 years Pepco must expect to replace all of its AMI meters, even though it's [sic] presently existing non-AMI meters would still have nearly 13 years of expected life remaining at that time.").

[127] Proposal at 29. Although Pepco has more than two-and-one-half times the number of electric meters in its Maryland service territory as Delmarva has, the projected annual meter-reading savings for both Companies is nearly the same (approximately $3.3 million per year for Pepco, and approximately $3.1 million per year for Delmarva). According to PHI witness Potts, Delmarva has its own union meter readers, with associated pension, health care, and other related costs, while Pepco uses contractors. Tr. 668-69, 673.

Additional projected operational benefits include, among others, savings from the ability to remotely connect and disconnect electric service, thereby avoiding the need for Company personnel to conduct associated field visits,[128] and savings from a substantial reduction in the volume of "exceptions" currently addressed by the Companies' billing department, such as those related to estimated bills.[129] PHI also expects the increased accuracy of its meter reads and the greater amount of information available to its customer service representatives to reduce customer complaints, and will enable the Companies to reduce staffing in their "complaint handling group[s]" by one full-time equivalent.[130] Additionally, the Companies expect their AMI systems to significantly improve their knowledge of customer outage status, thereby reducing the costs associated with responding to outages that have already been restored, for instance, or that were caused by problems on the customer side of the meter or in the customer's home (which the Companies term "asset optimization").[131] The Companies' full complement of projected annual operational savings is summarized below: [132]

[128] PHI Witness Potts testified that annual savings attributable to remote disconnections for nonpayment are projected to be $670,000 for Delmarva and $1,694,000 for Pepco. Tr. 673-74. PHI acknowledged that current Commission policy requires a field visit prior to disconnecting service for nonpayment. The Companies confirmed that they "currently follow and will continue to adhere to the Commission's termination requirements[,]" and that "[a]ny changes to the current reconnection/disconnection policies will be reviewed and considered by the Commission prior to implementation." PHI Initial Brief at 21. *See also* Tr. at 675-76 (Q: I just want to be sure the company's position is you're going to continue to send people out when you turn off unless and until the Commission issues an order changing its rules? A: That is correct, sir.").

[129] Proposal at 29-30.

[130] *Id.* at 31.

[131] *Id.* at 30-31.

[132] Potts Direct at 6-7; PHI Initial Brief at 21.

		Current Forecast In Projected 2009 Dollars, $ in 000s Maryland PEPCO	Current Forecast In Projected 2009 Dollars, $ in 000s Maryland Delmarva
Line	Benefit Category		
1	Eliminate Manual Meter Reading Costs	$ 3,282	$ 3,103
2	Implement Remote Turn-on/Turn-off Functionality	$ 2,259	$ 895
3	Improve Billing Activities	$ 1,247	$ 291
4	Reduce Off-Cycle Meter Reading Labor Costs	$ 754	$ 427
5	Asset Optimization	$ 1,301	$ 188
6	Reduce Expenses Related to Revenue Protection	$ 33	$ 29
7	Eliminate Hardware, Software, Maintenance and Operations Cost for the Itron Handheld Data Collection System	$ 143	$ 59
8	Reduce Volume of Customer Call Types Related to Metering	$ 0	$ 19
9	Improve Complaint Handling	$ 70	$ 16
10	Total	$ 9,089	$ 5,027

As discussed at greater length in subsection IV.D below, the Companies have calculated that, on a present value revenue requirements ("PVRR") basis, over a projected 15-year life of the project, operational savings will cover $56.2 million of the projected $73.7 million cost of the project for Delmarva, and will cover $95.0 million of the projected $115.6 million cost of the project for Pepco (reduced by a 50% matching DOE grant).[133]

C. Projected Supply-Side Benefits

In addition to projected operational benefits, the Companies' business cases rely on anticipated "supply-side" benefits the Companies predicated on projections about the extent to which their customers will reduce electricity use during critical peak periods in response to the proposed CPR and CPP dynamic pricing structures, and the extent to which customers will reduce their overall energy use as a result of access to the more

[133] Potts Direct at 12-13.

granular information available through AMI. According to PHI witness Faruqui, reduction in peak time use in response to the proposed dynamic pricing tariffs will benefit customers in two primary ways. First, it will reduce or offset the amount of capacity, energy, and ancillary services that Pepco and Delmarva must purchase on behalf of their customers.[134] Second, it will depress wholesale market prices for energy and capacity, at least for the first few years, and those savings will be passed on to customers.[135]

With respect to avoided capacity costs, the Companies claim that they can "monetize the value of capacity reductions through the PJM demand response market," or alternatively, "avoid purchasing as much capacity from generators as they would in the absence of dynamic pricing."[136] They also can avoid purchasing as much energy from suppliers during high-priced periods as they otherwise would.[137] Dr. Faruqui testified about the various ways in which the Companies could monetize capacity and energy savings in the PJM capacity and energy markets, but the Companies have not yet settled on the manner in which they would do so.[138] According to OPC witness Hornby, this "failure to specify the method they will use to monetize the reductions in peak load resulting from their dynamic pricing proposals" contributes to "considerable uncertainty" regarding the Companies' supply-side benefit projections.[139] In Mr. Hornby's view,

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[134] Faruqui Direct at 4.

[135] *Id.* Market price impacts and their effect on customer costs were estimated based upon an earlier *Brattle Group* study performed for PJM and the Mid-Atlantic Distributed Resources Initiative ("MADRI"). The Companies assume that price mitigation benefits will expire in four years as the energy market adjusts to the reduced demand by, for example, delaying the construction of new plants or accelerating the retirement of inefficient generators. PHI Initial Brief at 23-24; Faruqui Direct at 6 & Exh. AF-2 (as amended).

[136] Faruqui Direct at 7.

[137] *Id.*; Tr. 71-72 (Gausman); PHI Initial Brief at 31.

[138] Faruqui Direct at 21-22;

[139] Direct Testimony of OPC witness J. Richard Hornby ("Hornby Direct") at 6.

"[d]ynamic pricing will not produce the maximum reductions in costs if the Companies do not actively bid those reductions into PJM wholesale markets."[140]

The extent to which projected supply-side benefits would be realized depends, in substantial part, upon the extent to which the Companies' customers reduce their electricity use during critical peak periods in response to the Companies' proposed dynamic pricing structures. The Companies rely upon Dr. Faruqui's projections in that regard, and Dr. Faruqui relied, in turn, upon a Pricing Impact Simulation Model ("PRISM") originally developed in California, but adapted to the results of BGE's Summer 2008 dynamic pricing pilot.[141] The BGE pilot differed in many respects from the PHI Companies' proposal here, however. For example, it involved incentive payments to participants not contemplated in the Proposal, different dynamic pricing structures and rates, and enabling technologies not included in PHI's Proposal.[142] And Dr. Faruqui did not adjust his analysis to account for potentially material differences between BGE pilot participants and PHI customers, such as differences in average income levels, educational levels, average premise square footage, or certain other housing characteristics.[143]

Although PEPCO conducted its own dynamic pricing pilot in the District of Columbia, the Companies did not rely on those pilot results for at least two reasons. First, according to Dr. Faruqui, the results of that pilot were not available when the

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[140] *Id.*

[141] Faruqui Direct at 5, 9; Tr. 292-93 (Faruqui). Dr. Faruqui calibrated the PRISM model in this way because he believed that "due to regional similarity, it is likely that Pepco and Delmarva's Maryland customers are more similar to BGE's Maryland customers than they are to the California customers who participated in the original pilot upon which PRISM is based." Faruqui Direct at 9-10.

[142] *See* Case No. 9208, Order No. 83410 at 11-16 (June 21, 2010).

[143] Tr. 242-45.

Companies filed their testimony in this Case.[144] Second, Dr. Faruqui noted what he believed to be important differences between "social demographic data" for the District of Columbia and Maryland. For example, he testified that "[t]he percent of single family homes in Maryland is about two-thirds, whereas the fraction in the District of Columbia is about one-fifth."[145] Further, "[t]he saturation of central air conditioning is also hugely different, and there are other differences in terms of the size of houses and so on."[146]

The 2008 BGE pilot was limited to residential customers; no commercial customers were involved. Dr. Faruqui assumed that eligible commercial customers would reduce peak demand at 50% of the rate expected for residential customers – an assumption he testified is supported by the findings of a California pilot program conducted in 2003 and 2004, [147] but that he admitted is "more imprecise" than projections for residential customers.[148] For non-residential customers, Dr. Faruqui limited his analysis to SOS customers with peak demand up to 600 kW. He did not model impacts for small commercial customers, because, he said, "recent experiments have not found these customers to be responsive to dynamic pricing in the absence of enabling technologies (such as programmable communicating thermostats)."[149]

The Companies also did not model impacts for customers who purchase their electricity supply from third-party suppliers,[150] as the Companies do not intend to offer

[144] Tr. 292.
[145] Tr. 293.
[146] *Id.*
[147] Faruqui Direct at 15-16; Tr. 227 (Faruqui).
[148] Tr. 241.
[149] Faruqui Direct at 13.
[150] *Id.* at 19.

dynamic pricing to those customers at this time.[151] Nor did they assess the extent, if any, to which their dynamic pricing proposal might affect the number of PHI customers who choose to receive their electricity supply from competitive suppliers.[152]

For purposes of his customer participation projections, Dr. Faruqui assumed that 55% of residential customers would remain on the default CPR rate, 20% would opt into the CPP rate and 25% would opt to remain on SOS rates.[153] Of the eligible commercial customers, Dr. Faruqui estimated that 65% would remain on the CPR rate, 10% would opt into the CPP rate and 25% would opt to remain on SOS rates.[154] Additionally, Dr. Faruqui assumed that PHI would call 10 of the potential 15 critical peak periods, and that each critical peak period would last for the full four hours.[155]

Based, in part, upon these assumptions, Dr. Faruqui concluded that an "average" PHI customer would reduce peak time demand in response to dynamic pricing as follows:[156]

In kWh/hr

	CPP	CPR
Pepco		
Residential	0.53	0.48
Residential Time of Use	0.95	0.86
Medium Commercial & Industrial	5.19	4.80
Delmarva		
Residential	0.40	0.37
SGS II[157]	3.51	3.23

151 Tr. 966 (Bumgarner).
152 Tr. 251-52 (Faruqui).
153 Faruqui Direct at 5.
154 *Id.* at 5-6.
155 *Id.* at 12.
156 *Id.* at Exhs. AF-8 and AF-9 (as amended).
157 Schedule SGS II includes small general service customers with a peak load contribution capacity of 60 kW or more. Delmarva Tariff No. 12, Second Revised Leaf, at 61.

Dr. Faruqui estimated avoided capacity and energy costs by multiplying what he projected to be the extent of PHI's customer participation in response to dynamic pricing by his estimate of what wholesale capacity and energy costs will be during the estimated 15-year life of the project.[158] He projected that by 2025, dynamic pricing would achieve a reduction in peak demand in Maryland of 202 MW for Pepco and 64 MW for Delmarva.[159]

The Companies further predict that customers would reduce their overall energy consumption by 1.5% annually during non-critical peak hours as a result of the more detailed information about their energy consumption enabled by AMI that the Companies plan to make available to their customers.[160] Dr. Faruqui claimed that the 1.5% energy conservation estimate reflects a figure the Companies believe they can achieve.[161] He testified that such a projection is supported by studies that involved a variety of in-home displays,[162] but conceded that such in-home displays are not included in the Companies' business cases.[163] OPC,[164] AARP,[165] and Staff[166] each contend that the Companies have provided little or no support for their 1.5% energy conservation effect projection, and

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[158] Faruqui Direct at 6. Dr. Faruqui used the net cost of new entry, or "net CONE," to estimate the future value of capacity in the PJM wholesale market. Faruqui Direct at 25; Tr. 273. Those figures were approximately $57 per kW/year for Pepco and $54 per kW/year for Delmarva. Direct Testimony of Daniel J. Hurley ("Hurley Direct") at 13. To estimate future energy prices, the Companies used the 2008 average wholesale market prices of $0.085 per kWh for Pepco and $0.081 per kWh for Delmarva. *Id.* at 15.
[159] Faruqui Direct at 6 (as amended).
[160] *Id.* at 8; Reply Testimony of Dr. Ahmad Faruqui ("Faruqui Reply") at 11; Tr. 279-80 (Faruqui); PHI Initial Brief at 28-30.
[161] Tr. 280-281 (Faruqui).
[162] Faruqui Reply at 11; Tr. 280-81.
[163] Tr. 281-82 (Faruqui).
[164] Direct Testimony of OPC Witness Nancy Brockway ("Brockway Direct") at 21-26.
[165] Direct Testimony of AARP Witness Barbara R. Alexander ("Alexander Direct") at 39-43.
[166] Rebuttal Testimony of Staff Witness Daniel J. Hurley ("Hurley Rebuttal") at 7.

recommend that the Companies' business cases be modified to include the cost of in-home displays.

D. Cost-Benefit Analyses

To demonstrate the Proposal's cost-effectiveness, the Companies conducted a Present Value Revenue Requirements ("PVRR") analysis based on the Proposal's projected costs and benefits. The PVRR methodology is intended to provide an evaluation of the incremental impact of costs and benefits of the AMI investment on PHI customers.[167] A revenue requirement is calculated on an annual basis using projected capital and O&M expenses, as well as projected operational savings.[168] The net present value of the stream of annual revenue requirements is then calculated using a discount rate equal to the respective Company's allowed weighted average cost of capital.[169] The revenue requirement analysis begins in the first year following full AMI deployment, and continues over a 15-year projected life of the project.[170]

The Companies' PVRR cost-benefit analyses are summarized below:[171]

[CHART TO FOLLOW ON NEXT PAGE]

[167] Direct Testimony of PHI Witness Joseph F. Janocha ("Janocha Direct") at 3.
[168] *Id.*
[169] *Id.*
[170] *Id.*
[171] Potts Direct at 13 (as amended); PHI Initial Brief at 17.

	Delmarva	Pepco
	Without DOE Grant Scenario (Dollars in Millions)	50% DOE Grant Scenario (Dollars in Millions)
Projected Cost PVRR	$73.7	$115.6
Projected Energy Delivery Operating Benefits PVRR	$56.2	$95.0
Projected Customer Savings in Reductions in Peak Load	$66.8	$216.6
Projected Benefits & Savings PVRR	$123.0	$311.6
Ratio of Projected Benefits & Savings PVRR	1.669	2.696
Projected Capital Expenditure	$51.0	$67.6

PHI contends that projected benefits-to-costs ratios of 1.669 for Delmarva and 2.696 for Pepco (after taking the DOE grant into account) demonstrate the Proposal's cost-effectiveness for each Company's customers.[172] Staff witness Asp opined that a 10-year period is a more appropriate estimate of the smart meters' life expectancy than the Companies' 15-year useful life projection.[173] Although PHI did not object to the use of a 10-year useful life projection for depreciation purposes,[174] the Companies declined to adjust the 15-year extended timeframe for their PVRR analyses.[175]

Staff also opposed the Companies' proposal to accelerate depreciation of the existing meters, arguing that the depreciation of those meters already is reflected in current rates, and that the question of accelerated depreciation should be addressed in the

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[172] PHI Initial Brief at 17. The Companies accepted OPC witness Effron's recommendation that interest on the deferred balance should be calculated on a net-of-tax basis, and adjusted the PVRR analysis accordingly. Reply Testimony of PHI Witness Joseph F. Janocha ("Janocha Reply") at 6; PHI Initial Brief at 18.

[173] *See* Direct Testimony of Staff Witness Thomas Joel Asp ("Asp Direct") at 31.

[174] Potts Reply at 10; PHI Initial Brief at 18.

[175] Potts Reply at 6.

Companies' next depreciation cases.[176] The Companies disagreed, arguing that once the existing meters are removed from service, they are removed from Electric Plant in Service in the Companies' accounting records and are no longer subject to depreciation.[177] The Companies therefore do not propose depreciation of those assets, accelerated or otherwise.[178] Rather, they propose that once the existing meters are removed from service, the undepreciated costs of those meters should be placed into a regulatory asset, to be amortized over 15 years, and to be reflected in rates at the time of each Company's next base rate case.[179] The Companies further propose to use the depreciation expense of the existing meters as reflected in rates as an offset to the depreciation expense of the new AMI meters.[180] Therefore, according to Company witness Janocha, the Companies' PVRR analyses, which include only the incremental revenue requirements associated with the recovery for the legacy meters over 15 years, rather than over the remaining life of those meters, appropriately takes the existing meter costs into consideration.[181]

Staff calculated revised PVRRs assuming a 10-year benefit stream and excluding the costs Staff contends were associated with accelerated depreciation of the legacy meters ("Staff's base case"). With those assumptions, Pepco's cost-benefit ratio, inclusive of DOE funding, declined from approximately 2.7 to 2.53, and Delmarva's cost-benefit ratio declined from approximately 1.67 to 1.39.[182]

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[176] Hurley Direct at 5.
[177] Wathen Reply at 3.
[178] *Id.*
[179] *Id.*
[180] *Id.*
[181] Janocha Reply at 5-6.
[182] Hurley Direct at 19.

Additional sensitivity analyses conducted by Staff further illustrate the degree to which the strength of the Companies' business cases rely upon their assumptions about supply-side benefits, as follows:[183]

Sensitivities Based on 10-Year Benefit Stream	**Pepco TRC[184] (with DOE Funds)**	**Delmarva TRC**
No Price Mitigation Benefits	2.16	1.36
50 Percent Less Capacity Revenue	2.08	1.18
50 Percent Less Energy Revenue	2.28	1.25
50 Percent Less Capacity and Energy Revenues	1.83	1.04

OPC witness Hornby performed a similar sensitivity analysis for Pepco, but based upon the Company's projection of a 15-year benefits stream and not taking into account the cost-mitigating effect of the DOE matching grant.[185] He concluded that under those conditions, Pepco's benefits-to-costs ratio would decline to 1.4 if the Company does not bid any reductions in peak load into the PJM wholesale markets.[186] Furthermore, if reductions in peak load and annual use were 50% of those assumed by Pepco, and if capacity values were 50% of those the Company assumed in its business case, the Company's benefits-to-costs ratio would decline to 0.9.[187]

V. Analysis

A. Cost-Effectiveness

[183] *Id.*; Hurley Rebuttal at 3.
[184] TRC stands for "Total Resource Cost," a benefits-to-costs ratio.
[185] Hornby Direct at 21-22; Tr. 1214-16.
[186] Hornby Direct at 21-22.
[187] *Id.* at 22.

In considering this or any other AMI proposal, we must evaluate whether the proposed technology is "cost-effective in reducing consumption and peak demand of electricity in Maryland."[188] As we have stated in other contexts, a TRC or other cost-benefit calculation is not the only consideration in such an analysis:

> The Commission views cost-effectiveness as requiring a real rate of return on ratepayers' investment, measured by meaningful bill savings for all ratepayers, and we do not view the outcomes of the TRC or other California Manual tests as dispositive or binding. . . . [T]he analysis of cost-effectiveness will be informed by the impact of these programs on ratepayers' utility rates, as well as the allocation of costs and the achievement of energy savings, but at the end of the day we must be persuaded that the individual and collective benefits are worth the ratepayers' investment.[189]

Thus, our cost-effectiveness analysis begins, but does not end, with the Companies' projections of a benefits-to-costs ratio of 2.696 for Pepco and 1.669 for Delmarva. On the surface, at least, the business cases for both Companies appear to demonstrate that the financial benefits expected to inure to ratepayers over the Proposal's projected life will outweigh the Proposal's costs. That is particularly true for Pepco, because the capital costs associated with AMI deployment in that Company's Maryland service territory are expected to be substantially reduced by a matching Smart Grid Investment Grant.

As the above-referenced sensitivity analyses make clear, however, the Companies' business cases rely, to varying degrees, on projected supply-side benefits.

[188] 2008 Md. Laws, ch. 131 § 2; *see also* Public Utility Companies Article ("PUC") § 7-211(f) and (i).
[189] *In the Matter of Potomac Electric Power Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPower Maryland Energy Efficiency Act of 2008,* Case No. 9155, Order No. 82385 at 4-5 (Dec. 31, 2008) (quoting Commission Letter Order to BGE, Item No. 10, June 18, 2008 Administrative Meeting, Mail Log No. 108061 (Aug. 18, 2008)).

And those supply-side benefits rely, in turn, on numerous assumptions and projections that are far from certain and that, to a large extent, are beyond the Companies' control. For example, Pepco and Delmarva each assumes that 75% of its residential customers will participate in, and respond to, CPR and CPP rates on a sustained basis over the life of the program. Whether this assumption proves accurate depends in part on whether the response of Pepco's and Delmarva's residential customers to dynamic pricing options is similar to that of BGE's pilot program participants, despite the many differences between that pilot and the Companies' Proposal. It depends on whether eligible commercial customers' response to dynamic pricing is at least as great as that of commercial customer participants in the California pilot on which Dr. Faruqui relies. And it depends on whether the Companies develop and effectively implement a customer education and communications program that will engage their customers at the level and for the duration necessary to render the Proposal cost-effective.

A second set of assumptions on which the projected levels of supply-side benefits rely is that: (1) the value of avoided energy and capacity costs will not deviate substantially from the estimates on which Dr. Faruqui based his projections; (2) customers will receive the full projected wholesale value of capacity and energy savings in the PJM markets, even though the Companies have not yet determined the manner in which they intend to monetize those savings; (3) reduction in electricity use during critical peak periods will depress wholesale market prices for energy and capacity to the extent and for the duration Dr. Faruqui predicts; and (4) PHI's SOS customers will receive the full benefit of those market price impacts. In addition, and as numerous Parties agree, the basis for the Companies' projected 1.5% energy conservation effect appears questionable at best, especially in the absence of in-home displays beyond the day-old consumption data the Companies plan to provide through "My Account."

Moreover, the Companies' projections are based upon their plans to make AMI-enabled dynamic pricing options available only to residential and small-to-medium commercial customers who purchase their electricity supply from Pepco and Delmarva through SOS. The record contains no evidence about the effect on the Companies' business cases of a continuation in the current trend toward customers choosing competitive electricity suppliers in lieu of SOS.[190] And as the Companies' own expert witness testified, Pepco's and Delmarva's small commercial customers are not expected to respond to dynamic pricing under the current Proposal,[191] raising questions about whether the Proposal will be cost-effective for *all* classes of PHI customers, even if it proves cost-effective on the whole.

Despite the uncertainties about projected supply-side benefits, however, it is important to recognize that the Companies expect operational savings to cover most of the cost of the Proposal: \$56.2 million (approximately 76%) of the projected \$73.7 million cost of the Delmarva project, and \$95.0 million (approximately 82%) of the projected \$115.6 million cost of the Pepco project (offset by matching DOE grant funds).[192] These savings in the Companies' distribution operations can be passed on to all classes of the Companies' Maryland customers in future rate cases. Likewise, all customers could potentially benefit, to at least some degree, from the energy and capacity

[190] See Public Service Commission of Maryland, Ten-Year Plan (2009-2018) of Electric Companies in Maryland at 76-78 (June 29, 2010).
[191] Faruqui Direct at 13.
[192] Potts Direct at 12-13.

price mitigation effects that PHI attributes to projected reductions in electricity use during critical peak periods in response to AMI-enabled dynamic pricing.

AMI deployment to all customers in the Companies' Maryland service territories has the potential to deliver other benefits as well – benefits less readily reduced to a mathematical cost-benefit ratio, but no less important to PHI customers. PHI anticipates that AMI will improve its outage detection and notification capabilities, for example,[193] and that it will reduce service restoration times.[194] Additional benefits the Companies expect to result from AMI-enabled dynamic pricing, and their projections about corresponding demand reduction, include: (1) improved reliability; (2) enhanced market competitiveness; (3) reduced rate volatility; (4) reduced transmission and distribution losses; (5) reduced need for investments in transmission and distribution; and (6) introduction of rates anticipated to "incent the appropriate use of new electric end-uses, such as plug-in vehicles and small scale renewable generators."[195]

Proceeding with AMI deployment in the Companies' Maryland service territory at this time also has advantages on the cost side of the cost-benefit equation. Maryland ratepayers have a window of opportunity to benefit from the economies of scale PHI negotiated with its vendors; from technological lessons learned from Delmarva's AMI deployment in Delaware; and, in the case of Pepco's ratepayers, from a $104.8 million Smart Grid Investment Grant award, $68.3 million of which will be used to partially offset the cost of AMI deployment, and the balance of which will help reduce the cost to

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[193] Potts Direct at 29, 33 (Exh. GWP-1).
[194] Tr. 26-27 (Gausman).
[195] Faruqui Direct at 24; *see also id.* at 25-27.

ratepayers of Pepco's Direct Load Control program, Distribution Automation project, and communications infrastructure project.

Although there are uncertainties inherent in the business cases advanced by both Companies, the federal grant award provides Pepco with a substantially wider margin for error in its projections than Delmarva has before AMI deployment would fail to deliver a cost-effective product for ratepayers. It is in large part for this reason that we authorize Pepco to proceed with AMI deployment in Maryland at this time, but defer granting such authorization to Delmarva pending our receipt and evaluation of a modified business case as set forth below. We ultimately will hold *each* Company accountable for delivering a cost-effective AMI system, however, before the associated costs will be incorporated into rates, and we intend to closely monitor the Companies' progress in that regard.

Accordingly, we hereby direct Pepco and Delmarva each to submit an updated and modified business case and associated benefits-to-costs analysis that demonstrate the cost-effectiveness of the Proposal. At a minimum, those business cases should:

(1) Be based upon a 10-year post-deployment project life rather than a 15-year post-deployment project life;

(2) Include the full estimated cost of a comprehensive customer education and communications program (including, but not limited to, costs associated with notifying customers of critical peak periods), which costs may not be subsumed under general "contingency" funds;[196]

[196] The Companies themselves identify "contingency" funds as intended "to help manage the current uncertainty around the AMI cost estimate" during the start-up and installation phase of the project. Proposal at 42. But little appears more certain than that comprehensive customer education and communications programs will be necessary to ensure the success and cost-effectiveness of this initiative. The Companies must separately account for the incremental costs associated with such programs in their business cases.

(3) Include the cost of in-home displays similar to those used in pilots or studies on which the Companies rely for their projections about customer response to dynamic pricing;

(4) Include the cost of ZigBee range extenders, to the extent the Companies reasonably anticipate that such extenders will be necessary to achieve signal transmission from customers' smart meters adequate to realize all projected benefits;

(5) Include a full analysis of all anticipated incremental costs and benefits associated with the Proposal, including but not limited to all incremental post-deployment O&M costs, to the extent that such costs have not already been addressed in the Companies' business cases;

(6) Omit projected O&M savings associated with remote disconnections for non-payment, to the extent that those projected savings are based on elimination of field visits by Company personnel prior to any such disconnection;

(7) Omit the Companies' projected 1.5% energy conservation effect; and

(8) Reflect modifications to the Companies' dynamic pricing proposal as set forth in section IV.B. below.

We also direct the Companies to submit a detailed plan regarding the manner in which they intend to monetize their projected AMI-enabled peak demand and energy savings in the PJM capacity and energy markets, and to fund the Critical Peak Rebates under the proposed Dynamic Pricing Rider.

B. Dynamic Pricing

The Companies propose three pricing options under a Dynamic Pricing Rider to their existing tariffs: a default CPR pricing structure, an opt-in CPP pricing structure, and opt-in flat SOS rates. We interpret the Companies' request for an order approving "the principle of dynamic pricing coupled with AMI" and directing the Companies "to go forward with that approach,"[197] as a request to approve these three pricing options, with specific rates under those options to be submitted at a later date. For the reasons discussed below, we approve, in principle, a limited version of the dynamic pricing structure proposed by PHI.

1. Critical Peak Rebates

The Companies propose that, following AMI installation, residential, small commercial, and medium commercial customers would default to the CPR pricing option. The CPR schedule would reflect the SOS rates then in effect, modified by a credit that would be provided to customers who reduce their electricity consumption from predetermined baseline levels during Company-declared critical peak periods. There would be no penalty imposed if a customer's usage during critical peak periods exceeded the customer's baseline.[198] The Companies have described CPR as a "no lose proposition" for customers, in the sense that "[t]he customer is no worse off" by not responding to critical peak periods than the customer would be on a flat SOS rate, but has an opportunity to lower his or her bill by earning a rebate for reducing consumption during those periods.[199]

For these reasons, Staff does not support retaining the SOS rate option, describing it as "functionally superfluous" and noting that CPR is designed so that "nonparticipants are not harmed, they simply forgo the opportunity to obtain a financial incentive."[200] AARP witness Alexander advocated a position similar in effect, in our view, to that of

[197] Tr. 931-32 (Bumgarner); PHI Initial Brief at 42-43.
[198] Bumgarner Direct at 5.
[199] *See* Tr. 215-16 (Faruqui); *see also* Bumgarner Reply at 6 (Under the CPR option, "the customer would be no worse off financially than under the SOS option, but would be able to receive information about high cost periods.").
[200] Staff Initial Brief at 14-15.

Staff: "I recommend that PHI continue its SOS rate as the default rate, but graft the CPR option onto that current rate so that all customers can participate without taking any further affirmative action."[201] In contrast, OPC argued that the CPR rate schedule should be offered "only as an opt-in rate after extensive customer education," reasoning that "it should be the customers' choice as to whether they want to engage with the bother of the potential to earn rebates via the CPR rate."[202]

We are persuaded by Staff's and AARP's arguments on this point. We find that presenting customers with a choice between an SOS rate schedule and a CPR rate schedule is redundant, potentially confusing, and unnecessary to protect those customers who either cannot or will not reduce their electricity consumption during critical peak periods. We therefore approve the concept of a dynamic rate schedule that will combine the SOS rates in effect at the time the schedule is implemented with the CPR opportunities available to residential, small commercial, and medium commercial customers once AMI has been installed. Although we emphatically agree with OPC that an extensive customer education program will be critical to ensure that PHI customers are in a position to make informed choices about CPR opportunities, it *will* be the customer's choice whether to engage in the potential to earn Critical Peak Rebates under the scenario we approve, and customers will not be penalized if they are unable or disinclined to do so.

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[201] Alexander Direct at 36.
[202] OPC Initial Brief at 56.

2. Critical Peak Pricing

We decline to approve at this time a CPP rate structure, even on an opt-in basis. We are persuaded that at this early stage of the Companies' AMI initiative, the risk is too great that customers will opt for CPP with the hope or expectation of lowering their bills, only to find that, at least initially, the CPP rate results in higher bills. In the words of PHI witness Faruqui, under a CPP pricing structure, some customers would be "instant winners" and others would be "instant losers." Although the Companies expect that "instant losers" would eventually offset their losses by responding to the higher price signal during critical peak periods, such an adjustment might not be feasible for certain of the Companies' most vulnerable residential customers, such as low-income households, elderly customers, customers with medical needs for electricity that cannot be shifted to off-peak hours, or other customers who, because of their personal circumstances, are less likely to be in a position to reduce peak load than the "average" residential customer.

Our concern in this regard is particularly acute because the Companies contemplate that once a customer has selected the CPP option – or either of the other two pricing options, for that matter – the customer would not be permitted to change his or her selection but once per year. Our concern is heightened further still by the Companies' lack of a detailed customer education and communications plan that would help ensure that customers make fully informed choices from the outset. Although a Critical Peak Pricing rate structure may be appropriate, or even desirable, at some point in the future, we believe that approval of such a structure is, at best, premature at this time.

3. Real-Time Pricing

MEA recommends that, in addition to CPP and CPR pricing structures, PHI should make available a real-time pricing option "for those customers who are willing and able to effectively manage their energy load during high demand periods."[203] PHI disagrees, contending that pilot programs conducted by Pepco and others demonstrate that residential and small commercial customers are not responsive to real-time pricing.[204]

For many of the same reasons that we decline to approve a CPP rate structure, we also decline to order PHI to provide a real-time pricing option to its customers at this time. Additionally, we note that the Proposal does not provide for real-time pricing signals to PHI customers, and that the record is devoid of evidence that any incremental energy or capacity savings attributable to real-time pricing would justify any additional expense necessary to make such a rate structure available. We agree with Staff that this is an option best analyzed after AMI has been deployed and customers are more accustomed to dynamic energy pricing.[205]

4. Critical Peak Event Standardization

AARP witness Alexander highlighted in her testimony the potential for substantial customer confusion that could result from the differences in PHI's and BGE's definitions of critical peak period seasons, times, and frequency.[206] Specifically, BGE's AMI Proposal contemplates up to 12 critical peak events per year, which would be in effect from 2 P.M. to 7 P.M. and would occur during the June 1 through September 30

[203] MEA Initial Brief at 23-25.
[204] Tr. 980-81 (Bumgarner).
[205] Tr. 1348 (Godfrey).
[206] Alexander Direct at 20; *see also* AARP Initial Brief at 26.

time period.[207] In contrast, PHI proposes up to 15 critical peak events which would be in effect for up to four hours from 2 P.M to 6 P.M. and would occur during the June 1 through Oct 31 time period. According to Ms. Alexander, "such differences are likely to prevent the use of a single [S]tate-wide media campaign about the need to lower electricity usage during certain hours each summer."[208] MEA witness Jennings expressed a similar concern, noting that the "overlap in TV, radio and media coverage" between Pepco's, Delmarva's, and BGE's Maryland service territories could contribute to customer confusion about whether their utility has declared a critical peak event, when it would start, and how long it would last.[209]

Staff recommended the establishment of a working group to address such "dynamic pricing implementation matters," and the Companies have expressed a willingness to participate in such a working group "to iron out inconsistencies across jurisdictions, as well as to iron out the final details of the pricing for the dynamic pricing and other implementation details."[210] We conclude that a collaborative effort to establish uniformity of critical peak period seasons, times, frequency, and duration, and other aspects of dynamic pricing implementation, to the extent feasible, is appropriate and in the public interest. We therefore direct Staff to commence such a working group to include, at a minimum, representatives from BGE, Pepco, Delmarva (if and when we approve AMI deployment in Delmarva's Maryland service territory), Staff, and OPC.

[207] *See* Case No. 9208, Order No. 83410 at 20 (June 21, 2010); Case No. 9208, Dkt. No. 47, BGE Initial Brief at 7.
[208] Alexander Direct at 20.
[209] Tr. 655-56.
[210] Tr. 931-32 (Bumgarner).

All other Parties to this Case and to Case No. 9208 also shall be invited and encouraged to participate.

C. Cost Recovery

We hereby approve Pepco's request to establish a regulatory asset for incremental costs associated with AMI deployment, including but not limited to deferred "start up" costs, in an AMI regulatory asset, to be offset by known and quantifiable AMI-related cost savings.[211] The unamortized balance in this regulatory asset shall accrue at the Company's authorized rate of return. Depreciation expense recorded in Pepco's regulatory asset for incremental AMI costs will be further reduced by the depreciation expense embedded in current rates related to the existing meters.[212] In the event we determine that Delmarva's modified business case is sufficiently robust to permit us to authorize AMI deployment in Delmarva's Maryland service territory, we shall authorize Delmarva to establish a similar regulatory asset.

We find that regulatory asset treatment of AMI deployment costs will appropriately synchronize the timing of customer costs and benefits, thereby providing an opportunity for ongoing review of the Proposal's cost-effectiveness in future rate cases. In authorizing Pepco to establish this regulatory asset, we recognize that Pepco should have the opportunity to recover prudently incurred costs associated with the Proposal, as well as to earn an appropriate return. As PHI properly acknowledges, however, our authorization of a regulatory asset is not an advance determination that all costs associated with the Proposal were prudently incurred. Rather, it provides the Company

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[211] PHI Initial Brief at 48.
[212] *Id.* at 50-51.

"the opportunity to recovery prudently incurred costs associated with the deployment of AMI," while also preserving the Parties' ability to challenge – and our ability to determine – the prudency of those costs "when the Company seeks to recover them" in the context of a future base rate case.[213] The Commission's determinations in that regard will be informed by whether the Companies have, in fact, delivered a cost-effective AMI system, the individual and collective benefits of which are worth the ratepayers' investment. The Companies will have the burden to make that showing with respect to all costs booked to the regulatory asset (including, but not limited to, deferred "start-up" costs). In the event that the Proposal, as implemented, falls short of that standard, we will determine in a base rate case what level of cost recovery the public interest requires.

With regard to the undepreciated book value of the Company's existing meters, as we stated in our recent Order granting BGE's request to proceed with its AMI Initiative, "we cannot prejudge the precise cost recovery for [the Company's] legacy meters at this time."[214] Rather, the complicated issues relating to legacy meter recovery are appropriately considered in a depreciation proceeding, with the benefit of a depreciation study and a proper factual record, including actual removal, disposal and salvage of the legacy meters.

D. Required Customer Education Plan and Budget, Metrics, and Periodic Review

The cost-effectiveness of PHI's Proposal hinges on the Companies' ability to deliver at least some measure of the supply-side benefits they have promised. And the Companies' ability to achieve that result is highly dependent upon bringing about a

[213] Wathen Direct at 4.
[214] Case No. 9208, Order No. 83531 at 41.

fundamental change in their customers' behavior. Yet PHI has not yet developed a plan for the type of detailed, comprehensive customer education and communications program that the Parties agree will be necessary to effectuate and sustain such change, nor do the Companies appear to have fully considered the costs of such a program. That cannot continue if either Company is to move forward with AMI deployment in this State.

Therefore, consistent with our Order of August 13, 2010, we direct Pepco, in consultation with the other Parties, to develop and submit for our approval a detailed and comprehensive customer education and communications plan, which we expect Pepco to implement sufficiently *in advance* of AMI deployment in Maryland to optimize customer awareness and engagement. We further direct Pepco, in consultation with the other Parties, to develop and submit for our approval: (1) a corresponding customer education and communications budget; and (2) a comprehensive set of metrics for all aspects of the Proposal, including but not limited to: (a) installation and performance of the technology; (b) incremental costs incurred; (c) incremental benefits realized; (d) effectiveness of customer education and communications efforts, to include, among other things, customer satisfaction and participation levels; and (e) customer privacy and cybersecurity. We will expect a similar plan and similar metrics from Delmarva in the event that we ultimately approve AMI deployment in its Maryland service territory, after Delmarva submits an updated and modified business case as described in this Order. We will require the Companies to report to us their respective performance against the metrics we approve, and to appear for periodic review hearings in which we will monitor each Company's progress toward achieving the goals set forth in their Proposal.

VI. Conclusion

The decisions reflected in this Order strike an appropriate balance between providing the Companies and their Maryland customers the opportunity to realize the many potential benefits AMI has to offer, on the one hand, and protecting Maryland ratepayers from the very real possibility that the Companies' projections about AMI-related costs and benefits will prove overly optimistic, on the other. We are persuaded that in Pepco's case, the award of a Smart Grid Investment Grant makes it more likely that the value of AMI-enabled benefits will exceed the cost of the Proposal (as modified herein) to the Company's ratepayers, and will provide a real return on ratepayers' investment. In Delmarva's case, we are not prepared to draw that conclusion on the record before us. We therefore decline to approve AMI deployment in Delmarva's service territory at this time, but we look forward to evaluating the updated and modified business case that we direct the Company to submit.

Providing Pepco the opportunity to recover its prudently incurred incremental costs in a future base rate case, through a properly structured regulatory asset, mitigates and appropriately allocates between Pepco and its customers the risks inherent in this venture. The Company will bear the burden of demonstrating in such a base rate case that it has incurred a level of costs and delivered a level of benefits such that its AMI project is a worthwhile and cost-effective investment for its Maryland customers, and the metrics and periodic review hearings described in this Order will allow us to monitor the Companies' progress toward that end. We reiterate that to meet its burden, it will be imperative that Pepco (and Delmarva, if we ultimately approve AMI deployment in that Company's service territory) develop, launch and sustain a comprehensive customer education and communications program that will engage its customers in achieving the full range of AMI-enabled benefits on which PHI's Proposal relies.

IT IS THEREFORE, this 2nd day of September, in the Year Two Thousand Ten, by the Public Service Commission of Maryland,

ORDERED: (1) That Potomac Electric Power Company is authorized to proceed with deployment of its AMI proposal, as conditioned by this Order, and shall submit an amended business case and associated benefits-to-costs analysis that demonstrate the cost-effectiveness of the Proposal, for the Commission's review, consistent with the terms of this Order;

(2) That a decision on Delmarva Power & Light Company's request to proceed with deployment of its AMI proposal is deferred, and Delmarva is directed to submit an amended business case and associated benefits-to-costs analysis that demonstrate the cost-effectiveness of the Proposal, for further Commission consideration, consistent with the terms of this Order;

(3) That both Companies shall submit a plan detailing how each intends to fund their proposed Critical Peak Rebate dynamic pricing structure, including the manner in which they intend to monetize peak demand and energy use reductions attributable to AMI, consistent with the terms of this Order (subject to subsequent authorization to Delmarva to deploy AMI in Maryland);

(4) That Pepco develop with the other Parties to this matter, and submit for the Commission's approval, a detailed and comprehensive customer education and communications plan, consistent with the terms of this Order, along with a corresponding customer education and communications budget. Pepco shall implement

any approved customers education and communications plan well in advance of AMI deployment in Maryland;

(5) That Pepco and the other Parties in the matter shall develop, and submit for the Commission's approval, a comprehensive set of metrics for all aspects of the Company's AMI proposal, including but not limited to: (a) installation and performance of the technology; (b) incremental costs incurred; (c) incremental benefits realized; (d) effectiveness of customer education and communications efforts, to include, among other thing customer satisfaction and participating levels; and (e) customer privacy and cybersecurity that will allow the Commission to assess the progress and performance of each Company's AMI deployment, along with a format for reporting such metrics to the Commission on a periodic schedule, to be determined at a later time;

(6) That Potomac Electric Power Company is authorized to establish a regulatory asset for the incremental costs associated with the AMI deployment, including start-up costs, consistent with the terms of this Order, and at the time that the Company has delivered a cost-effective AMI system, the Company may seek cost recovery in a base rate proceeding;

(7) That Delmarva Power & Light Company's request to establish a regulatory asset for the incremental costs associated with its proposed AMI deployment is not granted at this time, pending submission of its revised business case and authorization by the Commission to deploy its proposed AMI system;

(8) That cost recovery for the legacy meters that Potomac Electric Power Company will remove to replace with "smart" meters shall be considered in a future depreciation proceeding;

(9) That neither Company is authorized to implement a Critical Peak Pricing rate structure at this time. The concept of a dynamic rate schedule that combines the Standard Offer Service rates in effect at the time the schedule is implemented with the Critical Peak Rebate opportunities for residential, small commercial and medium commercial customers once AMI has been installed is approved (subject to subsequent authorization to Delmarva to deploy AMI in Maryland);

(10) That Staff is directed to convene a working group to include, at a minimum, representatives from Baltimore Gas and Electric Company, Potomac Electric Power Company, Delmarva Power & Light Company (subject to subsequent authorization to Delmarva to deploy AMI in Maryland), and the Office of People's Counsel to develop, and submit for the Commission's consideration, a proposal for uniformity of critical peak period seasons, times, frequency, and duration, and other aspects of dynamic pricing implementation, to the extent feasible. All parties in this matter and Case No. 9208 are invited to participate, as are other interested stakeholders; and

(11) That all other motions or requests not granted herein are denied.

/s/ Douglas R.M. Nazarian

/s/ Harold D. Williams

/s/ Susanne Brogan

/s/ Lawrence Brenner

/s/ Therese M. Goldsmith

Commissioners