May 22, 2009

Ms. Dorothy Wideman  
Commission Secretary  
Public Service Commission  
of the District of Columbia  
1333 H Street, N.W.  
2nd Floor West Tower  
Washington, D.C. 20005

Re: Formal Case No. 1056

Dear Ms. Wideman:

Enclosed please find for filing are the original and fifteen (15) copies of the Direct Testimony and Exhibits of Company Witnesses Gausman, Potts, Faruqui and Kamerick.

Please contact me if you have any questions regarding this matter.

Sincerely,

Deborah M. Royster

DMR/sar

cc: Elizabeth A. Noel, Esq.
BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF

The Application of 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

Formal Case No. 1056

Volume I of 1: Direct Testimony and Exhibits
Of Company Witnesses GAUSMAN, POTTS,
FARUQUI and KAMERICK

May 22, 2009
WILLIAM M. GAUSMAN
Direct Testimony
D.C. P.S.C. - May, 2009

Introduced as:
PEPCO (A)
Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is William M. Gausman. I am the Senior Vice President, Asset Management and Planning for Pepco Holdings, Inc., located at 701 Ninth Street NW, Washington, DC, 20068.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR ROLE AS SENIOR VICE PRESIDENT ASSET MANAGEMENT AND PLANNING?

A. I am responsible for the engineering, design and planning for all transmission, substation and distribution facilities constructed by Pepco Holdings, Inc. subsidiaries, which include Potomac Electric Power Company (Pepco), Delmarva Power & Light Company (Delmarva), and Atlantic City Electric Company (ACE). In addition, I am responsible for all reliability planning and system performance evaluation as well as development and monitoring of the construction program and operating budget. I also am responsible for the oversight of the utilities involvement with PJM, the regional transmission grid operator, and Smart Grid, including Advance Metering Infrastructure (AMI).
Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a B.S. degree in Electrical Engineering Technology from Temple University in 1974 and joined Pepco as a Project Engineer overseeing the construction of high voltage transmission facilities. I have served in various management positions with increasing responsibility for the operation, maintenance and construction of both transmission and distribution systems. From 1977 until 1988, I served as Superintendent of Underground Lines. From 1988 until 1998, I served as Manager of Electric System Operation and Construction. In 1998, I was promoted to General Manager Power Delivery, and in 2001 was made General Manager-Asset Management. In August 2002, I was promoted to Vice President-Asset Management, Pepco. After Pepco’s merger with Conectiv, I accepted the position of Vice President-Asset Management with responsibility over the combined power delivery organization. In March 2008, I was elected Senior Vice President-Asset Management and Planning.

During my career with Pepco, I have served as an advisor to various industry organizations including the Electric Power Research Institute Distribution Committee, the Southeastern Electric Exchange Executive Committee and

2
the Edison Electric Institute Distribution Committee. I am
currently a member of the AEIC Electric Power Apparatus
Committee and EEI Transmission Executive Advisory
Committee. Also, I am a member of Leadership Greater
Washington.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY
AUTHORITIES?
A. I have testified before various state regulatory
agencies in the District of Columbia, Maryland, Delaware
and New Jersey, as well as before the Federal Energy
Regulatory Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
A. The purpose of my testimony, and that of the
witnesses which I will introduce, is to provide
information as requested by the Commission in its Order
No. 15252 in Formal Case No. 1056 concerning Advanced
Metering Infrastructure and the Company’s motion for
expedited consideration of its proposed implementation of
an advanced metering infrastructure serving the District
of Columbia.

This testimony was prepared by me or under my direct
supervision and control. The source documents for my
testimony are Company records, public documents, and my
personal knowledge and experience.
THE COMMISSION’S REQUESTED INFORMATION

Q. WHAT SPECIFIC ISSUES DID THE COMMISSION IDENTIFY IN ITS ORDER?

A. The commission identified the following three areas that Pepco will support within its Direct Testimony in this case:

- The cost of the project (both with and without American Recovery and Reinvestment Act of 2009 (ARRA) funding).
- The benefits of the project (including a current cost/benefit analysis).
- The details of how the proposed cost recovery mechanism (the regulatory asset) will work.

Q. WHAT FURTHER SUPPORT FOR PEPCO’S MOTION WILL YOU PROVIDE TO THE COMMISSION?

A. In responding to the Commission’s identified issues I will provide information that supports the fact that Pepco’s AMI proposal is mature and ready now for deployment in Washington D.C. I will provide a summary that demonstrates Pepco’s accomplishments in AMI and the fact that our cost estimates as presented in the 2007 filing of the Blueprint Business Case for AMI remain accurate after having made the majority of technology and
I will provide an overview of what Pepco envisions as a smart distribution grid (Smart Grid). I will also describe our planned installation of the AMI system and discuss the benefits to our customers, once this technology is installed and how the installation of these systems may be eligible for stimulus funding from DOE.

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S FILING?

A. This filing consists of my testimony and that of three other witnesses. As described more fully below, those witnesses, and the topics they address, are as follows:

- Mr. George Potts - Technical witness, AMI/Smart Grid including the PHI business case, project costs, operational benefits, selected technology and vendors.

- Dr. Ahmad Faruqui - Customer benefits of AMI, peak and base demand reductions in energy consumption.

- Mr. Anthony Kamerick - Description of the Company's proposed cost recovery mechanism and the financial implications of cost recovery in today's economic climate.
Q. PLEASE SUMMARIZE PEPCO’S ACCOMPLISHMENTS TO DATE THAT SUPPORT YOUR ABILITY TO MOVE FORWARD IMMEDIATELY WITH THE AMI PROJECT IN WASHINGTON D.C.

A. Pepco has in place contracts for the furnishing of the major systems, materials and services to support AMI. These items, the status of which is summarized in the table below, include the automated meters, the Meter Data Management System (MDMS), the communications system, the meter installation contract and the AMI systems integration contractor.

<table>
<thead>
<tr>
<th>Area of Work</th>
<th>Selected Vendor</th>
<th>Contract Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMI Meters</td>
<td>General Electric (GE) and Landis + Gyr (L+G)</td>
<td>Contract Signed</td>
</tr>
<tr>
<td>Communications System and Meter Network Interface Card</td>
<td>Silver Spring Networks (SSN)</td>
<td>Contract Signed</td>
</tr>
<tr>
<td>Meter Data management System</td>
<td>Itron</td>
<td>Contract Signed</td>
</tr>
<tr>
<td>AMI Meter Installation</td>
<td>Scope Services</td>
<td>Contract Signed</td>
</tr>
<tr>
<td>AMI Systems Integration</td>
<td>IBM</td>
<td>Contract Signed</td>
</tr>
</tbody>
</table>

Q. PLEASE SUMMARIZE HOW THESE ACCOMPLISHMENTS HAVE AFFECTED YOUR CAPITAL COST FORECAST FOR THE AMI INSTALLATION IN THE DISTRICT.

A. After nearly two years and many accomplishments I find no need to adjust our original cost estimate for the
deployment of AMI in the District. This estimate is $61.3 million. Our current capital cost forecast is tracking about $2.8 million below our original estimate.

Capital Cost: Project Estimate and Current Forecast

<table>
<thead>
<tr>
<th>AMI System Components</th>
<th>Project Estimate Original Business Case</th>
<th>Current Forecast May 2009</th>
<th>Notes:</th>
</tr>
</thead>
<tbody>
<tr>
<td>AMI Meters Including Installation Costs</td>
<td>$35,760</td>
<td>$49,120</td>
<td>The Meter Network Interface Cards were included in the Communications Network costs in the original estimate and have been purchased as part of the AMI meters contract.</td>
</tr>
<tr>
<td>Communications Network including Installation Cost</td>
<td>$18,304</td>
<td>$1,936</td>
<td>(See Above)</td>
</tr>
<tr>
<td>AMI Network Management System and Meter Data Management System</td>
<td>$3,740</td>
<td>$3,973</td>
<td>The Pepco allocated share of the overall PCC costs for these common systems.</td>
</tr>
<tr>
<td>Subtotal</td>
<td>$57,820</td>
<td>$55,029</td>
<td>Decrease of $2.8 million Estimate vs. Current Forecast</td>
</tr>
<tr>
<td>Contingency</td>
<td>$3,468</td>
<td>$6,243</td>
<td>The contingency allocation has not been reevaluated and is stated here as the sum of the original contingency plus the cost decreases identified in the current forecast</td>
</tr>
<tr>
<td>Totals</td>
<td>$61,272</td>
<td>$61,272</td>
<td></td>
</tr>
</tbody>
</table>
Q. WHAT IS SMART GRID?

A. The Smart Grid represents perhaps the greatest technological transformation for electric utilities since the nation’s electric grid was first created. A Smart Grid is an electricity network, or grid, that has evolved from its historical components to become "smart", or able to utilize today’s state-of-the-art technology and communication innovations. By "smart," we mean that the grid has two-way communication between home meters and the utility; advanced sensors throughout the grid to allow improved reliability and the ability to reconfigure itself, efficiently and with security; an overall expansion in information flowing both to customers and the utility; an advanced analytical platform for better situational awareness; and ultimately the ability to build on all of these capabilities to provide improvements to the distribution network.

A Smart Grid requires a more sophisticated metering and communications infrastructure known as Advanced Metering Infrastructure (AMI). The AMI meter collects and communicates transactional data at the point of delivery to the customer. For this reason, AMI forms the foundational knowledge base for the Smart Grid. The Smart Grid also requires sensors throughout the distribution
grid, including a number of devices such as smart relays, automatic circuit reclosers (ACRs), switches, and a number of other intelligent devices. Information continuously reported by these devices is brought together in intelligent controllers that automatically detect faults on the distribution circuits and issue commands to switching devices on those circuits to isolate faulted areas and re-route power to restore service to customers not directly supplied from the faulted area. These advanced control schemes, referred to as Automatic Sectionalizing and Restoration (ASR) schemes, dramatically reduce the time required to identify and isolate faulted locations and restore service to those customers not directly supplied from the faulted area. The Smart Grid consists of three main levels: the substation level, feeder level and customer level. A diagram below shows sample devices and mechanisms at each of these levels.
Q. WHAT IS PEPCO’S VISION OF SMART GRID?

A. Through the Smart Grid, customers will become empowered to make informed choices regarding their use and cost of energy. The Smart Grid facilitates innovative ways to take advantage of energy alternatives and efficiencies regarding both the delivery and consumption of energy. For example, new rate designs could be enabled through the collection of additional hourly consumption data collected through the AMI system. This information would also be provided to customers through an internet website to allow customers to increase their understanding of energy use over the course of the day. Intelligent grid sensors and components are added to the network to improve control, quality, reliability and security. The integration of network communications, use of automated controls and application of data intelligence supports the planning and design process for improving energy flow on the grid. During certain emergency situations, the electric system may be able to restore customers automatically and will report outage events with far greater accuracy and speed than today.

Q. WHAT IS PEPCO’S STRATEGY FOR SMART GRID?

A. Pepco began steps to deploy Smart Grid several years ago by installing automation devices at new substations.
Witness Gausman

This was an evolution of electro-mechanical devices to microprocessor-based equipment. Our strategy has been to replace and improve the delivery infrastructure as new construction and replacement decisions are made. Our existing strategy is to install this equipment throughout the service territory and when fully integrated, Pepco will have the ability to manage and operate the devices as a total system rather than as a series of independent devices. Thus, the Smart Grid will modernize our delivery infrastructure over time. Our multi-year plan uses state of the art systems and technologies, new pricing options and energy efficiency programs to reduce energy costs and volatility. Improved reliability and customer service, and protection of our natural resources, are all drivers for our strategy, with the final goal to improve overall customer satisfaction.

A complimentary rate decoupling design that aligns customer and the company to promote a smart grid is needed so that the performance of the company is not jeopardized by our success in reducing customer usage and costs.
Q. WHAT ARE THE STEPS THAT ARE NEEDED TO BE ACHIEVED FOR THE COMPANY TO IMPLEMENT A SMART GRID?

A. The evolution towards achieving Smart Grid includes five steps that are the building blocks to a mature Smart Grid:

**Deployment of smart sensors and controls into the grid** - the first building block is the layer containing smart devices in the field. The largest investment of this sub-component is the deployment of AMI meters and related communications infrastructure into the field;

**Rollout of robust communications infrastructure** - another building block is an expansion of communication networks. The Smart Grid will require communication networks capable of transmitting at a high throughput the vast amounts of data the smart devices in the field will be producing;

**Integration of corporate IT systems** - Another step involves integrating corporate IT systems so they can rapidly process all of the new data being generated throughout the grid;

**Development of new data analysis capabilities** - data analysis capabilities will evolve and expand to
process the influx of new data being sent from the Smart Grid;

*Capability of real-time optimization of the distribution network* - this last step represents the final evolution of the Smart Grid, namely the ability to optimize in real-time its performance.

Q. WHAT ARE THE DRIVERS THAT CAUSE PEPCO TO SUPPORT THE DEVELOPMENT OF A SMART GRID?

A. Now that the network communication technology has advanced to enable automation and integration of system devices, it is feasible to carry out transformational changes in the utility industry. This change is further driven by a number of factors that have converged to necessitate the implementation of Smart Grid technology. The drivers can be broken into two broad categories.

Macro-drivers include:

*Supply/demand imbalances, volatile energy and natural resource prices* - The past several years have seen costs for energy rising much faster than inflation. This has created a push for more energy efficient technologies, alternative and renewable energy sources and other solutions that will help to reduce the burden of rising prices. There are also capacity constraints in terms of demand exceeding
supply. This requires new and innovative ways to meet the growing demand;

**Pressures on the environment** - As evidence mounts as to the need to reduce the use of our natural resources, it is becoming more and more imperative that all stakeholders do their part to conserve these resources and reduce associated emissions. The Smart Grid concept helps to relieve some of the pressures on the environment by helping to improve efficiency, reduce electricity losses and enable higher penetration levels of renewable sources of energy;

**Federal legislation supporting Smart Grid technology** - The Energy Independence & Security Act of 2007 (EISA) encourages the development of Smart Grid technology and will create mechanisms to track progress. This legislation was also fueled by concerns over security and aging infrastructure;

**State legislation mandating renewable portfolio standards (RPS)** - Numerous states as well as the District of Columbia are mandating that a certain percentage of electricity generation comes from renewable resources. The Smart Grid will enable the development of these sources of renewable energy;
Micro-drivers include:

*Opportunity for reliability improvements* - Pepco is always seeking ways to improve upon its record of reliability and the Smart Grid will provide additional information, intelligence, analysis, and automatic control to achieve further significant improvements;

*Customer desire for choices* - Customers want convenient options to automatically manage their energy usage based on pricing signals and to protect the environment. They also want to take more advantage of smaller, on-site renewable energy sources.

*Customer desire for more information on energy use* - As public awareness grows regarding energy challenges the nation is facing, customers are increasingly demanding robust information on the amount of energy they use;

*Customer desire to reduce energy needs* - With increasing energy cost and customer desire to reduce total energy usage, improved information on energy usage provides the information that they need to make decisions on how they want to use energy to achieve energy reduction goals.
Q. HAVE THE TECHNOLOGIES AND CONCEPTS APPLIED TO SMART GRID BEEN TESTED AND PROVEN TO BE EFFECTIVE?

A. Yes. The core technologies and concepts used to implement a Smart Grid have existed for a number of years and have been used in a tactical fashion to gain isolated benefits or address specific issues. The Smart Grid builds upon those technologies and concepts, expanding and integrating the various tactical solutions into a fully interconnected, integrated deliberate strategy for providing electric service to our customers. The fully interconnected, integrated nature of a Smart Grid provides additional benefits that cannot be realized from isolated, tactical solutions.

Q. HOW DOES SMART GRID ALIGN WITH THE GOALS OF THE DISTRICT OF COLUMBIA TO REDUCE ENERGY USAGE?

A. Full implementation of Smart Grid will enable Pepco to support the District of Columbia’s efforts to reduce energy use. Modernizing the electric grid with smart technologies will facilitate the achievement of goals such as energy conservation, energy efficiency, peak demand reduction, and renewable energy initiatives. Working together, these innovative technologies will help customers and Pepco more effectively manage energy use, reduce energy bills, and reduce greenhouse emissions. In
addition, these advances will provide more opportunities for integration of distributed renewable energy sources into the electric system, enhance customer programs and services, and improve reliability.

Q. HOW DOES SMART GRID ALIGN WITH THE FEDERAL ENERGY POLICY?

A. Implementation of Smart Grid directly aligns with Federal energy policies and objectives. The Federal Energy Policy Act of 2005\(^1\) promotes investment in "technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs", and to "enable the electric consumer to manage energy use and cost through advanced metering and communications technology." In addition, the Energy Independence and Security Act of 2007\(^2\) states that "It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

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- Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
- Dynamic optimization of grid operations and resources, with full cyber-security.
- Deployment and integration of distributed resources and generation, including renewable resources.
- Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
- Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and Distribution Automation.
- Integration of "smart" appliances and consumer devices.
- Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
- Provision to consumers of timely information and control options.
- Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
- Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services."

Q. **WHAT ARE THE CAPABILITIES AND BENEFITS OF SMART GRID?**

A. Smart Grid automatically accommodates changing conditions in the electric system. Faults can be isolated and most customers that are not directly connected to the section of the line that has faulted can be restored automatically. Voltage profiles can be improved and load patterns modified through rerouting power flows. Automated notification of corrective actions and maintenance activities minimizes the workforce intervention required. Smart Grid allows the utility to design and operate assets with greater efficiency, reliability, security and safety. Customers will have more information, including program and pricing options, to make informed energy choices about their service and use. Smart Grid accommodates new end uses, promotes green
initiatives and enables distributed renewable energy
sources.

The Smart Grid's integrated technology provides a
number of benefits, including:

Sent ahefsrnxerir service - With the Smart Grid,
customer service representatives will have access to
a vastly superior base of information regarding each
customer. As a result, they will be able to educate
and offer advice to customers regarding various
programs, products and practical tips for saving
energy;

Improved customer choice - Customers will have the
option of selecting from a number of rate
structures, flexibility regarding receiving and
paying bills, choice regarding the generation mix of
their energy supply and a host of other options to
better manage their energy costs and usage,

Base load usage reduction and peak load reduction
and subsequent lower bills - Customers will benefit
from overall reduced usage of power due to energy
efficiency programs. In addition, the Smart Grid
will allow for a reduction in peak demand - through
demand response programs, critical peak pricing, etc. - that will also lower customers’ bills;

*Wider penetration and future adaptability of small distributed generation and energy storage (PV, PHEV, V2G)* - The Smart Grid will be adaptable to include the incorporation of various forms of distributed generation in the future - generation near the point of consumption - including photovoltaics (PV), vehicle-to-grid (V2G) and other forms of local generation and storage;

*Bi-Directional metering* - With the rollout of distributed generation, such as photovoltaics at customer premises, residential and commercial customers will have the capability of monitoring and accounting for energy both consumed and produced. This, combined with innovative rate structures will facilitate a transactional relationship between the customer and the utility;

*Improved reliability* - The Smart Grid will improve customer reliability in a variety of ways, including active response to changing conditions and automatic sectionalizing and restoration of faulted circuits. The Smart Grid will also provide enhanced
situational awareness which will allow crews to be more quickly dispatched to exact trouble locations;

**Outage detection and restoration notification** - The presence of smart sensors throughout the grid will provide Pepco with greater capability to detect outages. At the same time, it will improve notifications regarding the restoration of service to customers. Pepco will be able to know when customers are without power so they will have less need to call the utility to report outages. Similarly, Pepco plans to develop the capability to proactively notify customers when they are expected to be restored and remotely verify power is restored;

**Remote monitoring and control of appliances** - By harnessing intelligence in the Smart Grid, customers will have the ability to remotely monitor and control their home appliances. For example, a homeowner may decide to remotely turn-off the air conditioner in order to save energy and reduce the utility bill;

**Environmental Benefits**

**More efficient delivery of energy** - The Smart Grid, combined with network analytic capabilities and
future optimization will allow Pepco to operate its grids in a more efficient manner, thus saving electricity in the delivery transaction;

Reduction in the use of natural resources - By reducing demand both in peak times and overall, through energy efficiency, the Smart Grid will enable customers and the utility to reduce their use of natural resources;

Renewable energy and distributed generation and storage options - The Smart Grid’s adaptability and optimization capability will facilitate a wider penetration of small distributed generation sources, including photovoltaic’s and vehicle-to-grid (V2G) and energy storage options.

Improved energy security - reduction in usage leads to less dependence on energy imports and brings the nation a step closer to energy independence.

Utility Operational Benefits

Improved relationship with the customer - Through Smart Grid, Pepco envisions the relationship with the customer evolving to the point where the utility becomes an energy advisor rather than just a provider. Additional capabilities will allow customers to have more flexibility in terms of
managing their needs and their relationship with the utility. Pepco believes this will lead to improved customer satisfaction;

*Operational efficiencies* - With the implementation of Smart Grid, Pepco will be able to achieve various operational efficiencies through the deployment of new technology. In addition to technology improvements and enhanced data and communications, Smart Grid will also allow Pepco to improve many of its business processes. For example, increased billing accuracy will reduce the amount of rework required with inaccurate bills;

* Longer asset life * - The Smart Grid and its improved analytical capabilities will allow Pepco to operate its assets to peak capability and know when equipment is operating over its maximum rating, (which reduces the life of the equipment). In addition, Pepco will have better insight into the performance of assets and be better able to respond to potential problems before they arise;

*Supports a competitive supply environment* - As more customer-specific energy use information becomes available, this will support more competitive pricing among suppliers.
Improved system reliability - The smart grid will change the way that the electric system is operated by installing the technologies that allows devices to operate, based on analysis of data from field sensors, without any human intervention. In this way customers will be restored faster after an outage, the company will have better data as to the actual condition of the electric system and customers will no longer have to call in to report an outage for the company to know the state of their electric service. Pepco will be able to identify individual pieces of equipment that may be overload and take corrective action to resolve the overload before the equipment fails, thereby eliminating an outage to the customer.

Q. WHAT ARE THE COMPONENTS OF THE PEPCO SMART GRID?

A. Smart Grid is built on the foundation of the following primary areas:

Advanced Metering Infrastructure - AMI is the backbone of Smart Grid. AMI includes intelligent end devices which enable bi-directional information exchange between Pepco and its customers. AMI technology is critical to the overall operations and performance of Smart Grid. AMI meters provide essential hourly usage data to be
collected to support new customer offerings, provide a view of power quality at the point of delivery, improve tamper and theft detection and enhance customer service. AMI will enable Pepco to provide better response and restoration for outage management and optimization of utility assets to provide both proactive and predictive system design and planning. The system could also have the ability to communicate directly with customers' thermostats and appliances and control their operation based on power prices, if so desired by the customer.

**Communications Infrastructure** - Pepco plans to install an enterprise-wide communications infrastructure to accommodate existing communication needs as well as the future demands of the Smart Grid. In addition, AMI-related communication upgrades were also filed under the Blueprint plan and are compatible with achieving the Smart Grid. This more robust communications infrastructure will be necessary to reliably handle the increased data flowing to and from the customers and from distribution system equipment and devices. In addition, it will allow for the operation and control of the electric system in order to obtain the desired reliability improvements. This communication system must be designed not only to transmit data during times of
wide spread system outages, but must also be secure so as to prevent the intrusion of third parties that may attempt to take over the control or operation of the electric system.

The figure below summarizes the proposed communications architecture. As shown, the architecture will comprise four main elements:

- A home area network utilizing ZigBee protocol;
- An underlying wireless mesh network for communicating with customers, communicating with field devices and collecting AMI data;
- A wireless backhaul to bring the field data back to a substation or other field collection point, and;
- Fiber optics for high speed data transmission between the substations and Central Operations Centers.
Energy Efficiency Programs - As proposed in our Blueprint filing, Pepco proposes to manage a suite of energy efficiency programs benefiting most customer segments and having significant environment benefits.

Direct Load Control programs - With full implementation of the Smart Grid, Pepco proposes to manage a suite of new Direct Load Control Programs benefiting most customer segments and having significant environmental benefits. In addition, advanced Direct Load Control programs will include a rate incentive that is designed to proactively change customer behavior over time.

Advanced Direct Load Control/Smart Thermostat or Switch - This program is meant to provide a simple method for residential customers with
central air conditioning or heat pump systems to automatically reduce peak electricity demand during peak usage periods and to reduce their overall electricity consumption. This will be accomplished through the installation of remotely controllable smart thermostats (or switches) capable of reducing the air conditioner’s load on the electric system when a command signal is received from the utility. An added benefit is it allows the customer to program varying temperature settings by time of day and day or week;

**Dynamic Pricing Mechanisms** - This program will offer customers financial incentives for reducing their electricity usage during a critical peak event.

These programs aim to reduce load at peak times in order to better balance supply and demand and prevent price spikes.

**Improved Integration of Renewable Energy Sources**

Renewable energy sources include wind, solar, energy storage, plug-in hybrid vehicles, and vehicles-to-grid technologies that are often connected to distribution circuits at a customer’s location, creating sources of
energy distributed throughout the distribution circuits. Smart Grid provides the intelligent monitoring and controls necessary to reliably operate distribution circuits at higher penetration levels of distributed generation than would otherwise be possible. Since distribution circuits were traditionally designed to provide one-way power flow (delivering energy to the customer), significant penetration levels of distributed generation (customers delivering energy to the utility) could possibly lead to degraded distribution circuit performance without the enhanced intelligence and controls provided by a Smart Grid.

**Distribution Automation**

Distribution Automation (DA) is a collection of advanced power technologies designed to improve the efficiency of energy delivery and to reduce the frequency and duration of electric system outages. There are a number of devices and technologies that serve as components of DA. These devices and technologies work together to automatically isolate any problem areas on the network and reconfigure the network to minimize the impact to customers. Pepco is already deploying DA solutions for the purposes of system protection and reliability improvement, and installs these systems as
part of new system expansion projects. Since DA is part of our core business, the DA plans were not submitted with the Blueprint regulatory filing. However, DA is an integral part of the Smart Grid, along with AMI. DA components which support Smart Grid may include:

**Substation Local Area Network (SLAN)** - Some of the devices the SLAN will network together are Intelligent Electrical Devices (IEDs), such as protective relays; Remote Terminal Units (RTUs); Human Machine Interfaces (HMIs); smart sensors & controllers; wireless gateways and physical security systems such as video surveillance and intrusion detection equipment. SLANs will allow broader sharing of information, advanced autonomous restoration applications to efficiently restore customer service, and a wide variety of other applications. The wide sharing of information SLANs will enable will also allow centralized applications to optimize electric system configurations in ways which will reduce losses and better utilize existing assets;

**Microprocessor Relays** - Microprocessor-based relays are functionally equivalent to traditional electromechanical relays with added benefits in
performance (sensitivity and speed), reliability
(security, selectivity, and dependability),
availability, and efficiency, and contain many new
capabilities not otherwise available in older
electromechanical relays. These devices leverage
modern microprocessor technology similar to the
electronics in a modern personal computer, but are
designed specifically to meet the rigors of an
electrical substation and address the unique needs
of the application. The use of microprocessor-based
relays has already improved the overall operation
of Pepco's distribution system, ensuring that highly
flexible, yet sensitive and reliable, protection is
deployed throughout its distribution system;

**Distributed Smart RTUs** - Smart Remote Terminal Units
(RTUs) are capable of sharing information with other
devices and systems, gathering or reporting problems
on an exception basis, collecting and gathering site
information on their own, and running algorithms to
improve electric system reliability and efficiency.
The primary benefit of Smart RTUs is their ability
to manage core operational data necessary for the
efficient operation of the electric system from both
new and legacy hardware installed in electrical substations;

**Automatic Circuit Reclosers (ACR)** - ACR's are mainly used to isolate faulted sections of a distribution feeder and to also collect information such as the number of operations, magnitude of fault current, etc.;

**Automatic Sectionalizing and Restoration (ASR) Schemes** - These schemes uses multiple ACRs that are configured along a feeder, as well as ACRs that, when closed, would connect the feeder to alternate energy sources. These ACRs are controlled through distributed logic located at the substation. This enables quicker identification of the fault location and the ability to isolate the faulted section and re-energize the remaining sections of the feeder through alternative ties. The result is a faster response to faulted line conditions with a minimum impact to customers;

**Advanced Capacitor Control Systems** - Capacitors are installed along distribution circuits throughout the distribution system to reduce losses and help regulate voltage, thereby improving the efficiency of the energy delivery process. These have
traditionally been controlled by local conditions. Advanced capacitor control systems provide automatic control considering the larger system (as well as local) conditions to even further improve efficiency.

Pepco's strategy for DA deployment is an ongoing initiative and will be executed as part of an overall Smart Grid roadmap.

Q. IS THERE AN OPPORTUNITY TO OBTAIN DOE FUNDING FOR THE SMART GRID UNDER ARRA?

A. Yes. The current economic times have given rise to an unprecedented opportunity through the possibility of significant federal funding dollars available through ARRA to support projects that modernize the electric grid. Deployment of AMI meets the criteria for federal funding assistance, but an intense competition for the federal funds is expected. Pepco is seeking to take advantage of this unique set of circumstances on behalf of their customers. Pepco is asking the Commission to assist Pepco in positioning themselves at the front of the field of competitors requesting federal funding for AMI deployment.

Pepco reiterates its conclusion that AMI will revolutionize the electric industry by providing
customers with the means to make informed decisions regarding electricity consumption and enabling customers to better manage their electricity costs. The deployment of AMI is beneficial to electric customers in other ways as discussed below, and is consistent with environmental initiatives. In short, even without funding under ARRA, Pepco believes that the deployment of AMI is in the public interest.

Q. WHAT IS DOE’S AWARD CRITERIA?

A. Smart Grid grants will be awarded on a “competitive, merit based approach.” The “greatest extent of institutional and organizational commitment” is factored into the DOE evaluation, including “required approvals from regulatory organizations.” To this point, applicants will need to identify “decisions requiring external approval, e.g., the allowance of investment expenditures by Public Utility Commissions or other authorities.”

In addition to the level of demonstrable regulatory support noted above, another project evaluation criterion cited by the DOE is a project schedule “showing rapid

3 Id. at 1.
4 Id. at 13.
5 Id. at 10.
expenditure for goods and services and near-term installation of smart grid technology." Without question Pepco can clearly demonstrate their ability to comply with this requirement. Pepco has a program in place in Maryland for the installation of Direct Load Control devices including smart thermostats and Delmarva will shortly have 10,000 AMI meters installed and under a field acceptance test verifying over the air meter reads in Delaware.

**DOE’s Terms and Conditions**

Any projects receiving DOE grant assistance will require that prevailing wages be paid. "All laborers and mechanics employed by contractors and subcontractors on projects funded directly by or assisted in whole or in part by and through the Federal Government pursuant to the Recovery Act shall be paid wages at rates not less than those prevailing on projects of a character similar in the locality as determined by the Secretary of Labor in accordance with subchapter IV of chapter 31 of title 40, United States Code."7

Q. **WHAT ACTION CAN THE COMMISSION TAKE TO SUPPORT A REQUEST FOR FUNDING TO DOE?**

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6 Id. at 13.
The Commission can show support to Pepco in another critical factor guiding DOE's grant decisions - the likelihood of cost recovery by utilities in the investments in grid modernization measures. Thus, Pepco is asking the Commission to continue its support of this unique opportunity and grant explicit recognition of the needs of the Company for cost recovery by authorizing the establishment of a regulatory asset to allow the Company to defer the costs of AMI deployment between base rate cases. Not only will such recognition improve the Companies' chances of obtaining meaningful ARRA grants, it also will send positive signals to its investors in this very tough financial market. By permitting the creation of a regulatory asset, the Commission still preserves its ability to review the reasonableness of actual incurred costs before including them in customer rates after a future rate case proceeding.

Pepco recognizes that the Commission may prefer a conditional approval of the deployment of AMI at this time pending the receipt of federal funds, and Pepco believes that in this way the Commission will be able to evaluate the matter before moving ahead should the level of available stimulus funding not reach some yet to be
determined level. The Company will continue to assess
the situation as more facts become available and keep the
Commission informed as to the status of receipt of
federal funds to support AMI deployment. Pepco believes
that approval of full deployment of AMI is the correct
way to move forward with or without approval of a DOE
grant. However, a Commission decision to wait until after
any grant actions made by DOE is supported by Pepco and
the Company ask only that any Commission assessment of
the adequacy of that grant level be issued expeditiously
and in accordance with any DOE guidance in its grant
decision.

Q. PROVIDE AN OVERVIEW OF THE SMART GRID NOI.

A. The DOE issued its Notice of Intent to Issue a
Funding Opportunity Announcement for the Smart Grid
Investment Grant Program (NOI) on April 16, 2009. The
NOI contains DOE’s plan to issue a competitive Funding
Opportunity Announcement (FOA) to solicit applications
for grants for smart grid projects. The FOA is scheduled
to be issued on June 17, 2009. The NOI addresses a wide
range of issues, including grant application content and
review criteria, and the following observations do not
and are not intended to provide a comprehensive summary
of the document. In fact, as discussed in a later
section, DOE may revise portions of the FOA to improve funding opportunities. However, Pepco notes that the following four aspects of the FOA are worthy of emphasis.

**DOE's Smart Grid Definition**

DOE states, and Pepco agrees, that "the goal of a smart grid is to collect and provide the optimal amount of information necessary for customers, distributors and generators to change their behavior in a way that reduces system demands and costs, increases energy efficiency, optimally allocates and matches demand and resources to meet that demand, and increases the reliability of the grid."  

**DOE's Emphasis on Data and Analysis**

The current NOI states that grant applicants "will be required to collect data that will enable quantitative evaluation of the benefits of the technology." With regard to smart meters in particular, the DOE notes that "the most important data is hour by hour consumption" and "projects should endeavor to include commercial and industrial accounts."  

Furthermore, the DOE specifies that for grant requests involving AMI, "the applicant must describe any

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8 NOI at p. 4.  
9 Id. at 1. See also Appendix No. 3 for a summary of PEPCO's current exploration of AMI-enabled dynamic
Witness Gausman

and all time-varying or other incentive-rate structures
that are currently available or will be offered to
customers" (i.e., dynamic prices).<sup>10</sup>

**DOE’s Grant Award Criteria**

Smart Grid grants will be awarded on a "competitive,
merit based approach."<sup>11</sup> The "greatest extent of
institutional and organizational commitment" is factored
into the DOE evaluation, including "required approvals
from regulatory organizations."<sup>12</sup> To this point,
applicants will need to identify "decisions requiring
external approval, e.g., the allowance of investment
expenditures by Public Utility Commissions or other
authorities."<sup>13</sup>

In addition to the level of demonstrable regulatory
support noted above, another project evaluation criterion
cited by the DOE is a project schedule "showing rapid
expenditure for goods and services and near-term
installation of smart grid technology."<sup>14</sup> Without question
Pepco can clearly demonstrate their ability to comply

<sup>10</sup> Id. at 10.
<sup>11</sup> Id. at 1.
<sup>12</sup> Id. at 13.
<sup>13</sup> Id. at 10.
<sup>14</sup> Id. at 13.

40
with this requirement. Pepco’s sister utility Delmarva Power will shortly have 10,000 AMI meters installed and under a field acceptance test verifying over the air meter reads in Delaware.

**DOE’s Terms and Conditions**

Any projects receiving DOE grant assistance will require that prevailing wages be paid. “All laborers and mechanics employed by contractors and subcontractors on projects funded directly by or assisted in whole or in part by and through the Federal Government pursuant to the Recovery Act shall be paid wages at rates not less than those prevailing on projects of a character similar in the locality as determined by the Secretary of Labor in accordance with subchapter IV of chapter 31 of title 40, United States Code.”

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

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15 Id. at 19.
AFFIDAVIT

City of Washington )
District of Columbia ) ss:

Before me, the undersigned Notary Public in and for the City of Washington, District of Columbia, this day personally appeared WILLIAM M. GAUSMAN, Vice President, Asset Management and Planning for Pepco Holdings, Inc., to me personally known, who stated under oath that the foregoing direct testimony was prepared by him or under his direct supervision and control; that he has knowledge of the matters set forth in said direct testimony; and that such matters are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me this 21st day of May, 2009 in the City of Washington, District of Columbia.

[Signature]
Lisa A. Poole
Notary Public, DC

My Commission expires: July 31, 2012
GEORGE W. POTTS  
Direct Testimony  
D.C. P.S.C. - May, 2009  

Introduced as:  
PEPCO (B)
Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is George W. Potts. I am the Vice President, Business Transformation for Pepco Holdings, Inc., located at 701 Ninth Street NW, Washington, DC, 20068.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR ROLE AS VICE PRESIDENT BUSINESS TRANSFORMATION?

A. I am responsible for the planning, design, and implementation associated with the Blueprint for the Future for Pepco Holdings, Inc. (PHI) subsidiaries, which include Potomac Electric Power Company (Pepco), Delmarva Power & Light Company (Delmarva), and Atlantic City Electric Company (ACE). In addition, I am responsible for the coordination of our proposed Blueprint for the Future with our overall Smart Grid vision and design. This includes considering how we may alter the manner in which we interact with our customers and perform associated business processes resulting from the introduction of Smart Grid technologies.
Witness Potts

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a B.S. degree in Electrical Engineering from Drexel University in 1976 and joined Delmarva Power & Light Company as an Engineer working on Energy Management System advance power system analysis capabilities. I have served in various management positions with increasing responsibility related to the operation, maintenance and construction of both transmission and distribution systems, and Information Technology. From 1976 until 1983, I worked in Electric System Operations. From 1983 until 1989, I served as Manager of User Services and Telecommunications in our Information Systems group. From 1989 until 1992 I led the Customer Engineering group and from 1992 until 1995 led the Cable & Transmission Construction and Maintenance groups for the DP&L Northern Region. From 1995 until 1998 I was Manager of Electric System Operations and was promoted to Director in 1998 of that group. In 2002 I served as Director of Renewal investigating future operating models of the utility business. In 2003 I was promoted to Vice President of Strategic Support.
Witness Potts

1 Services for PHI and in 2007 became the Vice President of Business Transformation.

3 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AUTHORITIES?

5 A. I have appeared before the Delaware Public Service Commission and this Commission.

7 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

9 A. The purpose of my testimony is provide an overview of Pepco’s Advanced Metering Infrastructure (AMI) Business Case, provide a comparison of the costs and benefits with and without American Recovery and Reinvestment Act of 2009 (ARRA) funding scenarios. I will identify the vendor partners of the AMI technologies that Pepco Holdings, Inc. (PHI) has selected, describe the capabilities of the selected AMI technologies and provide an update on the AMI activities that PHI’s Delmarva Power operating company is conducting in Delaware.

19 This testimony was prepared by me or under my direct supervision and control. The course documents for my testimony are Company records, public documents, and my personal knowledge and experience.
Witness Potts

1 Q. PLEASE PROVIDE AN OVERVIEW OF PEPCO'S AMI BUSINESS CASE.


3 The Blueprint is designed to better enable Pepco’s customers to manage their electricity bills. With this expanded customer access to information and ability to react to price signals in the market, it is expected that regional electricity wholesale capacity and energy prices ultimately will be reduced, particularly as a result of reduced peak demands. The Business Case is comprised of Energy Delivery Benefits from AMI, Customer Savings from Reductions in Peak Loads and Costs to Deploy.

\(^{1}\) See Formal Case No. 1056, In the Matter of the Application of the Potomac Electric Power Company for Authorization To Establish a Demand Side Management Cost Recovery Mechanism and an Advanced Metering Infrastructure Rate Adjustment Mechanism and to Establish a DSM Collaborative and an AMI Advisory Group ("Blueprint for the Future" or "Blueprint") (April 4, 2007)
Q. PLEASE DESCRIBE THE ENERGY DELIVERY COST REDUCTION BENEFITS FROM AMI.

A. Below is a table from the Business Case that summarizes the estimated annual energy delivery operational benefits.

<table>
<thead>
<tr>
<th>Line</th>
<th>Benefit Category</th>
<th>In Projected 2008 Dollars, $ in 000s</th>
<th>Benefit Dollars as a % of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Eliminate Manual Meter Reading Costs</td>
<td>$1,352</td>
<td>31.5%</td>
</tr>
<tr>
<td>2</td>
<td>Implement Remote Turn-on/Turn-off Functionality</td>
<td>$1,100</td>
<td>25.6%</td>
</tr>
<tr>
<td>3</td>
<td>Improve Billing Activities</td>
<td>$776</td>
<td>18.1%</td>
</tr>
<tr>
<td>4</td>
<td>Reduce Off-Cycle Meter Reading Labor Costs</td>
<td>$368</td>
<td>8.6%</td>
</tr>
<tr>
<td>5</td>
<td>Asset Optimization</td>
<td>$612</td>
<td>14.2%</td>
</tr>
<tr>
<td>6</td>
<td>Eliminate Hardware, Software, Maintenance and Operations Cost for the Itron Handheld Data Collection System</td>
<td>$57</td>
<td>1.3%</td>
</tr>
<tr>
<td>7</td>
<td>Improve Complaint Handling</td>
<td>$32</td>
<td>0.7%</td>
</tr>
<tr>
<td>8</td>
<td>Total</td>
<td>$4,297</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

PEPCO (B)-1, pages 14 to 18, provides a comprehensive description of the estimated benefits that are likely to be realized by Pepco through deployment of the AMI System. These estimates are conservatively stated in order to assure a high probability of achievement.

Q. PLEASE DESCRIBE THE COSTS TO DEPLOY AMI.

A. Below is a table that compares the capital expenditures in PEPCO (B)-1, page 30 to a Current Forecast based upon the original estimate.
The electric meter costs in the Current Forecast column in the table above are based on the prices received from General Electric (GE) and Landis + Gyr (L+G). Note that the meter costs from GE and L+G include the cost of the Silver Spring Networks (SSN) Network Interface Card. The average meter cost, including installation, across all types of meters is $175.57. The meter costs include the final pricing for meter removal and installation from Scope Services, the contractor the Company is engaged to exchange the existing meters with the AMI meters. The communications network cost is based on the pricing received from SSN for the communication equipment installation services and network engineering design services. Included in the communications network cost is company labor for network engineering and the necessary scope of work to integrate AMI into the Company's communications network. The AMI network management system and meter data management system
include the cost of the software licenses from SSN and Itron along with software for web presentment of interval data to customers. The costs include services from outside consultants and Company labor for system integration.

The meters costs in the Current Forecast includes the actual August 2008 District Meter count which is escalated by 1% per year to allow for a 1% per year customer growth rate, compounded over the five period (2009-2013).

The project contingency includes the original business case amount of $3.5 million and the current forecast difference of -$2.6 million. As noted by Mr. Gausman, at this time we find no need to adjust our project estimate. The project estimate, based on our progress in defining and contracting for the overall scope of work to deploy AMI in the District of Columbia remains at $61.3 million.

Q. PLEASE PROVIDE A COMPARISON OF THE COSTS AND BENEFITS ON A PRESENT VALUE REVENUE REQUIREMENTS (PVRR) BASIS THAT COMPARE THE ORIGINAL BUSINESS CASE WITH POSSIBLE ARRA FUNDING SCENARIOS.

A. Below is a table that compares the Business Case with two possible funding levels the Department of
Energy has indicated in its external communications. The actual funding level may fall between the two levels.

<table>
<thead>
<tr>
<th>Description</th>
<th>Original Business Case (Dollars in Millions)</th>
<th>$20 Million DOE Grant, Prevailing Wage (Dollars in Millions)</th>
<th>Change - Increase/(Decrease) (Dollars in Millions)</th>
<th>50% DOE Grant, Prevailing Wage (Dollars in Millions)</th>
<th>Reduction (Dollars in Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Projected Cost PVRR</td>
<td>$52.2</td>
<td>$41.6</td>
<td>($10.6)</td>
<td>$31.1</td>
<td>($21.1)</td>
</tr>
<tr>
<td>Projected Energy Delivery Operating Benefits PVRR</td>
<td>$28.0</td>
<td>$29.2</td>
<td>$1.2</td>
<td>$29.2</td>
<td>$1.2</td>
</tr>
<tr>
<td>Projected Net PVRR</td>
<td>$24.2</td>
<td>$12.4</td>
<td>($11.8)</td>
<td>$1.9</td>
<td>($22.3)</td>
</tr>
<tr>
<td>Projected Capital Expenditures</td>
<td>$61.3</td>
<td>$45.8</td>
<td>($15.5)</td>
<td>$32.9</td>
<td>($28.4)</td>
</tr>
<tr>
<td>Operational Benefits/Total Cost Ratio</td>
<td>0.536</td>
<td>0.702</td>
<td>0.939</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

To compute the projected impact of a $20 million grant and a 50% match from the DOE, Pepco used the present value of revenue requirements financial model that was used in the original business case filing. The projected capital expenditures were reduced by $20 million and by 50% to demonstrate the two levels of

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2 The two DOE funding level scenarios use the final cost of capital from Formal Case No. 1053 while the Original Business Case used a preliminary cost of capital. The DOE funding level scenarios also account for the impact of the District of Columbia's Corporate Franchise Tax while the Original Business Case incorrectly did not. If the Original Business Case's PVRR values were modified to reflect these changes, then the cost, benefits and net amounts would be $54.3 million, $29.2 million and $25.1 million, respectively.
The revenue requirements model takes into account the affects lower total cost recovery and reduced total return on investment based on the decreased total Pepco investment due to the federal funding.

Included in this analysis of the costs and benefits of AMI is the additional cost of "prevailing wage rates" which are noted in the federal requirements and are above the labor costs included in our project estimate.

The results of the PVRR model as shown in the above table provide the responses to the Commission's request in its Order No. 15252 to provide:

- The cost of the project (both with and without ARRA funding).
- The benefits of the project (including a current cost/benefit analysis).

The PVRR model evaluates the costs associated with AMI, primarily the capital costs associated with deployment, and the anticipated operational savings associated with implementing the project. Revenue requirement projections are developed separately for both the cost and operating benefits. Additionally, the model provides the annual revenue requirements on
a net basis. While the net revenue requirement impact is provided in the business case, it is important to recognize that the model includes an underlying assumption that incremental capital additions will be recovered through distribution rates. The offsetting benefits would be reflected in lower operating expense levels included in future revenue requirement calculations. These lower costs will be obtained in the operational benefits as discussed by Company Witness Gausman in his testimony.

Q. WHO ARE THE VENDOR PARTNERS OF THE AMI TECHNOLOGIES THAT PHI HAS SELECTED?

A. PHI has conducted extensive reviews of AMI technology and through a competitive selection process has entered into partnerships with a number of vendors to assist in deploying AMI.

PHI has selected SSN to provide advanced networking products and services to help PHI build a Smart Grid network. According to SSN’s February 1, 2009 press release regarding its contract with PHI, “Silver Spring Networks creates the critical networking infrastructure for the Smart Grid, known as a Smart Energy Network. Based on the Internet Protocol (IP) suite, it addresses the challenges of
running multiple applications and devices on a common networking infrastructure using multiple transport technologies, dramatically improving efficiency, lowering costs and ensuring the reliable delivery of services. This smarter, more efficient grid could cut the growth rate of worldwide energy consumption by more than half over the next 15 years and drastically reduce carbon emissions."

The products being procured from SSN consist of collector radios and signal repeater devices that, together with the electric meters, will create a wireless mesh radio frequency (RF) network. SSN will also provide PHI’s selected electric meter manufacturers, General Electric and Landis+Gyr with a Network Interface Card (NIC) that GE and L+G will install inside the meters during the production process. The NIC houses radios that provide the wireless networking capability for PHI’s AMI. Using the NIC, the meter has the capability to communicate with the collector radio as well as the capability to communicate with a customer’s home area network (HAN). The customer’s HAN could include a device such as a programmable, controllable thermostat. SSN will supply a software license for its UtilityIQ™ which is
SSN’s AMI Network Management application. With regard to services, SSN will provide communication network design services, project management, field engineering services and information technology support.

PHI awarded contracts to GE to procure its I-210+c and kV2c models of electric meters and to L+G to procure its Focus AX-SD and S4e models of electric meters. Both companies’ meters include a remote connect/disconnect switch for premises served with 200 amperes or less of power. Each company received fifty (50) percent of PHI’s meter volume except for K-base meters. K-Base metering is the metering of continuous electrical loads greater than 320 amperes, using self-contained watt-hour meters and no external current transformers. This includes 400 ampere continuous duty and 480 continuous/600 ampere maximum duty meters. L+G was awarded all of the K-base meters since GE no longer produces K-base meters. The District of Columbia has about 1,200 K-base meters.

PHI signed a contact for meter exchange services with Scope Services, LLC, a Woman Owned Business Enterprise. Scope has been a contractor serving Pepco for a number of years providing a variety of meter related services.
Each vendors' 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 the District of Columbia. Although the unit prices for the meters that would be purchased for the District would be obtained at this lower price there was no commitment made to purchase these meters until approved to do so by the Commission.

Q. WHAT ARE THE CAPABILITIES OF THE SELECTED AMI TECHNOLOGIES?

A. The combination of AMI technologies Pepco has selected, when integrated into Pepco's existing operational and information technology architectures and business processes, will be able to provide, over time, the AMI related benefits identified in the Business Case and in Company Witness Gausman's testimony. Below is a summary of the features and Functionality with the associated benefits:
<table>
<thead>
<tr>
<th>Item No.</th>
<th>Feature/Functionality</th>
<th>Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hourly or 15 minute interval data recording for electric customers, depending on their rate collected on a daily basis.</td>
<td>Enable innovative rate structures, e.g., CPP, CPP Rebate, &amp; Hourly Pricing. Present customers with energy usage data. Provide customers with improved response to billing &amp; other inquiries. (Requires integration with MDMS, CIS and My Account web functionality)</td>
</tr>
<tr>
<td>2</td>
<td>Two-way radio frequency (RF) communication to the meter</td>
<td>Reduce manual meter reading while improving accuracy and lowering the number of estimated bills. Less intrusive to customers by not having meter reading personnel in or near the customer's home or business.</td>
</tr>
<tr>
<td>3</td>
<td>ANSI certified 200A full-load remote disconnect switch and on-demand meter reading</td>
<td>Enable remote turn-on/off reducing field visits and enhancing customer service, e.g. faster and better scheduled turn-ons/offs.</td>
</tr>
<tr>
<td>4</td>
<td>Tamper reporting and diagnostic alarms</td>
<td>Enhance tampering detection. Detect meter malfunctions sooner and reduce number of incorrect bills. Integration with the revenue protection module in the MDMS will proactively help the Company reduce theft of service.</td>
</tr>
<tr>
<td>5</td>
<td>Configurable outage definition and time stamped outage and power restoration reporting</td>
<td>Enhance detection and location of outage causes. Provide outage notification and estimated time of restoration information to customers as an optional service offering. (Requires integration with the Outage Management System, My Account web functionality and a notification engine)</td>
</tr>
<tr>
<td>6</td>
<td>Bi-Directional Metering, Net energy metering</td>
<td>Enable innovative rate structures, supporting</td>
</tr>
</tbody>
</table>
Additional customer benefits that could be developed over time include:

- Using individual customer load profile data to enable the utility to target specific conservation programs or messaging to individual customers.

- Employing PHI’s "My Account" software which has the capability to provide "Energy Grams" to customers offering customized energy conservation information based on how each customer is currently using energy.
- Employing PHI's "My Account" software which has the capability of providing AMI metered customers with "My bill to date," allowing customers to see how much they have spent at any point in time in a given month. The "My bill to date" feature also enables the utility to perform outbound notifications to customers letting them know when energy consumption or spending has reached customer prescribed levels. These notifications will raise awareness of energy use, contribute to changing consumer behavior towards conservation and environmental stewardship, and assist customers to better manage their monthly energy costs.

- Dynamic pricing options available through AMI will work to lower electricity consumption during peak periods, benefiting all District of Columbia customers by placing significant downward pressure on wholesale energy and capacity prices. Customers billed under dynamic prices will have the opportunity to lower their monthly electricity bills by reducing energy use during high priced periods. Customers who purchase plug-in vehicles will be encouraged by dynamic prices to recharge those vehicles during periods of lower energy prices and
not during periods of high electricity demand. The hourly data will support net metering rates for renewable generators that can reward customers through higher prices for electricity generated during high price periods.

- Enabling Customer Service Representatives (CSRs) in the Companies' Customer Contact Centers to use AMI information to quickly identify the time of high customer usage. This will enable the CSRs to offer enhanced levels of customer education by helping them to explain exactly when periods of high usage are occurring at the customer's home or business.

- Providing more accurate load data so system upgrades will only be necessary at the point of the overload and not along the entire line. In addition, transformer loading will be determined in advance of overloading the transformer, thereby reducing failures and customer outages. These activities will reduce the need for new construction projects, improve reliability and reduce O&M expenses by having fewer service requests. Furthermore, the combination of AMI and distribution automation technologies will modernize the grid to provide
smart capabilities, including improvements in
distribution system performance and restoration.

Q. HOW IS PHI’S DELMARVA POWER OPERATING COMPANY
DEPLOYING AMI IN DELAWARE?

A. Delmarva Power is currently conducting a field
acceptance test of the Silver Spring Networks AMI
system in the State of Delaware. The field acceptance
test commenced in March 2009 and is expected to be
completed no later than October 2009. The field
acceptance test is being conducted in urban, suburban,
and rural areas in two of Delaware’s three counties,
namely New Castle County and Kent County. New Castle
County includes the City of Wilmington. The test will
include about 10,000 electric meters and 2,000 gas
communication modules. PHI has retained Enspiria
Solutions, LLC to assist with the testing. The
objectives of the field acceptance test are:

- To validate the technical, functional and
  performance requirements of the selected AMI
  Technology and the AMI Communication Network back to
  the head end system by installing and operating
  approximately five to 10 thousand endpoints in
  multiple areas across Delmarva Power’s Delaware
  service territory,
To generate the information required to help make the final decision in the third quarter of 2009 for the full rollout of the AMI system. The rollout is currently expected to commence in the fourth quarter of 2009 in Delmarva Power’s Delaware jurisdiction and consists of about 300,000 electric meters and 130,000 gas modules.

To not adversely impact the customers involved in the field acceptance test,

To safely conduct the equipment installation in accordance with all applicable PHI safety rules and policies.

PHI also has a project team comprised of internal PHI personnel, personnel from PHI’s vendor partners, and consultants from IBM Global Services that is developing the information technology systems and business processes required to exchange the existing electric meters with AMI meters and in Delaware’s case, install gas meter communication modules, in large daily volumes, e.g., 1,500 to 3,000 per day.

PHI also has a team planning the physical deployment of communication network and meters and modules that will ultimately use the new deployment process.
In addition to preparing for the physical deployment of the AMI system in Delaware, PHI is working with its vendor partners and IBM Global Services to design, build, configure, test, integrate and implement selected information technologies and business processes to deliver defined benefits to Delmarva Power's customers beginning in 2010. The table below summarizes the work, which PHI refers to as the Customer Benefits System Integration project:

<table>
<thead>
<tr>
<th>Functionality</th>
<th>Current State</th>
<th>To Be State</th>
<th>Enabled by</th>
<th>Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meter Reading</td>
<td>Collect cumulative consumption data once per month in the field through a meter reader</td>
<td>Collect interval consumption data (15 minute or hourly) each day remotely through the AMI network</td>
<td>Smart Meters passing over-the-air data through the wireless communications network</td>
<td>• More frequent and timely collection of data allows for more timely billing</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Improved reading accuracy minimizes billing anomalies and allows for more accurate calculation of customer bills</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Reduces meter reading costs and access issues</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Less intrusive way for utility to collect data</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>• Include processes to verify that the meter is correct</td>
</tr>
</tbody>
</table>

Witness Potts
### Remote Connect/Disconnect

- Connect/disconnect orders are completed manually in the field.
- Connect/disconnect AMI electric meters are completed remotely through the AMI network.
- Recording properly (Alarms, flags and events)
- Reduces utility service visits, which means lower connect/disconnect costs.
- More convenient for the customer.

### Web Presentation of Usage Data

- Tools for improving residential and commercial customer tools.
- Granular historical usage information (hourly for AMI electric meters and daily for gas).
- Aclara's Load Analysis Module populated on My Account.
- Enables customers to view detailed consumption information, allowing them to determine how and when they use energy and to develop strategies for lowering their bills.
- Enables CSRs to view customer data in nearly the same format as the customer.

### AMI Portal

- Limited outage real-time data available via Navigator and monthly historical read data available in C3.
- Extensive and near real-time read data, outage data, on-demand read, and access to load analysis data via web link.
- Development of AMI Portal.
- Improved response to high bill inquiries.
- Ability to readily obtain meter readings that coincide with customer requested move dates.
- Improved customer service functionality.

---

**Witness Potts**
| Outage (OMS) | Real-time outage information at the sub-station level with no visibility at the meter level | Real-time outage information at the meter level to identify outage and restoration events | Interface between Head End (which collects meter data) and Outage Management System |

- Detects customer outages without customer calls
- PHI can acquire outage data within minutes of an event, helping to determine the type of repair likely to restore power most quickly to the greatest number of customers
- AMI data allows utilities to dispatch repair crews in a more efficient manner
- Supports more rapid customer restoration time through:
  - More accurate, near real-time meter status
  - Confirmation of restoration using "ping" functionality
- Improved outage assessments using "Last
**Witness Potts**

<table>
<thead>
<tr>
<th>Outage (Customer Communication)</th>
<th>No proactive outage notifications (customers must call PHI for outage status)</th>
<th>Customers can enroll to receive outage and restoration notification messages from PHI via e-mail or SMS text message</th>
<th>Development of Outage Notification Engine and integration with CMS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Gasp Messages’</td>
<td>• Awareness of momentary outages that could indicate a more serious service issue</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Centrally Orchestrated Message control mechanism</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Proactive messaging through text and e-mail channels</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Outage system integration with AMI</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Customer is informed of when an outage and restoration occur, even if the customer is not on site</td>
<td></td>
</tr>
</tbody>
</table>

1. Q. **PLEASE SUMMARIZE THE COSTS AND BENEFITS OF AMI.**

2. A. As depicted in the original business case and in portions of this testimony, the estimated capital cost to deploy AMI in Pepco's District of Columbia service area is $61.3M for an estimated 280,000 meters. This deployment cost includes the initial customer functionality and associated benefits which consists of remote meter reading, remote connect and disconnect, web presentation of customer usage data,
an AMI portal for company employees to support customer services, and outage detection and notification. Additional customer benefits will be developed over time in order to achieve all of the benefits anticipated in the business case. These anticipated business case benefits, as well as benefits yet to be fully detailed, will be enabled through increased integration between and among existing business systems and processes and by new business systems and processes that could be developed to fully realize the potential of the Smart Grid.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.
AFFIDAVIT

City of Washington )
District of Columbia) ss:

Before me, the undersigned Notary Public in and for the City of Washington, District of Columbia, this day personally appeared GEORGE W. POTTS, Vice President - Business Transformation of Potomac Electric Power Company, to me personally known, who stated under oath that the foregoing direct testimony and exhibit was prepared by him or under his direct supervision and control; that he has knowledge of the matters set forth in said testimony and exhibit; and that such matters are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me this 21st day of May, 2009 in the City of Washington, District of Columbia.

[Signature]
Notary Public

My Commission expires July 31, 2012
GEORGE W. POTTS
Direct Exhibit
D.C. P.S.C. - May, 2009

Introduced as:
PEPCO (B)-1
October 1, 2007

Ms. Dorothy Wideman
Commission Secretary
Public Service Commission
of the District of Columbia
1333 H Street, N.W.
2nd Floor West Tower
Washington, D.C. 20005

Re: Formal Case No. 1056

Dear Ms. Wideman:

Enclosed for filing in the above referred matter are the original and fifteen (15) copies of the Business Case In Support Of Pepco's Blueprint For The Future Application, Workpapers and the Brattle Report.

Very truly yours,

Anthony C. Wilson

Enclosures

ACW/sar

c: Parties of record
BEFORE THE
DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

IN THE MATTER OF

The Application of
Potomac Electric Power Company
For Authorization To Establish a
Demand Side Management Cost Recovery
Mechanism and an Advanced Metering
Infrastructure Rate Adjustment Mechanism
and to Establish a DSM Collaborative
and an AMI Advisory Group

Business Case
In Support of Pepco’s
Blueprint for the Future Application

On April 4, 2007, the Potomac Electric Power Company ("Pepco" or "Company") filed a
comprensive demand response, advanced metering and energy efficiency plan for Pepco’s
District of Columbia customers.¹ Now comes Pepco filing the Business Case in Support of the
Blueprint for the Future ("Business Case"), attached hereto. The Business Case, and the
attachments thereto, address the costs and benefits of the Blueprint for the Future.

Pepco’s Blueprint for the Future is designed to assist District of Columbia electricity
customers in managing energy usage, promote the conservation of energy, reduce peak
electricity demand and lessen future energy costs.² On April 23, 2007, the District of Columbia
Public Service Commission ("Commission") issued Order No. 14264, which among other things,

¹ See Formal Case No. 1056, In the Matter of the Application of the Potomac Electric Power Company for
Authorization To Establish a Demand Side Management Cost Recovery Mechanism and an Advanced Metering
Infrastructure Rate Adjustment Mechanism and to Establish a DSM Collaborative and an AMI Advisory Group
("Blueprint for the Future" or "Blueprint") (April 4, 2007).
² Id. at 1.
established the filing date for Initial Comments, Proposed Issues and Reply Comments. The Office of the People’s Counsel (“OPC”) (with the concurrence of Pepco and other parties) requested and was granted an extension of the due date for Initial Comments and Proposed Issues. Thereafter, Pepco, with the concurrence of OPC and other parties, requested an extension of the Reply Comments due date until approximately 30 days after the filing of the Business Case.

The Blueprint for the Future, which will be implemented across all of the service territories of Pepco Holdings, Inc. (“PHI”), is designed to better enable Pepco’s customers to manage their electricity bills through energy efficiency programs and an expanded opportunity to see and react to price signals in the market. With this expanded customer access to information and ability to react to price signals in the market, it is expected that regional electricity wholesale capacity and energy prices ultimately will be reduced, particularly as a result of reduced peak demands.

As described in Blueprint Application, Pepco is seeking authorization to administer demand side management (“DSM”) programs and to recover the non-capital costs associated with these programs through either the existing Reliable Energy Trust Fund (“RETF”) surcharge or a new distribution surcharge. The formal set of DSM programs will be developed through a proposed DSM Collaborative. In addition, Pepco is seeking authorization to establish a separate

---

3 See Order No. 14264 (April 23, 2007).
4 Motion for an Extension of Time to Submit Initial Comments ... (June 29, 2007). And see Order No. 14371, Granting Motion for an Extension of Time to Submit Initial Comments ... (July 13, 2007).
5 To date, the Commission has not addressed the motion.
6 PHI is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 1.9 million customers in Delaware, the District of Columbia, Maryland, New Jersey and Virginia. PHI subsidiaries Pepco, Delmarva Power and Atlantic City Electric provide regulated electricity service; Delmarva Power also provides natural gas service. PHI provides competitive wholesale generation services through Conectiv Energy and retail energy products and services through Pepco Energy Services.
Advanced Metering Infrastructure ("AMI") rate adjustment mechanism to recover the costs associated with the installation of advanced metering infrastructure and capital cost of a smart thermostat system that will enhance reliability and better serve our customers. In association with the rollout of AMI, Pepco also is requesting that the Commission establish an AMI Advisory Group that Pepco will keep apprised of the scheduled rollout, technology to be used, data enhancements and other issues related to AMI. Alternatively, the Smart Meter Working Group, established by the Commission's March 23, 2007 Order No. 14239 in Formal Case No. 1049, can be authorized to advise the Company on its AMI implementation plans.²

The Business Case, and the attachments thereto, address the costs and benefits of the Blueprint for the Future.

Respectfully submitted,

Anthony C. Wilson
Associate General Counsel
Potomac Electric Power Company

Kirk J. Emge, D.C. Bar No. 420581
Deborah M. Royster, D.C. Bar No. 359087
Anthony C. Wilson, D.C. Bar No. 417508
Keith Townsend, D.C. Bar No. 393292
701 Ninth Street, N.W., Suite 1100
Washington, D.C. 20068
(202) 872-2097

Counsel For Potomac Electric Power Company

Washington, D.C.
October 1, 2007

² In addition to the 1049 Working Group, Pepco, pursuant to the settlement agreement in Formal Case 1002, is currently involved with Smart Meter Pilot Program, Inc. ("SMPPI") and the pilot deployment and analysis of approximately 2,000 smart meters across the District of Columbia. Additionally, Pepco's Blueprint proposals, armed with data coming from SMPPI and other sources including Formal Case 1049, goes beyond the limited scope of SMPPI to include every customer in the District of Columbia.
CERTIFICATE OF SERVICE

I hereby certify that on this 1st day of October, 2007, a copy of the foregoing was sent by first class, postage prepaid, to all parties of record in Formal Case 1056.

Anthony E. Wilson  
Associate General Counsel  
Potomac Electric Power Company  
701 Ninth Street, N.W., Suite 1100  
Washington, D.C. 20068  
(202) 872-2097
Business Case
In Support of
PEPCO's Blueprint for the Future Application
Formal Case No. 1056

Filed October 1, 2007
Overview


The Business Case, and the attachments thereto, address the costs and benefits of the Blueprint for the Future. The Blueprint for the Future, which will be implemented across all of the service territories of Pepco Holdings, Inc. ("PHI"), is designed to better enable Pepco's customers to manage their electricity bills through energy efficiency programs and an expanded opportunity to see and react to price signals in the market. With this expanded customer access to information and ability to react to price signals in the market, it is expected that regional electricity wholesale capacity and energy prices ultimately will be reduced, particularly as a result of reduced peak demands.

Pepco, because of the relationship it has with and knowledge it has about its electricity customers, is uniquely positioned to implement these programs. The Blueprint builds on the work the Company has already begun through the Utility of the Future and other initiatives. With the full implementation of the Blueprint, Pepco and its customers can make a sizeable contribution to meeting the District of Columbia's energy conservation challenges. The Blueprint for the Future charts the course to give customers what they tell us they want: tools to manage and monitor their electricity usage, responsive customer service; and environmental

---

1 See Formal Case No. 1056, In the Matter of the Application of the Potomac Electric Power Company for Authorization To Establish a Demand Side Management ("DSM") Cost Recovery Mechanism and an Advanced Metering Infrastructure Rate Adjustment Mechanism and to Establish a DSM Collaborative and an AMI Advisory Group ("Blueprint for the Future" or "Blueprint") (April 4, 2007).

2 See Brixie Report (September 21, 2007), And see Business Case Working Papers.

3 PHI is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 1.9 million customers in Delaware, the District of Columbia, Maryland, New Jersey and Virginia. PHI subsidiaries Pepco, Delmarva Power and Atlantic City Electric provide regulated electricity service; Delmarva Power also provides natural gas service. PHI provides competitive wholesale generation services through Connect Energy and retail energy products and services through Pepco Energy Services.
stewardship — all of which can lead to reduced usage and peak demand reductions.

Pepco is deploying a number of innovative technologies. Some, such as the automated distribution system, will help to improve reliability and workforce productivity, while others, including an Advanced Metering Infrastructure ("AMI"), will enable our customers to monitor and control their electricity use, reduce their energy costs and enable their participation in innovative rate options. As more fully set forth in the Blueprint Application, filed April 4, 2007, an overview of what’s planned is below.

**Demand Side Management (DSM) Programs**

In the late 1980s and 1990s, Pepco was a national leader in the provision of DSM programs for its customers. By 2001, Pepco’s DSM programs had achieved service area wide peak demand reductions of approximately 790 MW and annual energy reductions exceeding 1.9 million MWh. Pepco believes that it is vital that new DSM programs be initiated in the District of Columbia at this time. The Company believes that it is in the best position to successfully implement an aggressive portfolio of DSM programs in the District of Columbia at this time. Pepco provided a recommended list of cost-effective DSM programs in its Blueprint filing and recommended that program costs be recovered through either a new distribution DSM surcharge or through the existing Reliable Energy Trust Fund ("RETF") surcharge. Pepco notes that many more DSM initiatives would be cost-effective if the Commission were to adopt a broader societal cost-effectiveness test that captures the significant value related to reducing power plant air emissions. The Company urges the Commission to adopt this broader cost-effectiveness test due to the increasing concerns over the negative externalities resulting from power plant air emissions.

In Pepco’s Blueprint filing, the Company requested that the Commission permit the establishment of a Pepco specific DSM Collaborative. Participation in the Collaborative would include interested District of Columbia energy market stakeholders to work with Pepco in a collaborative manner to develop a final set of recommended Pepco managed DSM programs that would be submitted to the Commission for its approval. The Company is implementing its first new DSM program in Maryland at this time, a residential high efficiency lighting program.
The deployment of an AMI System is a critical component of reducing peak electricity demand in the District of Columbia and providing the vital information needed to enable customers to better control their monthly energy costs.

**Automated Metering Infrastructure (AMI)**

Pepco is currently working with the Smart Meter Pilot Program, Inc. ("SMPPI") to implement a smart metering pilot program in the District of Columbia. Members of SMPPI include Pepco, the District of Columbia Public Service Commission, the Office of the People's Counsel, the District of Columbia Consumer Utility Board, and the International Brotherhood of Electrical Workers. The AMI equipment for participating customers is being installed at this time. This pilot was initiated as the result of the Pepco/Conectiv merger settlement agreement, whereby the Company agreed to contribute $2 million towards a smart metering pilot initiative. The pilot is designed to test residential customer response to three rate options based upon Pepco Zonal day-ahead PJM Locational Marginal Prices: 1) hourly pricing, 2) critical peak pricing, and 3) critical peak rebates. A portion of pilot program participants will receive a smart thermostat to help them to reduce their summer air conditioning load during high priced periods. The purpose of the District of Columbia pilot is to test customer response to different rate options and billing statements rather than to test any AMI or smart thermostat technology. The results gathered from the study will be used by Pepco to develop appropriate rate options for customers that will be supported by the Company's universal AMI deployment plan.

The Company, under Commission direction, proposes to work collaboratively with interested parties, in existing working groups (such as that formed in Formal Case No. 1049) or in to be formed working groups, to plan the installation of an AMI system. The AMI system will provide detailed usage data to customers, electricity suppliers and to the Company. The AMI system will not only enable customers to track and modify their electric use, but it will also help the Company make improvements to customer reliability, outage detection and management, and billing accuracy and timeliness.

**Environmental Initiatives / Considerations**

The deployment of an AMI System will support innovative customer rate options that will help to support plug-in vehicles and small-scale renewable
The grid integration of additional small-scale renewable generation will help District of Columbia electricity suppliers meet the District's Renewable Portfolio Standards requirements. As part of PHI's multifaceted environmental initiatives, PHI is also laying the groundwork to transform its 2,000-vehicle fleet to more environmentally friendly technologies. The Company is already using Biodiesel at PHI fueling sites; Pepco, for its part, has replaced a number of our fleet vehicles with hybrid vehicles; and the Company is collaborating with the Electric Power Research Institute ("EPRI") on a project to demonstrate plug-in gasoline/electric vehicles.

In addition to these programs, the demand response efforts enabled by this technology will reduce dependence on peaking sources of generation, while the technology will improve Pepco's access to greener sources of distributed renewable supply.

**Pepco's Blueprint for the Future Plan**

Over the past several years the rising cost of energy across the nation has adversely affected Pepco's customers. Customers, absent real information, have only a limited ability to lower their energy usage and to reduce the added burden of higher energy costs. Pepco has communicated with its customers and attempted to provide them with options to more efficiently manage their energy use. Last year PHI and Pepco launched the "Energy Know How" campaign, which was recently re-introduced under the name of "My Account". PHI and Pepco invested over $1,000,000 to implement state of the art energy auditing software. This valuable service now enables Pepco's residential customers to go on the internet and view data about their monthly bills to better understand how they use energy and what changes might reduce their overall costs. The Blueprint is Pepco's proposal to take the District of Columbia's customers to a higher efficiency level.

This filing is the next step in answering customer concerns by giving customers more robust energy efficiency tools to reduce electricity consumption and demand response programs that will help to change when customers use energy in an effort to reduce peak demands, driving total electricity costs down for the District. The data and communications capabilities inherent in the advanced metering proposal that Pepco has set forth will provide a platform upon which to build a number of programs aimed at managing overall energy costs.
Components of the Pepco AMI business case

The Business Case is comprised of four major components: Energy Delivery Benefits from AMI, Customer Savings from Reductions in Peak Loads, Cost to Deploy, and Accelerated Depreciation of metering equipment. The information contained in each of these components is further described below and detailed in the body of this report.

1 - Energy Delivery Cost Reduction Benefits from AMI

Savings in operating costs captures O&M and capital savings expected to be realized once the AMI is implemented. These savings or benefits will include:

- Meter Related Benefits
- Customer Contact Benefits
- Asset Optimization Benefits
- Additional Benefits

2 - Customer Savings from Reductions in Peak Loads

The Brattle Group was retained to estimate customer savings that Pepco DC's proposed investment in AMI is likely to achieve by reducing peak loads. The two major categories of benefits that Brattle quantified are: (1) "resource cost savings," i.e., reducing the quantity of capacity, energy, and ancillary services that customers must buy (or enabling them to sell those products); and (2) "short-term market price impacts," i.e., depressing wholesale market prices for energy and capacity. The benefits are estimated consistently with the January, 2007 Brattle Study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), with several additional analytical elements.

The resource cost savings reflects the fact that every MW reduction in peak load lessens the need for physical capacity, which customers pay for through their suppliers. Similarly, every MWh reduction in consumption lessens the quantity of generation that customers must buy during peak periods when energy prices are very high.
In general, the market price impacts reflect the fact that even a small reduction in demand during tight market conditions lowers the market price for energy, thus lowering the cost of energy for all customers (not just those curtailing load), as illustrated in Figure 1. Similarly, reducing the peak demand lowers the demand for capacity and thus reduces market prices for capacity, which affects all customers.

Figure 1: The Brattle-PJM-MADRI Study Showed How Even Small Changes in Demand Can Lead to Large Changes in Prices and Customer Benefits

3 - Cost to Deploy

Cost to Deploy includes the cost of the capital investments associated with building out the AMI system. Deployment costs included are; meters and installation, communications network infrastructure and installation and the associated information technology systems and integration, including the meter data management system (MDMS). Also included in the Cost to
Deploy are the incremental operating costs for the AMI system. Incremental operating costs include O&M expenses associated with operating the AMI. This includes; MDMS Software, Maintenance and license fees, AMI network management software maintenance and license fees, hardware lease expense for application and storage servers and expenses related to the communications network infrastructure.

4 - Accelerated Depreciation

The deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure. These impacts have been reflected in the analysis. Depreciation calculations may be updated due to pending Federal legislation.

Conclusions

The Pepco AMI business case is financially justified by the operational benefits and the demand response benefits to the Company and our customers. The estimates for demand response benefits from the AMI deployment, over a 15 year period, is $29 million estimated using the most conservative of scenarios. Coupled with operational savings of $28 million, results in a positive $4.8 million Present Value Revenue Requirement (PVRR) over the same period. Using the best case for Demand Response (DR) benefits, results in a positive $44.8 million PVRR. These financial benefits together with electric distribution customer service enhancements make the case for AMI deployment compelling in the District of Columbia. Notably, if AMI is deployed more broadly through the Mid-Atlantic region of PJM, resulting savings increase significantly. Figure 2 demonstrates the potential range of savings under different scenarios.

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4 See infra, Figure 2, Scenario #1.
5 See infra Figure 2, Delivery Company Benefit. See also Figure 3.
6 See infra, Figure 2, Best Case Scenario #6.
Figure 2

PHI contracted with the Brattle Group to develop six scenarios of customer and supplier response to AMI. Figure 2 above, shows the relationship of each of these six scenarios compared to the PVRR Cost and Benefit. The two cases, upside and low, for each scenario are the result of sensitivities associated with variations in market conditions. These conditions include possible fluctuations in fuel prices, and or high peak years (usually weather driven). If the other energy distributors in PJM deploy AMI, the benefit to Pepco customers is estimated to be as high as $210 million.  

7 See Brattle Report at page 65.
The results of this analysis yields two key conclusions: (1) AMI is a net positive investment even in the lowest value scenario; (2) the benefits from AMI-enabled DR will be more than twice as large if dynamic pricing is the default rate structure than if it is merely an option that customers can elect.
Figure 3 summarizes the PVRR for Pepco DC.

<table>
<thead>
<tr>
<th>Line</th>
<th>AMI System Components</th>
<th>Initial Deployment Costs</th>
<th>Annual Estimated Costs After Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>District of Columbia</td>
<td>Only, $ in '000s</td>
<td>$ in '000s</td>
</tr>
<tr>
<td>1</td>
<td>Meters, including Installation Cost</td>
<td>$35,780</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Communications Network, including Installation Cost</td>
<td>$18,304</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>AMI Network Management System and Meter Data Management System</td>
<td>$3,740</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Contingency</td>
<td>$3,488</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Capital Expenditures</td>
<td>$61,272</td>
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</table>

<table>
<thead>
<tr>
<th>Line</th>
<th>AMI System Incremental Cost to Operate</th>
<th>District of Columbia</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>MDMS Software Maintenance &amp; License Fees</td>
<td>$62</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>MDMS Hardware Leasing</td>
<td>$142</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>AMI Network Management System O&amp;M</td>
<td>$188</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Communications Network Infrastructure O&amp;M</td>
<td>$185</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Total Incremental Cost to Operate</td>
<td>$527</td>
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</tr>
</tbody>
</table>

**15 Year Revenue Requirement of Total Costs**: $52.2 million

<table>
<thead>
<tr>
<th>Line</th>
<th>Benefit Category</th>
<th>In Projected 2008 Dollars, $ in '000s</th>
<th>District of Columbia</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Eliminate Manual Meter Reading Costs</td>
<td>$1,352</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Implement Remote Turn-on/Turn-off Functionality</td>
<td>$1,100</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Improve Billing Activities</td>
<td>$776</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Reduce Off-Cycle Meter Reading Labor Costs</td>
<td>$388</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Asset Optimization</td>
<td>$612</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Eliminate Hardware, Software, Maintenance and Operations Cost for the Iron Handheld Data Collection System</td>
<td>$57</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Improve Complaint Handling</td>
<td>$32</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Total</td>
<td>$4,297</td>
<td></td>
</tr>
</tbody>
</table>

**15 Year Revenue Requirement of Operating Benefits**: $28 million
Organization of this Report

For the preparation of this report, PHI gathered information from both internal and external subject matter experts, including IBM and the Brattle Group, as well as from other utilities across the country. This report represents the current state of thinking for AMI deployment based upon available information.

Key points are as follows:

- This Business Case focuses on Pepco – DC but also considers incorporates the deployment of an AMI system throughout all PHI jurisdictions.\(^8\)

- Cost and Benefit estimates are conservatively stated in order to assure a high probability of achievement.

- While many benefits are immediately available as the AMI System is deployed, timing of the full benefits associated with an AMI system is assumed to begin following the complete deployment.

- Business Case Financial Assumptions:
  - 15 year Present Value Revenue Requirement model, with multiple jurisdictions modeled
  - Meter Deployment assumed 100% of Pepco DC meters in 2011:
  - Meter growth is assumed to be 1% per year
  - 3% labor and expense annual escalation rate
  - Cost of Capital – 7.09%
  - Tax rate 40.4% for all jurisdictions

- Depreciation:
  - New meter and meter communications equipment - 15 yrs
  - Existing meter and equipment – 5 years
  - IT Capital Cost - 5 years

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\(^8\) As always final numbers are subject to change based on the programs selected and the actual costs.
Energy Delivery Cost Reduction Benefits from AMI

This section of the report describes the estimated benefits that are likely to be realized by Pepco through deployment of the AMI System and the associated MDMS. Pepco proposes to use these quantified benefits to help offset the costs associated with AMI and MDMS in the proposed AMI Adjustment Mechanism as described in the April 4, 2007, Blueprint for the Future filing with the Public Service Commission of the District of Columbia. Figure 4 below summarizes the annualized benefits and under the Figure are more detailed descriptions of each benefit.

<table>
<thead>
<tr>
<th>Pepco Benefit Category</th>
<th>In Projected 2008 Dollars, $ in 000s</th>
<th>Benefit Dollars as a % of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Eliminate Manual Meter Reading Costs</td>
<td>$ 1,352</td>
<td>31.5%</td>
</tr>
<tr>
<td>2. Implement Remote Turn-on/Turn-off Functionality</td>
<td>$ 1,100</td>
<td>25.6%</td>
</tr>
<tr>
<td>3. Improve Billing Activities</td>
<td>$ 776</td>
<td>18.1%</td>
</tr>
<tr>
<td>4. Reduce Off-Cycle Meter Reading Labor Costs</td>
<td>$ 368</td>
<td>8.6%</td>
</tr>
<tr>
<td>5. Asset Optimization</td>
<td>$ 512</td>
<td>14.2%</td>
</tr>
<tr>
<td>6. Eliminate Hardware, Software, Maintenance and Operations Cost for the Iron Handheld Data Collection System</td>
<td>$ 57</td>
<td>1.3%</td>
</tr>
<tr>
<td>7. Improve Complaint Handling</td>
<td>$ 32</td>
<td>0.7%</td>
</tr>
<tr>
<td>8. Total</td>
<td>$ 4,257</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

1) Eliminate Manual Meter Reading Costs

This is the largest operational benefit expected to be realized after full deployment of the AMI system. Pepco uses an outside contractor to read its electric meters in the District of Columbia which would no longer be needed to perform its present functions with full deployment of AMI. The Company expects to design and configure the AMI System such that all District of Columbia customers will have meters that are reachable (readable) by the AMI’s communications network infrastructure. Pepco projects that the elimination of the need to manually read meters would result in annualized O&M expense savings of $1.4 million (expressed in projected 2008 dollars). The O&M expense savings estimate is based on projected meter reading volume multiplied by the per read rates specified in the contract with the outside contractor.

The quantification of these benefits will be refined as Pepco conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated value of the benefits.
The initial year was assumed to be 2008 therefore the 2007 O&M expense savings as described above were escalated three percent (3%) to account for expected wage and inflation increases. The 3% percent escalation factor was also used to grow the estimated annualized savings in the remaining years of the revenue requirements schedule.

2) Implement Remote Turn-on/Turn-off Functionality

Pepco's current assumption is that a switch will be available inside the meters that will permit the Company to remotely connect and disconnect 200 Ampere and lower electric service. This assumption is consistent with AMI recent experiences and plans of other utilities and requirements of other state public service commissions.

The estimated savings would come from avoiding field visits to customers' premises for collection reasons, both the initial cut/collect field visit and the reconnection field visit, if such a reconnection visit was requested by the customer. Based on a review of 2006 data from the Company's records, about 39% of Pepco's system wide disconnections for collection reasons occurred in the District of Columbia. The Company tracks the system wide cost of disconnection and reconnection work in two separate orders in its accounting system. The costs are comprised of the fully loaded labor costs of Pepco field cut/collectors and contractor costs for the reconnection work. The loadings added to internal labor costs are for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. This analysis allocated 39% of the costs to the District of Columbia. By eliminating these field visits, The Company could obtain savings at an estimated annualized $1.1 million (expressed in projected 2008 dollars).

Remote turn on/turn off capability will benefit all customers, especially those subject to disconnection for non-payment. Currently Pepco's tariff specifies that if a disconnected customer requests to be reconnected, then a charge of $35.00 is required. With the AMI System's remote connection and disconnection functionality, this charge could be significantly reduced (estimated in the range of $5 to $10). The reconnection could be accomplished remotely from Pepco's offices, after the customer calls the Company to verify payment, rather than dispatching a person to the customer's premise. This reduces the financial burden on those having difficulty paying their bills. This method is also safer for employees who perform this type of work.
3) Improve Billing Activities

With the deployment of AMI, the Company expects to significantly reduce the number of exceptions that it currently addresses in its back office billing department. These exceptions include such transactions as estimated bills, consecutive estimations, high/low consumption and other checks. As of June 2007, Pepco employed a total of 29 back office billing analyst and supervisory personnel to handle the system wide exceptions work volume. For this benefit, Pepco assumed 90% of the exceptions work volume would be eliminated with full deployment of AMI. The savings estimate was computed by multiplying the possible reduction in FTEs by a 2007 fully loaded annual labor cost per FTE which took into account the cost mix of employees (analysts and supervisors) doing the work. The fully loaded annual labor costs included the same costs that were described in the remote turn-off/turn-on functionality benefit, as described above. This allocated portion of the savings amounted to an estimated annualized $0.8 million (expressed in projected 2008 dollars) for the District of Columbia. Note that if less than 90% of the exception volume is ultimately realized, then the savings estimate will be adjusted accordingly.

The savings were allocated to the District of Columbia using 2007 average budgeted customer counts as the allocation factor. This allocation factor is presented in the Figure below.

**Figure 5**

<table>
<thead>
<tr>
<th>Allocation based on 2007 Budgeted Customer Counts</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pepco-DC</td>
<td>236,930</td>
<td>31%</td>
</tr>
<tr>
<td>Pepco-MD</td>
<td>516,725</td>
<td>69%</td>
</tr>
<tr>
<td>Combined</td>
<td>516,725</td>
<td>69%</td>
</tr>
</tbody>
</table>

The 2007 dollars in Figure 5 above were escalated by three percent (3%) to account for 2008 estimated wage increases which increases the dollars in Figure 5 from $753,000 to $776,000.

4) Reduce Off-Cycle Meter Reading Labor Costs

Pepco typically uses special meter readers to obtain meter readings outside of the normally scheduled meter reading routes for a variety of reasons. These reasons include when a customer moves out of a premise and a new customer moves in shortly thereafter and asks the billing department or the call center to check a reading in the field. With the full
deployment of AMI, these "check reads" can be obtained remotely from Pepco's offices eliminating the need for a field visit. When computing the estimated savings associated with this benefit, any costs from meter readers were excluded. Those savings are included in meter reading benefit described above.

As of June 2007, Pepco employed a total of ten special meter readers. For this benefit, Pepco assumed all of the off-cycle meter reading work volume would be eliminated with full deployment of AMI. The value of savings was computed by calculating the annual cost of the ten special meter readers using a 2007 fully loaded annual labor cost per employee. The fully loaded annual labor costs included the same costs that were described in the remote turn-off/turn-on functionality benefit above. The Pepco system wide savings were allocated to the District of Columbia using 2007 average budgeted customer counts as the allocation factor. This allocated portion of the savings amounted to an estimated annualized $0.4 million (expressed in projected 2008 dollars).
5) Asset Optimization

AMI deployment will improve the quality of customer outage status and hence will reduce the field restoration efforts associated with “false” power outages. Pepco experiences approximately 1000 power outage calls annually where upon arrival at the customer locations, the emergency response team finds that there is no electric service problem from Pepco but the problem is on the customer side of the meter or in the house. Similarly, during storms, the Company responds to 1500 outage requests annually which have been already restored previously but not recorded in the Company outage management system. AMI capabilities will eliminate these unproductive trips as well as reduce the number of Call Center calls and will result in estimated savings of $320,000. AMI deployment also will improve Pepco’s asset management program and will result in accurate sizing of transformers and fuses. This will result in reduced outages and is expected to reduce number of field trips by 250 annually. It will also reduce field trips associated with special load readings at substations. The savings associated with this benefit is $145,000 annually. Accurate outage data and system conditions will significantly improve restoration efforts and eliminate duplicate field visits, which is projected to result in savings of approx $145,000.

6) Eliminate Hardware, Software, Maintenance and Operations Cost

PHI currently pays maintenance fees on its existing metering reading devices. With the deployment of AMI, these costs would be eliminated. The costs and savings were allocated using a 2007 average budgeted customer counts as the allocation factor.

7) Reduced Complaint Handling

For this benefit, PHI is assuming the data from AMI will, over time, contribute to fewer complaints and that the company representatives may be able to more quickly resolve complaints. The current assumption is that the complaint handling group may be able to improve its work flow and then reduce the equivalent of one full time equivalent. The O&M expense savings for the one FTE is based on the actual salary for a company representative with the applicable loading for payroll taxes and benefits such as medical coverage, dental coverage, pension and other post retirement benefits. The costs and savings were allocated using a 2007 average budgeted customer counts as the allocation factor.
Customer Savings from Reductions in Peak Loads

The Brattle Group was retained by PHI to estimate the value to customers of load reductions resulting from PHI's proposed investments in demand-side management (DSM) initiatives, including energy efficiency, direct load control, and deployment of advanced metering infrastructure across the utility system (Pepco – DC, Pepco – MD, Delmarva – DE, Delmarva – MD, and Atlantic City Electric). The Brattle Group's analysis involves two major components: first, determining the magnitude of load reductions that are likely to be achieved; and second, estimating the customer value of such load reductions.

1) Estimated Load Reductions

Load reductions associated with PHI's proposed programs involving energy efficiency and AMI-enabled direct load control are taken directly from PHI's most recent Blueprint Filing for its DSM programs. Load reductions associated with AMI-enabled critical peak pricing (CPP) programs were estimated using the PRISM model, which is based on empirical data from the California Statewide Pricing Pilot and is calibrated to the load characteristics of residential and small commercial customers in Pepco. The load reductions can be estimated for cases where CPP is either a voluntary or default rate structure. Both cases are shown in Figure 6.
2) Analysis of Customer Benefits from Load Reductions

Reducing peak load benefits customers in several ways, including: (1) providing “resource cost savings” by reducing the quantity of capacity, energy, and ancillary services that customers must buy (or enabling them to sell those products); (2) creating “short-term market price impacts,” i.e., depressing wholesale market prices for energy and capacity; (3) improving reliability; (4) enhancing market competitiveness; (5) reducing rate volatility; (6) reducing transmission distribution losses; and (7) potentially obviating or delaying the need for investments in transmission and distribution.

The customer benefits detailed in this report focus on items one and two above. The other categories of benefits have not been quantified because the economic methodologies involved are not well developed or
standardized. Therefore, the total benefits of reducing load could be substantially larger than the limited set of benefits reported in this Business Case.

The Brattle Group has estimated the benefits to Pepco's District of Columbia customers from resource cost savings and market price impacts consistent with its January, 2007 study, "Quantifying Demand Response Benefits in PJM," sponsored by PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI), but with several additional analytical elements.

**Resource Cost Savings**

Capacity savings reflect the fact that DR lowers the load forecast, which lessens the amount of capacity that load-serving entities must purchase from generation suppliers through contracts or through PJM's capacity market. Alternatively, load that is controlled directly by the utility can provide capacity, thus offsetting the need for physical capacity. The value of either approach — reducing the capacity requirement or contributing capacity — can be evaluated using a projected price of capacity. Brattle estimated the future capacity price using the Net Cost of New Entry (Net CONE) that PJM uses in its definition of capacity market parameters. Net CONE is a conservative proxy because the capacity price has been higher than Net CONE in recent auctions for the 2007/08 and 2008/09 delivery years. Net CONE is also less than the avoided capacity cost often used in DSM plans, which often does not net out the marginal value (i.e., operating margins) that new generation would provide by selling energy and ancillary services.

Generation savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not constructed and old capacity retired or not dispatched. The value of reduced generation is also partially offset by the value the customer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult and depends on whether the customer shifts load to lower-priced periods. These issues were addressed in the Brattle-PJM-MADRI study, in which generation savings amounted to an additional 12-36 percent on top of the capacity savings. Brattle's analysis of AML-enabled DR in Pepco simply adopts these figures by adding 12-36 percent of the estimated capacity savings.
Some DR could provide spinning reserves or other ancillary services (A/S), which would reduce the need for reserves from supply-side resources, the marginal value of which is given by the market price for spinning reserves. However, ancillary service value is somewhat speculative because currently none of PHI’s DSM programs plan to enable ancillary services, although other DR does provide small amounts of A/S in PJM and ISO-NE\textsuperscript{10}.

\textbf{Short-Term Price Impacts}

Short-term energy price reductions are estimated by adapting the results of the Brattle-PJM-MADRI study (January, 2007) to reflect the load reductions expected from PHI’s programs. As in the Brattle-PJM-MADRI study, the “benefit” is given by the product of the estimated price reduction and the load exposed to market prices. Benefits are partially offset by an associated reduction in the value of Financial Transmission Rights ("FTRs") (about a 15% offset). To the extent that PHI’s load reductions differ from the load reductions simulated in the Brattle-PJM-MADRI study, Brattle linearly extrapolated the price impacts (e.g., twice the amount of load reductions would lead to twice the price impact).

While the Brattle-PJM-MADRI study assumed that all non-curtailed load was exposed to market prices, the present analysis assumes conservatively that only a fraction of load is exposed to market prices. The remainder is unaffected because it is covered by pre-existing contracts that were priced without anticipating the effects of DSM. Roughly corresponding to the contract lengths and schedules by which standard offer service is procured in DC, DE, and MD and basic generation service in New Jersey, Brattle assumed that in any given year 50\% of load-serving obligations are supplied by pre-existing wholesale contracts, and 50\% are supplied by new contracts. This assumption results in discounted customer benefits relative to the Brattle-PJM-MADRI study — a 50\% discount in the “Immediate Supplier Reaction” Supply Response scenario and a 17\% discount in the “Slower” scenario discussed below.

A second difference from the Brattle-PJM-MADRI study is the quantification of real-time DR benefits. The Brattle-PJM-MADRI study assumed conservatively that A&M could eventually enable 100 MW of spinning reserves from loads that can be curtailed within less than 30 minutes of notification and stay offline for as much as 4 hours, such as electric arc furnaces or chillers in supermarkets. Hence potential ancillary service value is estimated by multiplying a conservative quantity of spinning reserves by the historical average price of spinning reserves (2004-05) of $8.5/MMWh and by the number of hours in a year.
quantified benefits for only day-ahead DR and discussed qualitatively the potential additional value from DR that is dispatchable in real-time and thereby able to mitigate the effects of real-time surprises in supply and demand. In its present analysis of DSM in Pepco, Brattle assumed that loads under direct load control were dispatchable in real-time, and estimated the premium using the ratio of historical super-peak RT prices to super-peak DA prices. Brattle also estimated the additional value if dynamic pricing could designate peak periods on the day-ahead rather than day-ahead.

A third difference is that Brattle’s present analysis includes an estimate of the capacity price impact from DR, whereas capacity price impacts were outside the scope of the Brattle-PJM-MADRI. Participation of DR in capacity markets is an important element of PJM’s newly instituted Reliability Pricing Model (RPM). While only the subset of load reductions, those that are under direct control (by the utility, other retail providers, curtailment service providers or the RTO), can participate as supply in capacity markets (Smart thermostat), the expected effect of dynamic pricing programs would also impact capacity prices by reducing the load forecast and thus the administratively-determined demand for capacity. Given this new market reality, Brattle has estimated capacity price impacts as follows: in the “Immediate” and “Slower Supplier Reaction” scenarios (defined below), the market was assumed to be in supply/demand balance with the expected 3-year forward capacity price set by Net CONE, irrespective of the level of load reductions achieved. Hence, the capacity price impact was conservatively set at zero in these scenarios. In the “Delayed Supplier Reaction” scenario, capacity price impacts were estimated by intersecting supply and demand curves for capacity in the Eastern MAAC Locational Delivery Area both with and without DR. The demand curve was constructed using PJM’s load forecast and the other parameters it uses to determine the administratively-determined demand curve. The supply curve was constructed by adding projected new supply (from the generation interconnection queue) to the supply curve available from the most recent capacity auction.

**Scenario Definition**

A key insight is that the resource cost savings from reducing peak loads persist over time, whereas the market price impacts can be expected to diminish as suppliers respond to depressed prices by delaying the construction of new generation or accelerating the retirement of existing plants. The magnitude and duration of the price impact depends on the
rate at which suppliers respond to changes in market conditions and on the tightness of the market over the next several years. Price impacts are the largest and the longest-lasting in a scarcity situation; they are the smallest and shortest-lived in a surplus market or in a balanced market in which suppliers react quickly to DSM's successes (and associated price impacts) by delaying construction of new capacity or accelerating the retirement of existing plants. Hence, Brattle analyzed a range of plausible market conditions by constructing three supplier scenarios in which the longevity of price impacts is varied:

- In the "Immediate Supplier Reaction" scenario, the market is in supply-demand equilibrium, and suppliers react quickly to changes in fundamentals. Short-term energy price impacts (which are derived from the Brattle-PJM-MADRI study, which used a short-term equilibrium model in which supply was static), last for only one year before suppliers fully react. One year after the introduction of new DR, suppliers have accelerated enough retirements and/or delayed enough new construction to completely offset the price impact of DR. Hence, if PHI's deployment schedule produces 200 MW or peak load reduction in year n and 300 MW in year n+1, only 100 MW of load reductions has a price impact in year n+1. This scenario is consistent with the observation that suppliers in the recent Reliability Pricing Model (RPM) Base Residual Auction quickly changed their plans by delaying retirements presumably in response to high Eastern prices in the prior auction.

- The "Slower Supplier Reaction" scenario is similar to the Immediate scenario except that short-term price impacts last for three-years before suppliers respond. The three year response time is consistent with the lead time on new construction.

- The "Delayed Supplier Reaction" scenario, suppliers do not build any capacity that is not currently in PJM's queue until 2014. The market becomes very short on capacity, raising capacity prices. Moreover, suppliers do not react to the introduction of DR because they have no new capacity to delay, and the acceleration of retirements is unlikely in a scarcity situation. Hence, short-term price impacts last through 2013. This scenario reflects the possibility that suppliers are reluctant to build new generation in the current uncertain environment regarding re-regulation, fuel prices,
climate change, siting difficulties, and the rapidly escalating costs of new plant.

Finally, each supplier reaction scenario is analyzed assuming high rates of customer participation in dynamic pricing programs and, alternatively, low customer participation rates. Customer participation rates depend primarily on whether dynamic pricing becomes the default rate structure or merely an option that customers can elect. In the "CPP Default Rate Structure" scenario, 100% of customers would be enrolled in a critical peak pricing rate initially, and some 20% would eventually switch to a non-CPP rate structure, leaving 80% participation in year two and beyond. In the "CPP Elective" scenario, 0% of customers would sign up initially, ramping up to 20% in two years and beyond. (These rates are based on the experience from the California Statewide Pricing Pilot and other pilots.)

3) Conclusions Regarding Customer Benefits from Load Reductions

Figure 7 shows the benefits to all customers located within the Pepco DC zone if AMI is implemented in the District of Columbia according to PHI's proposed deployment schedule.

* Immediate response: short-term benefits last for 1 year; Slower response: short-term benefits last for 3 years;
** Delayed response: no generic entry and short-term benefits last until 2015.
*** Excluding additional potential real-time benefits.
**** A FPL-wide implementation of AMI and energy efficiency would increase reserve margins in Eastern MAAC from 18.1% to 18.5% in 2010, and from 11.3% to 12.3% in 2013 with CPP as the default rate structure, and from 18.1% to 18.6% in 2010, and from 11.3% to 12.3% in 2013 with CPP as a voluntary rate structure.

The following insights can be drawn from this analysis:
Overall, avoided capacity and energy benefits (i.e. buying less quantity) dominate the Net Present Value (NPV) in every scenario because of the longevity of these benefits relative to short-term price impacts.

Customer benefits are greatest if dynamic pricing is the default rate structure.

Customer benefits would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM, but they would be much greater in a scarcity situation in which generation supply is static until 2014 (except for projects already in PJM’s queue). If such scarcity were realized, having AMI in place would enable the Commission to substantially mitigate customer costs by making dynamic pricing the default rate structure.

Short-term savings to all customers, including those outside of the District of Columbia, would be much larger because Pepco’s load reductions would have a PJM market-wide impact on energy and capacity prices.

The customer savings to District of Columbia customers would be nearly twice as large as if all utilities in PJM-East followed Pepco’s lead in deploying DSM programs and achieved similar load reductions. The aggregate load reductions would create a much greater, market-wide short-term price impact.

In the scenario in which CPP is the default rate structure and suppliers build no new capacity until 2014 (other than projects in advanced stages currently in the PJM Generation Queue), PHI-wide implementation of its proposed DSM programs would increase reserve margins in Southwestern MAAC from 15.2 percent to 16.5 percent in 2010, and from 5.8 percent to 9.9 percent in 2013; in Eastern MAAC from 18.1 percent to 18.9 percent in 2010 and from 11.5 percent to 12.9 percent in 2013. Thus, PHI’s DSM initiatives would provide substantial value as insurance against intolerably low reserve margins.

The Brattle Group’s estimated savings from load reductions associated with AMI do not include potential additional customer benefits from reducing transmission losses, improving reliability, reducing rate volatility, enhancing market competitiveness, environmental benefits (through AMI-based information promoting efficiency), or potentially...
obviating or delaying the need for investments in transmission and distribution. These categories of benefits have not been quantified because the economic methodologies involved are not as well developed or standardized. Therefore, the total customer benefits of AMI could be substantially larger than the limited set of benefits reported in this Business Case.

Additional Benefits

Customer Benefits

Pepco uses a market research model developed by Market Strategies Inc ("MSI") to assist the company in identifying the key drivers of customer satisfaction. The energy delivery benefits associated with AMI related to billing, customer service, energy information and reliability contribute positively to Pepco's customer satisfaction performance once the full Blueprint plan is implemented. Additional customer benefits include:

- Improved website capabilities which will provide interval usage data to enable customers to understand when and how they are consuming energy at their homes and businesses.

- Individual customer load profile data can be useful in enabling the utility to target specific conservation programs or messaging to those customers who would achieve the maximum benefit. Pepco's "My Account" software has the capability to provide "Energy Grams" to customers which would offer customized energy conservation information based on how they are currently using energy.

- AMI would enable Pepco to provide for a "point of purchase" notification or understanding by consumers. Pepco's "My Account" software has the capability of providing AMI metered customers with "My bill to date" which enables customers to see how much they have spent so far in any given month. The "My bill to date" feature also enables the utility to perform outbound notifications to customers letting them know when energy consumption or spending has reached customer prescribed levels. These notifications will raise awareness of energy use and contribute to changing consumer behavior towards conservation and environmental stewardship.

- AMI allows Pepco to potentially offer "On-Request" meter reading services whereby a customer could request a specific meter reading
which would show consumption information for a period of time (1 hour for example). This type of reading would be able to let customers see a "before and after" view of energy use which enables them to see the benefits of conservation.

- **AMI will enable Pepco to provide on-line assistance with rate evaluations.** Customers would benefit from having an Interactive Rate Comparison program available on line to examine the cost savings potential of various rate options in a manner which is customized based on their actual historic load profile. Users would select among options and calculate the energy costs for each option automatically. Users could then print out a summary of the analysis to be used for making rate decisions.

- **AMI provides improved customer service due to the ability to remotely verify or determine that a particular meter is currently in service or out of service.** This helps to alert the customer that the problem may be on the customer side of the meter.

- **With AMI, it would be possible to offer customers an option of changing their monthly billing due date.** This could conceivably provide some cash flow and payment flexibility benefit for customers.

- **AMI information will benefit our Customer Contact Centers by enabling Customer Service Representatives ("CSR's") to quickly identify the time of high customer usage.** This would enable the CSR to offer enhanced levels of customer educations by explaining exactly when periods of high usage are occurring at the customer's home or business.

- **AMI allows the Company to be less intrusive to customers by not having meter reading personnel in or near the customer's home or business.**

**Theft of Service**

Pepco expects to improve the detection of lost revenue due to energy theft and other metering issues and to ultimately reduce it by using the capabilities of the AMI system. The AMI system is expected to enhance Pepco's ability to identify and recover lost revenue in three ways. First, by visiting all of Pepco's meter locations during the initial AMI meter deployment, Pepco anticipates that some percentage of the meters
Currently affected by tampering, diversion or other problem will be found and remedied.

Second, once the AMI system is installed, Pepco anticipates that additional data will be available to indicate the status of the meter as well as provide electronic notification of possible tampering. This functionality will permit more timely identification, investigation and remediation of possible theft events.

Finally, by using the interval data from the AMI system coupled with the analytical capabilities provided by the MDMS, Pepco expects to develop the capability to analyze usage and other patterns to discern possible theft cases, particularly with commercial accounts. According to the Edison Electric Institute (EEI), electric utilities typically estimate approximately one to three percent of their annual revenue is lost due to energy theft. If the expected AMI capabilities enable Pepco to improve its energy theft recovery by 0.5% of its annual kilowatt hour sales, the Company estimates that the recovered volume would be about 35 million kilowatt hours or about $4.1 million per year; assuming a combined residential distribution and standard offer service rate of 11.8 cents per kilowatt hour. Customers might experience a small reduction in rates due to reduced losses from the electrical system as the costs of the diverted electricity are paid for by the actual responsible parties. This benefit, however, would represent a shift in cost responsibility among customers, rather than a reduction in total revenue requirement recovered from all customers and was not included in this analysis.

Costs to Deploy

This section of the report provides the initial cost estimates for the deployment of the AMI system and the associated meter data management system ("MDMS") by Pepco’s delivery businesses. The costs will change as the Company conducts the procurement phase of its AMI project and evaluates the capabilities of the various AMI systems available in the market today. In addition, the quantifications will also change due to changing labor rates, payroll loading rates, inflation and other possible changes in the underlying assumptions used to derive the estimated cost values. Below is Figure 8 summarizing total capital expenditures needed for the initial deployment of the AMI system and annualized O&M costs expected in the first full year after deployment, followed by a more detailed description of each cost category.
1) Meters and Installation Labor

Costs include new AMI meters that contain certain equipment "under glass" such as remote connect/disconnect switch for certain meters, communications modules where applicable and the associated installation labor. Prices for AMI equipment are estimated using filings from other utilities as well as initial quotes from a few vendors and the calculated estimates consider differences in commercial and residential equipment requirements. A value of $85.00 is used for the AMI base cost for residential electric meters and a $194.00 value is used for commercial electric meters. Additionally 97% of residential electric meters will require a $25.00 remote connect/disconnect switch, which is not required for the commercial electric meter. Labor cost for installations is estimated at $165.00 per electric meter. This brings the estimated cost for meters with the associated installation labor to about $38 million for Pepco's electric customers in the District of Columbia.
2) Communications Network Infrastructure and Installation Labor

The communications network infrastructure solution is assumed to leverage Pepco’s existing network. The cost of this component of the AMI system is more variable than the other components (i.e., meters and the network management IT system), given the different ways AMI vendors configure and price their communications networks combined with the variability of terrain, meter density and meter locations in the District of Columbia. For purposes of this cost estimate, $70.00 per electric meter, including installation costs, was used. The total estimated costs for communications network infrastructure and the associated installation is about $18 million for Pepco’s electric customers in the District of Columbia.

3) AMI Network Management System and Meter Data Management System

This cost category captures the estimated costs associated with software applications, systems integration and computer hardware necessary to support AMI. System costs include categories for

- MDMS – software license, servers, storage, operating system, database management system, clustering software, and system design, configuration and integration
- Customer Presentment – servers, storage, and system design, configuration and integration
- PHI Integration – GIS and other IT systems integration.

The total estimated costs for the AMI Network Management System and the Meter Data Management System are about $4 million for Pepco’s customers in the District of Columbia.

4) Contingency

Pepco has determined that a contingency should be applied to the start-up and installation activities as a way to help manage the current uncertainty around the AMI cost estimate. A contingency amount comprising 6% of the capital investment for Pepco, representing an amount of about $3 million is included to cover unexpected increases in equipment costs, labor costs or materials prices.
5 and 6) MDMS Software Maintenance, License Fees and Hardware Leasing

The MDMS will require software maintenance and license fee contracts with the system’s vendor for system support, upgrades and the like. The operating costs for the hardware for the MDMS system include the hardware leasing costs for the servers, the data warehouse system and data storage capacity.

7) AMI Network Management IT System O&M

The AMI Network Management IT System has costs similar in nature to the MDMS with regard to software and hardware. Three additional FTEs are estimated to be required after AMI deployment to operate and maintain the AMI system for PHI.

8) Communication Network Infrastructure O&M

These costs include the estimated ongoing maintenance of the communications equipment needed to transmit the data back and forth between the meters on the customers’ premises and the Company’s offices. This cost is dependent on the mix of communication technologies Pepco ultimately obtains through its procurement process.

9) Labor Related Costs

The reduction in certain types of work would be phased in after the 2011 deployment, with labor related costs being incurred over a two year period (2011 and 2012). These costs would include reassignment and retraining of Pepco employees. The estimated cost of this one time expense is $1.2 million for the electric service.

Accelerated Depreciation

As stated in PHI’s April 4, 2007 Blueprint for the Future filing and in the 2007 NARUC Resolution to Remove Barriers to the Broad Implementation of Advanced Metering Infrastructure, the deployment of AMI technology will require the removal and disposition of existing meters that are not fully depreciated and the replacement of, or significant modification to, existing meter reading, communications, and customer

See NARUC Resolution Attached in Appendix 2
billing and information infrastructure. To encourage the implementation of this new technology the Commission should adopt ratemaking policies that remove a utility's disincentive toward demand-side resources that reduce throughput; provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and provide depreciation lives for AMI that take into account the speed and nature of change in metering technology.

The business case reflects depreciation lives for AMI that take into the account the speed and nature of the change in metering technology. The business case reflects a recovery period of fifteen years for the AMI investment and five years for the recovery of the remaining costs associated with the existing metering system. As of December 31, 2006, Pepco's existing electric metering system had a remaining net book value of about $44 million. Depreciation calculations in the business case may need to be updated due to pending federal legislation.

Developments in other jurisdictions

Congress with the passage of the Energy Policy Act of 2005 recognized the importance of advanced metering for growth in the development of electric demand response programs across the United States. To advance the development of such programs, Congress directed the Federal Energy Regulatory Commission ("FERC") to assess demand response resources currently in existence in the electric power industry. FERC conducted a survey where they requested information from every state on the number and uses of advanced metering, existing demand response and time-based rate programs within their state. As a result of this survey, states were required to consider the adoption of a smart metering standard for each of their state regulated utilities.

Many states took the FERC survey results and determined methods for confronting the rising energy costs within their particular states with Advanced Metering Infrastructure and Demand Response Programs. The following identifies several utilities which have obtained approval from their individual state regulatory commissions and are beginning implementation of intelligent meter technology, demand response and time-based rate programs within their operating jurisdictions. California and Texas utility companies have led the way in implementation of AMI and Demand Response Programs.
The California Public Utilities Commission ("CPUC") in 2004, directed each of the state's regulated utilities to explore the option and feasibility of upgrading their home and small-business electric meters to digital intelligent meters, similar to the types used to measure energy usage by larger commercial customers. The CPUC's goal was for its state regulated utilities to significantly ease California's constrained energy resources by providing some form of demand response during periods of peak demand. The need for a smart metering standard was essential in California due to the increased growth in population and per-person energy use in the state. California's state energy policies require utilities to commit large amounts of resources to fund and implement energy efficiency programs.

Pacific Gas & Electric ("PG&E")

Pacific Gas & Electric in 2008 obtained approval from the CPUC for the universal deployment of an AMI system which required the installation of 5.2 million electric meters and 4.1 million gas meters throughout its operating territory. PG&E immediately began an AMI pilot program in Bakersfield, California to test the accuracy and performance of SmartMeter™ after winning approval from the CPUC. Mass deployment of PG&E's SmartMeter™ Program is expected to begin in late 2007.

Southern California Edison (SCE)

Southern California Edison obtained approval from the CPUC to replace its existing 5.1 million electric meters with "next generation" electronic intelligent meter technology beginning in 2009. Edison SmartConnect™ is Southern California Edison's AMI Program which aims to improve overall customer service by allowing customers to proactively manage their energy use and also save money through participation in programs with time-differentiated rates and demand response options. The Edison SmartConnect™ program is the first overhaul of SCE's metering system since 1949.

San Diego Gas & Electric ("SDG&E")

San Diego Gas & Electric obtained approval from the CPUC in April 2007 to begin implementation of "smart meter" technology for its estimated 1.4 million electric meters and retrofitting approximately 900,000 gas meters throughout its service territory beginning in 2008. SDG&E's approval also
includes an agreement with the CPUC's Division of Ratepayer Advocates ("DRA") and the Utility Consumers' Action Network ("UCAN") to become a leader in emerging energy technologies through the use of a smarter electric distribution grid.

TEXAS

With the passage of House Bill 2129, the Texas Public Utility Commission was required to study the benefit to be derived by electric utilities in Texas from advanced metering. Because of the retail choice environment of the Texas retail market, the challenge exists for implementing advanced metering in a way that will maximize the benefits for the utility company, retail providers and customers. The Texas Commission has also initiated a separate project to evaluate potential demand response programs for the Texas utilities market.

Centerpoint Energy

Centerpoint obtained approval from the Texas Public Utility Commission in 2006 for implementation of smart meter technology for its more than three million electric and natural gas customers in the Houston area. Implementation of smart electricity meters began in November 2006 in selected areas of Houston.

TXU Electric Delivery

TXU Electric Delivery plans to have its 3 million automated meters by 2011, complementing an advanced grid intelligent enough to monitor electric service real-time. By year’s end, TXU Electric Delivery expects to have 370,000 automated meters system-wide, including 10,000 BPL-enabled meters. The BPL-enabled network will serve approximately 2 million residential and commercial customers in Texas.

OTHER JURISDICTIONS

Several utility companies in other jurisdictions have either filed applications or have obtained approval for implementing advanced metering and demand response programs. A sampling of these utilities companies are outlined below.

- Detroit Edison ("DTE") – The Michigan Commission approved DTE’s plan to replace 3 million electric meters. DTE is investing $330 million for implementation of this over the next six years. DTE has also
created a Home Energy Saver audit tool on their website (mydtenergy.com) to help customers manage their energy use and obtain conservation tips.

- Pennsylvania Power & Light Company ("PPL") – PPL completed the installation of 1.3 million electric meters in 2004. PPL has created sections on its website dedicated to energy conservation efforts, including an energy calculator, detailed information about smart meters, safety concerns and an energy library for customers to learn more about energy usage in their homes.

- Baltimore Gas & Electric Company ("BGE") – BGE filed for approval by the Maryland Public Service Commission in early 2007 of its plan to deploy an AMI system and Demand Side Management Programs.

- Southern Company – Southern Company obtained Commission approval to replace 4.5 million electric meters in their four-state operating territory.

- Portland General Electric ("PGE") – PGE has filed an application with the Public Utility Commission of Oregon to install 843,000 smart meters for both residential and small non-residential customers throughout PGE's operating territory.
Business Case Summaries from Other Utilities

Summaries based on publicly available information from filings for PG&E, Southern California Edison and San Diego Gas and Electric are included below. The summaries demonstrate the similarities in approach and results with PHI's AMI business case analysis.

Pacific Gas and Electric Company

The AMI business case filed by PG&E with the California Public Utilities Commission shows that AMI can largely be justified by the operational benefits and savings to the utility. The operational "gap" between the costs and benefits for a full AMI deployment case is $234 million on a present value revenue requirement (PVRR) basis. Adopting a benefit calculation* for Demand Response of $338 million which is more conservative than a Base Case* of $510 million still results in finding that the project is cost-effective.

The field and metering services benefits include the reduction/elimination of the labor and non-labor costs required for regular meter reading and change of party/special reads and remote Turn-On/ Shut-Off. Other operational benefits include Improvement in Electric & Gas Transmission and Distribution restoration after significant outages, reduced customer calls and duration of calls related to billing and power outages, and reduced employee-related costs.

The major categories of deployment costs for AMI include meter and module equipment and installation costs, network equipment and install costs, and IT costs that include interval billing system, interface and integration costs. Operational and maintenance costs include AMI
operation costs, meter operation costs, marketing and communications costs, and customer acquisition costs

Southern California Edison

The AMI business case filed by SCE with the California Public Utilities Commission shows that AMI is justified by the Operational, Load Control, and Price Response Benefits to the utility. The operational “gap” between the costs and benefits for a full AMI deployment case is $356 million on a present value revenue requirement (PVRR) basis. The new functionality of the Edison SmartConnect™ technology not only increases the ways in which customers can use demand response; it also results in SCE going from a negative $951 million Present Value Revenue Requirement (PVRR) in 2005,\textsuperscript{12} to a positive $109 million PVRR in 2007 for full AMI deployment.

Through its AMI System Design and Use Case Process, SCE will integrate Edison SmartConnect™ into its operating systems to ensure that the expected benefits accrue in the areas of customer service, billing, outage management, and operations and maintenance.

Operational savings are forecast to cover approximately 63 percent of the related costs. Participation by residential and <200kW business customers in dynamic pricing and demand response programs is expected to provide sufficient additional benefits to justify the Edison SmartConnect™ project. The cost-benefit analysis is summarized in the Figure below.

\textsuperscript{12} Source: EDISON SMARTCONNECT™ DEPLOYMENT FUNDING AND COST RECOVERY
Volume 1 – Policy July 31, 2007 - Before the Public Utilities Commission of the State of California
Appendix 2 NARUC Resolution
Resolution to Remove Regulatory Barriers To the Broad Implementation of Advanced Metering Infrastructure

WHEREAS, The Energy Policy Act of 2005 amended the State ratemaking provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA) to require every State regulatory commission to consider and determine whether to adopt a new standard with regard to advanced metering infrastructure (AMI); and

WHEREAS, Advanced metering, as defined by Federal Energy Regulatory Commission (FERC), refers to a metering system that records customer consumption hourly or more frequently and that provides daily or more frequent transmission of measurements over a communication network to a central collection point; and

WHEREAS, The implementation of dynamic pricing, which is facilitated by AML, can afford consumers the opportunity to better manage their energy consumption and electricity costs through the practice of demand response strategies; and

WHEREAS, Effective price-responsive demand requires not only deployment of AML to a material portion of a utility’s load, but also implementation of dynamic price structures that reveal to consumers the value of controlling their consumption at specific times: and

WHEREAS, AML deployment offers numerous potential benefits to consumers, both participants and non-participants, including:
- greater customer control over consumption and electric bills;
- improved metering accuracy and customer service;
- potential for reduced prices during peak periods for all consumers;
- reduced price volatility;
- reduced outage duration; and,
- expedited service initiation and restoration; and

WHEREAS, The use of AML may afford significant utility operational cost savings and other benefits, including:
- automation of meter reading;
- outage detection;
- remote connection/disconnection;
- reduced energy theft;
- improved outage restoration;
- improved load research;
- more optimal transformer sizing;
- reduced demand during times of system stress;
- decreased T&D system congestion; and,
- reduced reliance on inefficient peaking generators; and

PAGE 40
WHEREAS, Sound AMI planning and deployment requires the identification and consideration of tangible and intangible costs and benefits to a utility system and its customers; and

WHEREAS, Cost-effective AMI may be a critical component of the intelligent grid of the future that will provide many benefits to utilities and consumers; and

WHEREAS, It is important that AMI allow the free and unimpeded flow and exchange of data and communications to empower the greatest range of technology and customer options to be deployed; and

WHEREAS, The deployment of cost-effective AMI technology may require the removal and disposition of existing meters that are not fully depreciated and may require replacement of, or significant modification to, existing meter reading, communications, and customer billing and information infrastructure; and

WHEREAS, Regulated utilities may be discouraged from pursuing demand response opportunities by the prospect of diminished sales and revenues; now, therefore, be it

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its February 2007 Winter Meetings in Washington, D.C., recommends that commissions seeking to facilitate deployment of cost-effective AMI technologies consider the following regulatory options:

- pursue an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits;
- adopt ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources;
- provide for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment; and,
- provide depreciation lives for AMI that take into account the speed and nature of change in metering technology; and be it further

RESOLVED, That the Federal tax code with regard to depreciable lives for AMI investments should be amended to reflect the speed and nature of change in metering technology; and be it further

RESOLVED, That NARUC supports movement toward an appropriate level of open architecture and interoperability of AMI to enable cost-effective investments, avoid obsolescence, and increase innovations in technology products.

Sponsored by the Committee on Energy Resources and Environment
Adopted by NARUC Board of Directors February 21, 2007
<table>
<thead>
<tr>
<th>Type of Service</th>
<th>Description</th>
<th>Benefit Code</th>
<th>Financial Category</th>
<th>Benefit Code</th>
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<tr>
<td>Asset Optimization</td>
<td>03M-3 Improve Billing Accuracy 0M1-6</td>
<td>03M-3 Improve Billing Accuracy 0M1-6</td>
<td>03M-3 Improve Billing Accuracy 0M1-6</td>
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<tr>
<td></td>
<td>0M1-6 Implement Routine Data Collection System 0M1-6</td>
<td>0M1-6 Implement Routine Data Collection System 0M1-6</td>
<td>0M1-6 Implement Routine Data Collection System 0M1-6</td>
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</table>

**Total:**

- Asset Optimization
- Implement Remote Turn-on/Turn-off Functionality
- Improve Billing Activity
- Eliminate Handheld Data Collection System

**Description - Benefits:**

- Eliminate Time/Wraps, Schedules, Maintenance and Operations Cost for the Reducer Off-Cycle Meter Reading
- Eliminate Manual Meter Reading Costs
- Improve Compliant Handling

**Type of Service:**

- Power Delivery

**Summary of Analyzed Benefits by Company/Function/Type of Service:**

**PHI Power Delivery**

**Operating Company:**

**Summary of Analyzed Benefits by Company/Function/Type of Service:**

**PHI Power Delivery**

**Type of Service:**

- Power Delivery

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**Summary of Analyzed Benefits by Company/Function/Type of Service:**

**PHI Power Delivery**

**Type of Service:**

- Power Delivery
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<tr>
<th>Description</th>
<th>Quantity</th>
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<tr>
<td>Hydrocarbon Concentration Plant</td>
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<tr>
<td>Petroleum Plant</td>
<td>1</td>
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<tr>
<td>Chemical Plant</td>
<td>1</td>
</tr>
<tr>
<td>Other Plant</td>
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</table>

**TOTAL:** 4 plants

---

**Notes:**
- All plants are located in the United States.
- The plants operate 24 hours a day, 7 days a week.
- Each plant has a capacity of 1,000,000 barrels of crude oil per day.
- The plants are owned by XYZ Corporation.
### Financial Cash Flow Statement

**Project Name:**[line]
**Analysis Period Start Month:**[line]
**Analysis Period Start Year:**[line]
**Analysis Period in Years:**[line]

<table>
<thead>
<tr>
<th>Cost Code</th>
<th>Description</th>
<th>Related Cost</th>
<th>Financial Category</th>
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<tbody>
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**SUMMARY**

### Proposed and Proposed Calculation Related to Benefits MB-2

**MB-2 O&M**

Total amount of reassessment/retraining costs expected for the 16 special readers in 2011 based on projected years of service, 2 weeks per year and the existing salary evaluated at 3% per year out to 2011 from 2007’s estimated.

<table>
<thead>
<tr>
<th>Allocation to DC and MD Based on 2007 Average Customers</th>
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</thead>
<tbody>
<tr>
<td><strong>Pepco-DC</strong></td>
</tr>
<tr>
<td><strong>Pepco-MD</strong></td>
</tr>
<tr>
<td><strong>Combined Pepco</strong></td>
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</table>

### Proposed Credit & Collections

<table>
<thead>
<tr>
<th>Sum of Estimated Reassessment/Retraining Cost</th>
<th>Total</th>
<th>2006 Actual Credit Disbursements / RIB Volume</th>
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<tbody>
<tr>
<td>Call Order Dispatcher</td>
<td>$ 61,648.24</td>
<td>DC 426,000.00</td>
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<tr>
<td>Collection Specialist</td>
<td>$ 1,261,064.80</td>
<td>MD 426,000.00</td>
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<tr>
<td>Collection Specialist A</td>
<td>$ 210,499.52</td>
<td>Total Pepco 852,000.00</td>
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<tr>
<td>Collector</td>
<td>$ 156,765.06</td>
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<tr>
<td>Supervisor</td>
<td>$ 17,940.00</td>
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<tr>
<td>Grand Total</td>
<td>$ 1,821,004.62</td>
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</table>

<table>
<thead>
<tr>
<th>DC</th>
<th>MD</th>
<th>Total Pepco</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 1,261,064.80</td>
<td>$ 210,499.52</td>
<td>$ 1,471,564.32</td>
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</table>
### Calculation of expected reassignment/retraining cost for Pepco

<table>
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<tr>
<th>Assumptions:</th>
<th>Current Average Headcount</th>
<th>Average Salary</th>
<th>Average Weekly Salary</th>
<th>Current Average Yrs of Service</th>
<th>Average Yrs of Service</th>
<th>Weeks of Pay Eligibility</th>
<th>Estimated Reassignment/Retraining Cost</th>
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<tr>
<td>2 Supervisor in 2012</td>
<td>2 $73,748 $</td>
<td>$135,898.13</td>
<td>$1,695.121</td>
<td>27</td>
<td>31</td>
<td>62</td>
<td>$203,871</td>
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<tr>
<td>8 Revenue Analyst A in 2012</td>
<td>8 $73,038 $</td>
<td>$130,708.15</td>
<td>$1,695.461</td>
<td>6</td>
<td>9</td>
<td>18</td>
<td>$129,088</td>
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<td>18 Revenue Analyst B in 2012</td>
<td>18 $42,060 $</td>
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<td>$1,611.661</td>
<td>71</td>
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<td>$376,764</td>
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Allocation based on 2007 budgeted customer counts:

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<th>2012</th>
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<tbody>
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<td>Pepco-DC</td>
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<tr>
<td>Pepco-MD</td>
<td>516,720</td>
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<td>Combined</td>
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</table>
### PHI Power Delivery

**Summary of Reassessment and Retraining Costs**

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<th>Benefit Code</th>
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<td><strong>YEAR = 2010</strong></td>
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<tr>
<td>Improve Complain Handling</td>
<td>CB-2</td>
<td>O&amp;M</td>
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<tr>
<td>Reduce Off-Cycle Meter Reading Labor Costs</td>
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<td>O&amp;M</td>
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<tr>
<td>Improve Billing Activities</td>
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<td>O&amp;M</td>
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<td>Implement Remote Turn-on/Turn-off Functionality</td>
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<td>O&amp;M</td>
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<tr>
<td><strong>TOTAL FOR 2010</strong></td>
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<tr>
<td><strong>YEAR = 2011</strong></td>
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Page 14 of 14
THE
BRATTLE REPORT
Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI’s Proposed Demand-Side Management Programs

Prepared by

The Brattle Group
44 Brattle Street
Cambridge, MA 02138

Prepared for

Pepco Holdings, Inc.

September 21, 2007
1.0 Executive Summary
2.0 Organization of This Report
3.0 Overview of Methodology
3.1.1 Scope of DSM Implementation and Benefits
3.1.2 Time
3.1.3 Scenario Definition
3.2 Estimation of Load Reductions Over Time
3.3 Estimation of Customer Benefits
3.3.1 Resource Cost Savings (Buying Less Quantity)
3.3.2 Short-Term Market Price Impacts (Buying at Lower Prices)
4.0 Forecasting PHI's Peak Demand Reductions Due to Dynamic Pricing
4.1 Overview
4.2 Description of PRISM
4.2.1 The Representative Dynamic Rate
4.2.2 Residential Load Shapes
4.2.3 Commercial and Industrial Customers' Load Shapes
4.2.4 Existing All-In Rates
4.2.5 Saturation of Central Air Conditioners
4.2.6 Temperature Statistics
4.3 Customer-Level Impacts
4.4 Forecasting Customer Participation
4.4.1 Customers Eligible for AMI
4.4.2 AMI Deployment Schedule
4.4.3 Customer Participation in Direct Load Control
4.4.4 Enrollment Rate
4.5 System-Wide Peak Demand Impacts of Dynamic Pricing
5.0 Resource Cost Savings
5.1 Capacity Savings
5.1.1 Theory
5.1.2 Methodology
5.1.3 Results
5.2 Generation Savings
5.2.1 Theory
5.2.2 Methodology
5.2.3 Results
5.3 Ancillary Services Benefits
6.0 Short-Term Energy Price Impacts
6.1 Theory
6.2 Methodology
6.3 Results
6.4 Real-Time Premium
7.0 Short-Term Capacity Price Impacts
7.1 Theory
7.2 Methodology
7.3 Results
8.0 Other Benefits that have Not Been Quantified
8.1 Reliability Benefits
8.2 Market Competitiveness Benefits
8.3 Insurance Benefits / Reducing Rate Volatility
8.4 Transmission and Distribution Loss Benefits
8.5 Transmission and Distribution Investment Benefits
8.6 Environmental Considerations
8.7 Non-Critical Periods
9.0 Net Present Value of Benefits
1.0 EXECUTIVE SUMMARY

The Brattle Group has been retained by Pepco Holdings, Inc. (PHI) to estimate customer benefits from reductions in peak loads during critical times that are likely to be achieved by PHI's proposed demand-side management (DSM) initiatives in all of its Delaware, District of Columbia, Maryland and New Jersey jurisdictions. This whitepaper describes the methodology and conclusions from Brattle's analysis, which involves two major components: first, determining the magnitude of load reductions that are likely to be achieved by PHI's proposed DSM initiatives, as outlined in its Blueprint for the Future; and second, estimating the customer value of such load reductions. PHI's Blueprint proposes programs in energy efficiency and direct load control, and announces its planned deployment of an advanced metering infrastructure (AMI), which will enable direct load control and dynamic pricing. This study estimates the customer benefits from peak load reductions resulting from all of these measures, which are collectively referred to in this report as "DSM."

Reductions in critical peak loads (top 60 hours) are estimated as follows: load reductions from energy efficiency and direct load control are provided by PHI, consistent with the Blueprints. (The sub-components of the energy efficiency and direct load control programs are shown in Figure A.1 in the Appendix.) Load reductions associated with AMI-enabled dynamic pricing programs are estimated using the Pricing Impact Simulation Model (PRISM) model, which is based on empirical data from the California Statewide Pricing Pilot and is calibrated to the load, rate, air conditioning and weather characteristics of residential and small commercial and industrial (C&I) customers in each of PHI's jurisdictions.

Two alternative dynamic pricing scenarios are analyzed, both based on the dynamic rates designed for the District of Columbia smart metering pilot program. In one scenario, customers can voluntarily elect to enroll in a CPP rate structure, resulting in 20 percent of eligible customers participating. In the alternative scenario, CPP is the default (but not mandatory) rate structure, resulting on 80 percent of eligible customers participating. As shown in Figure 1.1, the combined peak load reductions from all of PHI's proposed DSM programs would likely be quite substantial when full deployment of AMI is reached by 2013.

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1 PHI is selling its Virginia electric distribution service territory.
2 Delaware Public Service Commission, Docket # 07-28, filed on February 6, 2007; Maryland Public Service Commission ML#106885 filed on July 23, 2007.
3 PowerCentsDC is the smart metering pilot program in the District of Columbia managed by the Smart Meter Pilot Program, Inc. (SMPP). Board members of SMPP include representatives of Pepco, the District of Columbia Office of People's Council, the District of Columbia Commission, the District of Columbia Consumers Utility Board, and the International Brotherhood of Electrical Workers. The pilot is testing three alternative dynamic electricity rates: Critical Peak Pricing, Hourly Pricing, and Critical Peak Rebate. Pricing adjustments are made based upon day ahead PJM sub Zonal PJM hourly market prices.
4 Eligible customers are assumed to include all residential and small commercial industrial customers that do not already have an interval meter. AMI is expected to provide hourly load data to the utility on a daily basis.
Reducing peak load benefits customers in several ways, including: (1) providing “resource cost savings” by reducing the quantity of capacity, energy, and ancillary services that customers must buy (or enabling them to sell those products); (2) creating “short-term market price impacts,” i.e., depressing wholesale market prices for energy and capacity; (3) improving reliability; (4) enhancing market competitiveness; (5) reducing rate volatility; (6) reducing transmission distribution losses; and (7) potentially obviating or delaying the need for investments in transmission and distribution.

This analysis estimates the customer savings that PHI’s proposed DSM programs are likely to achieve by lowering resource costs and, separately, by temporarily reducing market prices. The applied methodology is consistent with The Brattle Group’s January, 2007 study, Quantifying Demand Response Benefits in PJM, sponsored by PJM the Mid-Atlantic Distributed Resources Initiative (MADRI), and the public utility commissions in Delaware, The District of Columbia, Maryland, New Jersey, and Pennsylvania. However, the present study includes several enhancements, most notably the estimation of capacity price impacts and a scenario analysis addressing the longevity of “short-term price impacts.” The other categories of benefits (numbers 3-7 listed above) are discussed qualitatively but have not been quantified because the economic methodologies involved are not as well developed or standardized, nor could they be analyzed within the scope of this analysis. The study scope also excludes changes in consumption during the non-critical-peak hours because the energy price effects during those hours are less pronounced and capacity effects are non-existent, even if the impact on total
generation and emissions are significant (e.g., due to improved equipment efficiencies or improved energy management based on AMI-enabled information regarding customers’ energy usage patterns). Therefore, the total benefits of PHI’s proposed programs could be substantially larger than the benefit estimates reported here.

A key insight affecting the design of this study is that resource cost savings persist over time, but market price impacts can be expected to diminish as generation suppliers respond to depressed prices, for example, by delaying their construction of new generation or accelerating their retirement of existing plants. The magnitude and duration of the market price impact depends on the rate at which suppliers respond to changes in market conditions as well as on the tightness of the market over the next several years. Accordingly, this study quantifies customer benefits under a range of supply scenarios. Figure 1.2 shows the net present value of benefits to customers in all of PHI’s load zones (including municipal and cooperative utilities contained within the PHI load zones) if energy efficiency, direct load control, and dynamic pricing were implemented in all of PHI’s jurisdictions. The net present value assesses benefits, and not costs, through 2029, based on a 15-20 year life of equipment and programs, discounted at a rate equal to the after-tax weighted average cost of capital filed by PHI utilities.

Figure 1.2. Net Present Value of Quantified Customer Benefits in all PHI Zones through 2029 (Millions of 2007 Dollars)
The following insights can be drawn from this analysis:

- Overall, avoided capacity and energy benefits (i.e. buying less quantity) dominate the Net Present Value (NPV) in every scenario because of the longevity of these benefits relative to short-term price impacts.
- Customer benefits are greatest if dynamic pricing is the default rate structure.
- Customer benefits would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of DSM, but they would be much greater in a scarcity situation in which generation supply is static until 2014 (except for projects already in PJM's queue). If such scarcity were realized, having AMI in place would enable the Commission to substantially mitigate customer costs by making dynamic pricing the default rate structure.
- Short-term savings to all customers, including those outside of PHI's zones, would be much larger because PHI's load reductions would have a PJM market-wide impact on energy and capacity prices. For example, the total benefits to all of PJM-East are five to eight times greater than the benefits to all customers in the PHI zones. (The PHI zones contain approximately 20 percent of the load in PJM-East.)
- The customer savings to PHI customers would be nearly twice as large as if all utilities in PJM-East followed PHI's lead in deploying DSM programs and achieved similar load reductions. The aggregate load reductions would create a much greater, market-wide short-term price impact.
- Although CPP programs typically designate peak periods on a day-ahead basis, making the programs callable on a real-time basis (instead of a day-ahead time frame) would enable customers to mitigate the impacts of real-time surprises in load or supply outages. This could add an additional $2 to $10 million in value, depending on the scenario.
- Although this analysis does not quantify the reliability benefit in financial terms, DSM's potential contribution to installed reserve margins has been estimated. In the scenario in which CPP is the default rate structure and suppliers build no new capacity until 2014 (other than projects in advanced stages currently in the PJM Generation Queue), PHI's DSM programs would increase reserve margins in Southwestern MAAC from 15.2 percent to 18.3 percent in 2010, and from 5.8 percent to 14.4 percent in 2013; in Eastern MAAC from 18.1 percent to 21 percent in 2010 and from 11.5 percent to 19.9 percent in 2013. Thus, PHI's DSM initiatives would provide substantial value as insurance against intolerably low reserve margins.

5 Day-of CPP programs were tested in the California pilot and were found to be feasible. In addition, Illinois has tested real-time pricing for residential customers and shown it be feasible and attractive to customers.
These estimates of customer benefits are likely to be conservative due to the limited scope of benefits quantified. Furthermore, the largest component of the estimated benefit, the avoided capacity costs, is probably understated because it is based on a historical Net Cost of New Entry that does not account for the recent dramatic worldwide upswing in the cost of all kinds of new generation. On the less conservative side, it is possible that the Inadequate Supply Response scenario exaggerates the looming supply shortage in Southwest and Eastern MAAC by assuming zero entry of capacity that is not yet planned until 2014. The scenario was constructed to demonstrate the potential value of DSM in a severely supply-constrained situation.

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It could be argued that even if private investors under-provide new capacity in that time period, they will still add some capacity, and the utilities could also build new capacity as a last resort.
2.0 ORGANIZATION OF THIS REPORT

Section 3 presents an overview of the study design, economic concepts, and analytical methodologies employed. Section 4 describes the assumptions, data, and methodology used to estimate peak load reductions from dynamic pricing (there is no similar discussion of the peak load reductions from energy efficiency and direct load control because those figures were provided directly by PHI and detailed in the Company's various Blueprint for the Future filings.) Sections 5 through 7 provide a detailed explanation of the analysis of customer benefits from all of PHI's proposed DSM programs: Section 5 addresses resource cost savings; Sections 6 and 7 address short-term energy and capacity price impacts, respectively. Section 8 discusses customer benefits that have not been quantified in this study.

Whereas the executive summary presents only the benefits to customers in PHI zones when all of PHI's DSM initiatives are implemented, Section 9 provides the benefits to the rest of the customers in each of the states, and also the potential benefits if all utilities in PJM-East followed PHI's lead and deployed programs achieving load reductions similar to those in PHI.

3.0 OVERVIEW OF METHODOLOGY

The analysis of benefits from PHI's proposed DSM initiatives involves two major components: first, determining the magnitude of likely peak load reductions; and second, estimating the value of such load reductions over time and under a range of market conditions.

3.1. STUDY DESIGN

Analyzing DSM benefits in multiple jurisdictions over time and over a range of plausible future market conditions required several study design choices regarding time, scenario definition, and the assumed scope of DSM implementation and benefits.

3.1.1. Scope of DSM Implementation and Benefits

Benefits are estimated for all customers in each PHI zone (separated by state where applicable), each state (all zones), and the entire PJM-East region, under three alternative assumptions regarding the scope of DSM implementation: in each PHI zone in isolation, in all PHI zones simultaneously, and in the entire PJM-East region. The body of this report focuses on the benefits to customers in the PHI zones resulting from PHI-wide implementation, Section 9 shows all combinations of implementation and beneficiary areas.

3.1.2. Time

The analysis of benefits focuses on critical peak hours in the summers of 2010 and 2013 then interpolates and extrapolates to 2009-2029 based on the relative amounts of peak load reductions
expected in each year. Market price benefits are assumed to diminish over time as suppliers delay new construction and accelerate retirements in response to reduced load and market prices (according to the three supplier response scenarios discussed below). The multi-year stream of benefits is translated into a net present value using the after-tax weighted average cost of capital for each of the PHI jurisdictions.

3.1.3. Scenario Definition

Scenarios were designed to span the range of plausible future market conditions. Scenarios differ in the factors that most affect the value of DSM: customer participation rates in the DSM programs and the activity of suppliers.

Customer Participation. Customer participation rates depend primarily on whether CPP becomes the default rate structure or merely an optional tariff. In the “CPP Default Rate Structure” scenario, 100 percent of customers would be enrolled initially and some 20 percent would eventually switch to a non-CPP rate structure, leaving 80 percent participation in year two and beyond. In the “CPP-Optional” scenario, no customers would sign up initially, ramping up to 20 percent in two years and beyond. These rates are based on the experience from the California Statewide Pricing Pilot and other pilots.

Supplier Responsiveness. The energy/capacity price impacts of DSM are larger and longer lasting in a scarcity situation than a surplus market or a balanced market in which suppliers react quickly to DSM’s successes (and price impacts) by delaying construction of new capacity or by accelerating the retirement of existing plants. A range of possible market conditions is explored using three supplier scenarios in which the longevity of price impacts is varied:

- In the “Immediate Supplier Reaction” scenario, the market is in supply-demand equilibrium, and suppliers react quickly to changes in fundamentals. Short-term energy price impacts (which are derived from the Brattle-PJM-MADRI study, which used a short-term equilibrium model in which supply was static), lasts for only one year before suppliers fully react. One year after the introduction of new DR, suppliers have accelerated enough retirements and/or delayed enough new construction to completely offset the price impact of DR. Hence, if PHI’s deployment schedule produces 200 MW or peak load reduction in year n and 300 MW in year n+1, only 100 MW of load reductions has a price impact in year n+1. This scenario is consistent with the observation that suppliers in the recent Reliability Pricing Model (RPM) Base Residual Auction quickly changed their plans by delaying retirements presumably in response to high Eastern prices in the prior auction.
- The “Slower Supplier Reaction” scenario is similar to the Immediate scenario except that short-term price impacts last for three-years before

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7 The same utility discount rates were used as in PHI’s AMI Business Case Reports for each PHI jurisdiction. These rates are stated in Section 9 of this report.
suppliers respond. The three year response time is consistent with the lead
time on new construction.9

In the “Delayed Supplier Reaction” scenario, suppliers do not build any
capacity that is not currently in PJM’s queue until 2014. The market
becomes very short on capacity, raising capacity prices. Moreover,
suppliers do not react to the introduction of DR because they have no new
capacity to delay, and the acceleration of retirements is unlikely in a
scarcity situation. Hence, short-term price impacts last through 2013.
This scenario reflects the possibility that suppliers are reluctant to build
new generation in the current uncertain environment regarding re-
regulation, fuel prices, climate change, siting difficulties, and the rapidly
escalating costs of new plant.10

Combinations. Each permutation of customer participation sales and supplier reaction rates is
considered for a total of six scenarios.

Other Market Conditions. Estimates of the benefits from energy market impacts and avoided
generation are based on the Brattle-PJM-MADRI study, which analyzed six scenarios
representing a broad range of weather and fuel price conditions: actual 2005 market conditions, a
weather-normalized case, a high peak load case, a low peak load case, a high fuel price case, and
a low fuel price case.11 The variation in customer benefits associated with each of these cases is
expressed as a range in the Appendix. In the summary tables within the body of this report, only
the average of the Low Peak and High Peak benefits is presented. Such an average is somewhat
higher than the benefits in the Normalized Load case because it captures the non-linear increase
in prices (and price sensitivity to DR) as market conditions become tighter.

3.2. ESTIMATION OF LOAD REDUCTIONS OVER TIME

PHI is proposing DSM programs involving energy efficiency, direct load control, and AMI,
which will enable dynamic pricing programs. In order to estimate likely load reductions from
AMI-enabled dynamic pricing programs, Brattle used the PRISM model. PRISM is based on
California’s Statewide Pricing Pilot, but it has been calibrated to PHI’s customer characteristics
and likely rate structure (based on the District of Columbia smart meter pilot program) and PHI’s
planned AMI deployment schedule, as discussed in Section 4.

PHI provided The Brattle Group with its estimates of likely peak load reductions resulting from
its proposed energy efficiency and direct load control programs. These estimates have been
adopted as-is without validation or modification by The Brattle Group. PHI’s estimated
reductions from energy efficiency, conservation, direct load control, and demand response

9 See FERC Order on Rehearing and Clarification and Accepting Compliance Filing, Docket No. ER05-1410-
10 See, for example, “Constellation, PPL See Gold in Tight Markets,” Megawatt Daily, September 6, 2007.
11 Because of the way the loads were constructed, the weather-normalized case and all of the scenarios other
than the actual 2005 scenario are representative of possible conditions for 2007 or 2008, not 2005.
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(excluding dynamic pricing) are contained within the Company’s Blueprint for the Future filings.

In combination, dynamic pricing, direct load control, and energy efficiency lower peak loads significantly, as shown in Figure 1.1. The combined load reduction is the starting point for the analysis of customer benefits, as described below.

3.3. ESTIMATION OF CUSTOMER BENEFITS

This study estimates two major categories of benefits: resource cost savings and, separately, short-term price impacts. (Other categories of benefits that have not been quantified are discussed in Section 8.0).

3.3.1. Resource Cost Savings (Buying Less Quantity)

With reduced peak loads, customers do not need to buy as much capacity; indeed less generation capacity must ultimately be built to serve a flatter load shape. Customers also do not need to buy as much energy during high-priced periods. Reducing the quantity of capacity and energy that must be produced saves money even if wholesale prices remain unchanged. This kind of savings is often considered a “resource cost savings” because the total cost to serve load is reduced. Customers save commensurately whether they are in a cost-of-service regulatory regime, or in a market-based regime, as in PHI’s footprint. Assuming a competitive wholesale market, suppliers can be expected to offer capacity and generation based on their costs to serve and to pass changes in their costs onto customers. If the wholesale market is not fully competitive, it is likely that savings would be even greater because DR enhances market competitiveness, as explained in Section 8.

Capacity savings are estimated by multiplying the projected reduction in physical capacity requirements by the $/MW value of physical capacity. The reduction in physical capacity requirements is estimated by assuming that all expected DR could either supply capacity or reduce the load forecast, thus avoiding the need for physical capacity to the extent that the simultaneous peak load forecast is reduced (multiplied by 1 plus the reserve margin). The value of capacity is given by the capacity price, which must be forecasted. In the “Immediate Supplier Reaction” and “Slower Supplier Reaction” scenarios, it is assumed that the market reaches an economic equilibrium by 2009, with capacity prices set by the net cost of new entry (Net CONE) used by PJM in its RPM. Net CONE is $51/kW–yr in Eastern MAAC and $54.5/kW–yr in Southwestern MAAC. However, in the “Delayed Supplier Reaction” scenario, the market is assumed to be in a scarcity situation until 2014. Capacity prices are assumed to be set by Net CONE in 2014 forward. Before then, prices are higher than Net CONE, given by the intersection of projected supply and demand curves, as described in Section 5.

Reducing demand also reduces the amount of energy that must be generated and purchased by customers (during high-priced periods). The economic savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not
constructed and old capacity retired or not dispatched. The savings is also partially offset by the value that the consumer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to assess and also depends on whether the customer shifts load to lower-priced periods. These issues were addressed in the Brattle-PJM-MADRI study, in which net generation savings amounted to an additional 12 to 36 percent on top of the capacity savings. The present study simply adopts these figures by scaling the net generation savings from the Brattle-PJM-MADRI study to the amount of load reduction.

Interruptible demand (e.g., that under direct load control) could also create value by providing ancillary services (A/S) – load reductions would have to be on call for 30-minute dispatch at short notice, much like generation resources providing A/S. However, A/S value is somewhat speculative because PJM’s inclusion of demand response in its A/S markets is in its infancy. Demand response (DR) currently provides some A/S in PJM and ISO-NE, including smaller customers (< 5 MW) on an experimental basis in ISO-NE. We assume conservatively that AMI could eventually enable 100 MW of spinning reserves from loads that can be curtailed for 30 minutes on a moment’s notice through direct load control. The contribution of DR to spinning reserves would provide the retailer and/or program participants with a source of revenue and would reduce the need for supply-side resources to provide spinning reserves, the marginal value of which is given by the market price for spinning reserves. Hence ancillary service value is estimated by multiplying a conservative quantity of spinning reserves by a historical average price of spinning reserves ($8.5/MWh during 2004-06) by the number of hours in a year.

3.3.2. Short-Term Market Price Impacts (Buying at Lower Prices)

Even a small reduction in demand during tight market conditions may lower the market price for energy. This lowers the price of energy for all customers, not just those curtailing load, and not just customers in the zone where DR is implemented, as shown in the Brattle-PJM-MADRI study. Similarly, reducing the peak demand lowers the demand for capacity, which can lower the market price for capacity, which affects all customers in the same locational delivery area (another positive externality) and more broadly throughout the PJM market.

Short-term energy price reductions are estimated by adapting the results of the Brattle-PJM-MADRI study to reflect the differences in load reductions expected from PHI’s DSM programs. To the extent that PHI’s load reductions differ from the load reductions simulated in the Brattle-PJM-MADRI study, price impacts are estimated using linear extrapolation (e.g., twice the MW of load reductions causes twice the price impact). This linear approach does not consider that the marginal price effect could diminish as load reductions increase; that effect could be quantified by performing new simulations tailored to PHI’s programs. However, performing new simulations would have required substantially more time and resources, and the increased precision would have been only minimally helpful given the uncertainties in market conditions, participation rates in dynamic pricing, and the unknown agility with which generation suppliers

ISO-NB’s Demand-Response Reserve Pilot Program is discussed in section 6.3 of ISO-NB’s 2007 Regional System Plan (third draft) dated August 30, 2007.
will react to the introduction of PHI's DSM initiatives. These uncertainties are handled through scenarios, which policy makers can weigh against each other.

As in the Brattle-PJM-MADRI study, the customer benefit from reduced energy prices can be estimated by multiplying the expected price reduction by the quantity of load exposed to market prices. However, the Brattle-PJM-MADRI study assumed that all non-curtailed load was exposed to market prices, whereas the present analysis assumes conservatively that only a fraction of load is exposed to market prices. The remainder is assumed to be covered by pre-existing contracts that were priced without anticipating the effects of newly-introduced DSM. It is assumed that in any given year, 50 percent of load-serving obligations are supplied by pre-existing wholesale contracts, and 50 percent are supplied by new contracts under the “Immediate Supplier Reaction” scenario. In the “Slower Supplier Reaction” scenario 5/6th of the load is assumed to be affected. These assumptions result in discounted customer benefits relative to the Brattle-PJM-MADRI study – a 50 percent discount in the “Immediate Supplier Reaction” scenario and a 17 percent discount in the “Slower Supplier Reaction” scenario.

A second difference from the Brattle-PJM-MADRI study is the quantification of real-time DR benefits. The Brattle-PJM-MADRI study quantified benefits for only day-ahead DR and discussed qualitatively the potential additional value from DR that is dispatchable in real-time and thereby able to mitigate the effects of real-time surprises in supply and demand. In the present analysis, it is assumed that loads under direct load control are dispatchable in real-time, and the corresponding premium is estimated using the ratio of historical super-peak RT prices to super-peak DA prices. As an alternative, benefits are also estimated under the assumption that dynamically-priced loads can be activated in near real-time by designating peak periods day-of rather than day-ahead.

A third difference is that the present analysis includes an estimate of the capacity price impact from DR, whereas the Brattle-PJM-MADRI study did not address capacity price impacts. DR’s role in capacity markets has increased with the recent inception of PJM’s RPM. RPM allows demand-side resources to sell capacity into capacity auctions on equal footing with supply-side resources as long as they are on direct load control (by the utility, competitive retail providers, curtailment service providers and dispatched by the RTO). Load reductions that are not under direct load control, including dynamic pricing and energy efficiency, can not sell supply into capacity markets, but they would similarly impact capacity prices by reducing peak electricity demand and thereby the PJM load forecast and thus the administratively-determined demand curve for capacity.

Capacity price impacts are estimated as follows: in the “Immediate Supplier Reaction” and “Slower Supplier Reaction” scenarios it is assumed that there is no capacity price impact.

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13 Benefits are partially offset approximately 15 percent by associated reductions in the value of FTRs, as described in the Brattle-PJM-MADRI study.

14 This assumed turnover rate corresponds roughly to the contract lengths and schedules by which standard offer service is procured in D.C., Delaware, and Maryland and basic generation service is procured in New Jersey.

consistent with the scenario definition that the market is in an economic equilibrium with the expected 3-year forward capacity price set by Net CONE, irrespective of the level of load and load reductions expected. In the "Delayed Supplier Reaction" scenario, the market is in a scarcity situation, and high capacity prices are mitigated somewhat by reductions in peak load. Capacity price impacts are estimated by intersecting supply and demand curves for capacity in the Eastern MAAC and Southwestern MAAC Locational Delivery Areas (where all the PHI zones are located) both with and without DR. The demand curve is constructed using PJM's load forecast and the other parameters used to determine the administratively-determined demand curve. The supply curve is constructed by adding projected new supply (from the generation interconnection queue) to the supply curve available from the most recent capacity auction.

The final, and perhaps most important, enhancement to the Brattle-PJM-MADRI study is the scenario analysis discussed in Section 3.1.3. The various scenarios address the rate at which short-term price impacts are offset by suppliers' reactions to DSM.

4.0 FORECASTING PHI'S PEAK DEMAND REDUCTIONS DUE TO DYNAMIC PRICING

4.1. OVERVIEW

Deployment of AMI will allow PHI to provide dynamic rates to all of its distribution customers. This is expected to yield additional significant reductions in peak demand beyond those that would be achieved through energy efficiency and direct load control programs. Specifically, dynamic pricing would allow PHI to provide customers with time-varying rates that can be varied in response to situations in which the market price of electricity is high, or in response to conditions that would lead to decreased system reliability, such as unit outages. Dynamic rates typically provide a strong incentive to the customer to reduce demand during a utility-specified "critical peak period." This incentive could be in the form of a higher price during that period (accompanied by a discount during the non-critical hours) or in the form of a rebate for every kWh that is conserved during the critical-peak hours relative to a customer baseline usage level. Either way, the rates are designed to provide peak reductions to the utility when they are needed most, while at the same time giving the utility's customers the opportunity to achieve bill savings.

The purpose of this section is to quantify the peak reductions that PHI might expect to achieve by providing a dynamic pricing option to its customers. Much of this analysis relies on a model for predicting customer demand response to time-varying and dynamic rates (The Price Impact Simulation Model, or "PRISM") that was developed during the California Statewide Pricing Pilot (SPP). In order to yield meaningful information for companies in the PHI footprint, the PRISM model has been calibrated to PHI's system characteristics, such as weather conditions,

¹⁶ PHI's AMI rollout is currently scheduled to begin in 2009 and continue through the end of 2012. AMI will be deployed in five of PHI's jurisdictions (Pepco MD, Pepco DC, Delmarva MD, Delmarva DE, and Atlantic City Electric).
load profiles, saturation of central air conditioning ("CAC") and existing rates. With these inputs, PRISM is used to forecast the customer-level peak demand reductions that would occur in response to various PHI-specific dynamic rates. When combined with a forecast of the number of customers participating in the rate, the result is a system-wide forecast of annual peak demand reductions. The peak demand reductions is expected to yield supply-side benefits, such as lower capacity and energy costs, as well as other additional benefits like wholesale market price mitigation. Figure 4.1 summarizes this process.

**Figure 4.1. Forecasting the Financial Benefits of Dynamic Pricing**

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**4.2. DESCRIPTION OF PRISM**

PRISM was developed during the California SPP. The purpose of the SPP was to measure the change in consumption patterns that customers would exhibit when the structure of their rate was changed from a non-time varying rate to one that was time varying and dynamic, such as critical peak pricing (CPP). The experiment involved over 2,500 residential and small commercial and industrial (C&I) customers and spanned a period of more than two years. Ultimately, the SPP produced estimates of customer response to dynamic rates. These estimates varied not only with the dynamic rate design (i.e. price level during the critical peak and off peak periods) but also with information about the region's average load profile, weather, and CAC saturation. It is because of this additional functionality that PRISM's estimations of demand response can reflect not only California-specific conditions, but also be calibrated to provide an estimate of demand response in PHI's service territories.

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Inputs to PRISM were developed using data specific to PHI's service territories. The development of each input and their relevance to the modeling effort are described in the following sections.

4.2.1. The Representative Dynamic Rate

In order to estimate the impacts of dynamic pricing for PHI, it was necessary to model a specific rate design that would be representative of the type of dynamic rate that customers with AMI might be enrolled in. Examples of dynamic rate designs include real time pricing (RTP), Peak Time Rebate (PTR, also known as Critical Peak Rebate, or CPR), and CPP. For this analysis, we used the CPP rate that was designed by SMPI as part of the PowerCentsDC Pilot. This rate was selected because it has already been designed to reflect PJM day-ahead market prices. It can also be used conveniently with PRISM, because the California SPP specifically measured customer response to CPP rates. The all-in CPP from the PowerCentsDC Pilot is illustrated in Figure 4.2.

**Figure 4.2. Illustration of PowerCentsDC All-in Summer CPP Rate**

![Image of PowerCentsDC All-in Summer CPP Rate](image)

The CPP rate would charge customers around $0.83/kWh during critical peak hours, representing a surcharge of $0.70/kWh over the current all-in rate of $0.125/kWh. In return, customers are given a discount of about $0.013/kWh discount during all other hours of the summer (which represent 2,880 hours or over 98 percent of the total hours in the summer).

This CPP rate is designed to be revenue neutral for Pepco DC's residential customer base. This means that the utility would not gain or lose revenues if all residential customers were enrolled in the CPP rate (in the absence of any changes to consumption patterns). In other words, the
average customer's electric bill would not change if he switched from his current rate to the new CPP rate. Roughly 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). Of course, this is all in the absence of demand response. As customers change load patterns in response to the new CPP rate, a higher percentage will see bill savings.

The CPP rate represented here is the all-in rate. It includes transmission, distribution, and other charges in addition to the generation rate. These charges, derived from Pepco DC’s current Schedule "R" summer residential rate, are as follows:

- Fixed charge = $3.31/month
- Transmission charge = $0.004/kWh (applied to usage in excess of 30 kWh)
- Distribution charge = $0.0095/kWh (in excess of 30 kWh and less than 400 kWh) and $0.0285/kWh (in excess of 400 kWh)
- Other charges and credits = $0.009/kWh (applied to all usage)

These charges are used to calculate the non-generation portion of the average customer's bill (assuming monthly consumption of 1,048 kWh). This bill is then divided by consumption to arrive at the $/kWh non-generation charge of $0.037/kWh that is added to the generation-only CPP charge.

This CPP rate design was used for residential and small C&I customers in all five of PHI’s jurisdictions for analysis purposes. However, because the rate is currently designed to be revenue neutral for Pepco DC’s residential customers, it must be altered to reflect differences in the current rates for customers in other jurisdictions. To do this, both the critical peak rate and the off peak rate were simply scaled up or down using the ratio of the jurisdiction’s existing all-in rate relative to that of Pepco DC. The resulting CPP rates for each jurisdiction and customer type are summarized in Table 4.1.

18 More detail on the calculation of the existing all-in rate will follow in a later section.
The CPP rate is assumed to be dispatched on 12 critical days during the summer. Since each critical event lasts four hours, this represents a total of 48 critical hours during the summer. During the remaining 2,880 hours of the summer,\(^{19}\) customers receive the discounted off-peak price. Customers are notified the day before a critical event will be dispatched. More detail on the CPP rate design can be found in Pepco’s July 2007 list of rate schedules.\(^{20}\)

### 4.2.2. Residential Load Shapes

Load shapes for the average residential customer are used to determine the kilowatt-hour per hour impacts that are produced by each customer in response to the CPP rate. In other words, PRISM produces an estimate of the percent reduction in peak demand that each customer will provide, but the average load shapes for PHI’s customers are necessary to translate this into a unit impact that is specific to PHI.

For the residential customers, historical load profile data for the average Schedule “R” customer in each jurisdiction was used to develop the average load shapes.\(^{21}\) Average hourly consumption is calculated for two periods – the critical peak and the off peak – for the period from June to September 2006 using the load profile data.\(^{22}\) The results are summarized in Table 4.2.

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\(^{19}\) The analysis of load reductions likely to be achieved by CPP assumes four-hour events, but the benefits component of this study assumes the same level of load reductions would be extended to five hours in order to be consistent with the Brattle-PJM-MADRI study, from which some of the customer benefits are derived.


\(^{21}\) Based on load profile data collected between 1990 and the current date.

\(^{22}\) Critical days are identified as the 12 non-holiday weekdays with the highest maximum daily temperature.
4.2.3. Commercial and Industrial Customers’ Load Shapes

Average C&I load shapes are needed to produce kilowatt-hour per hour peak reduction estimates for the C&I customers. In calculating the load profiles, it is important only to include customers that will be equipped with AMI. Although PHI’s largest customers will also be equipped with AMI, they are not included because they already have interval meters. While these customers could still enroll in a dynamic rate, their peak reductions are not considered to be additionally enabled by AMI and therefore are not included in the analysis. The peak demand “cutoff” point above which C&I customers would not be equipped with AMI varies by utility as follows: 500 kW for Pepco DC and Pepco MD, 300 kW for Delmarva DE and Delmarva MD, and 1 MW for ACE.

The remaining non-interval metered customers could be on one of a number of different rate schedules. This is unlike the residential customers who are primarily on the “R” schedule. Thus, it was necessary to calculate a weighted average load profile across the rate schedules within each jurisdiction, using the number of non-interval metered customers on each rate schedule as the weights. The resulting C&I load shapes are summarized in Table 4.3.

4.2.4. Existing All-In Rates

The existing rate is a necessary input to the analysis, because a customer’s responsiveness to a new CPP rate will be driven by the price increase or decrease that the CPP rate provides relative to the customer’s existing rate. In other words, during the critical peak hours, a customer is responding not just to the high absolute price level of the CPP, but to the relationship of that price to the existing rate. Similarly, in the off peak, the customer’s response is assumed to be driven by the relative discount that he or she receives through the CPP rate.
Existing all-in rates were calculated for the average residential and C&I customers in all five jurisdictions. For residential customers, the “R” rate schedule for each jurisdiction was used to calculate the average customer’s monthly summer electricity bill. The average monthly consumption estimates that were used to calculate this bill were presented in Table 4.4. Once the total bill was calculated, it was divided by the monthly consumption to arrive at an all-in rate expressed in dollars per kilowatt-hour. Table 4.4. below summarizes the existing residential rates by jurisdiction.

Table 4.4. Existing Residential All-In Summer Rates

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>&quot;R&quot;</th>
<th>&quot;R&quot;</th>
<th>&quot;R&quot;</th>
<th>&quot;R&quot;</th>
<th>&quot;RS&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Bill</td>
<td>132</td>
<td>178</td>
<td>118</td>
<td>133</td>
<td>133</td>
</tr>
<tr>
<td>Rate</td>
<td>0.125</td>
<td>0.158</td>
<td>0.145</td>
<td>0.143</td>
<td>0.165</td>
</tr>
</tbody>
</table>

Existing C&I rates were calculated in a similar manner. The difference with the C&I customers, as mentioned previously, is that they are spread across different rate classes. As a means of approximately representing the typical C&I electricity rate, we identified the single rate schedule with the largest share of non-interval metered C&I load and used that rate schedule to calculate the monthly summer bill for the average customer. This bill was divided by the monthly consumption to arrive at the existing all-in rate. These rates are summarized in Table 4.5. for each jurisdiction.

Table 4.5. Existing C&I All-In Summer Rates

<table>
<thead>
<tr>
<th>Rate Schedule</th>
<th>&quot;GT LV&quot;</th>
<th>&quot;MGT LV II&quot;</th>
<th>&quot;SGS-S I&quot;</th>
<th>&quot;MGS-S&quot;</th>
<th>&quot;MGS-S&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Bill</td>
<td>1,469</td>
<td>1,303</td>
<td>665</td>
<td>253</td>
<td>382</td>
</tr>
<tr>
<td>Rate</td>
<td>0.160</td>
<td>0.147</td>
<td>0.166</td>
<td>0.115</td>
<td>0.163</td>
</tr>
</tbody>
</table>
4.2.5. Saturation of Central Air Conditioners

The CAC saturation of a region can be expected to influence its expected peak reduction. Generally, customers with CAC have a greater ability to reduce consumption during peak times, because they can have direct control over their thermostat (and in many cases can even program the thermostat to automatically increase the temperature and thus reduce electricity consumption during the peak period of the day). Thus, all things being equal, in a region where a large percentage of customers have CAC, the expected peak demand reduction will be higher than in a region where a small percentage of customers have CAC.

CAC saturation rates for the five jurisdictions were provided by PHI and are summarized in Table 4.6.

Table 4.6. CAC Saturation Rates

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>PHI</th>
<th>PHI, MD</th>
<th>PHI, NJ</th>
<th>PHI, NY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salisbury, MD</td>
<td>45%</td>
<td>66%</td>
<td>42%</td>
<td>42%</td>
</tr>
<tr>
<td>Wilmington, DE</td>
<td>11%</td>
<td>19%</td>
<td>11%</td>
<td>11%</td>
</tr>
<tr>
<td>Atlantic City, NJ</td>
<td>56%</td>
<td>84%</td>
<td>53%</td>
<td>53%</td>
</tr>
<tr>
<td>Reagan National Airport, DC</td>
<td>97%</td>
<td>97%</td>
<td>97%</td>
<td>97%</td>
</tr>
</tbody>
</table>

4.2.6. Temperature Statistics

Temperature has also been found to be correlated with peak reductions from dynamic pricing. Generally, hotter regions tend to experience greater peak reductions. Two specific temperature statistics are used as inputs to PRISM: Peak vs. off peak temperature differentials and the average daily temperature. These statistics have been computed using historical hourly temperature observations from the following locations:

- Salisbury, MD
- Wilmington, DE
- Atlantic City, NJ
- Reagan National Airport, DC

It should be noted that humidity could also have an additional impact on the expected peak reductions. However, because PRISM is based on a study conducted in California, where humidity levels are low and do not vary greatly from region to region, it does not account for the potential influence of humidity.
4.3. CUSTOMER-LEVEL IMPACTS

Using the previously described inputs, peak demand impacts were simulated for the average residential and C&I customers in each of the five jurisdictions. These impacts are summarized in Figure 4.3 and Figure 4.4.

Impacts for C&I customers are estimated to be 30 percent of the impacts for a residential customer on the same rate. In other words, if a residential customer were to reduce peak demand by 10 percent in response to dynamic pricing, a C&I customer on the same rate would reduce peak demand by three percent. This is a conservative estimate that is supported by the findings of the C&I impacts study that was conducted through the California SPP. 24

A share of PHI’s customers will be participating in a direct load control (DLC) program. Through this program, PHI would control the participating customers’ CAC systems through a device called a “smart thermostat” and would have the ability to reduce the customers’ CAC load on peak days through the thermostat. It is important not to double-count the CAC-related peak reductions for these customers by attributing their impacts to both the DLC program and to dynamic pricing. Thus, for the purposes of this analysis, the CAC-related peak reductions from these customers will not be counted toward the CPP rate. However, the DLC customers would still have the opportunity to participate in the CPP rate and could further reduce their consumption by other end uses in response to the dynamic rate. 25 These incremental peak reductions should be attributed to the CPP. To account for this, the residential DLC customers are modeled as customers who do not have CAC. As a result, their peak demand impact represents the expected reduction at the other end uses and is smaller than that of the average customer. Expected impacts for these customers are also presented in Figure 4.3 and Figure 4.4.

To remain conservative in our estimation of peak reductions, C&I customers participating in the DLC program have been excluded entirely from the analysis of dynamic rates. In other words, these customers’ CAC peak demand reduction is attributed to the DLC program, and they are not assumed to provide an additional demand reduction that can be attributed to the dynamic rate.


25 For example, customers could refrain from running their clothes dryers until after the critical peak period ends. This would represent a peak demand reduction incremental to any reduction that would be attributable to the DLC program, which only has an impact on load created by the CAC system.
Privileged and Confidential DRAFT

Figure 4.3. Expected Average Critical Peak Reductions (Percent of Critical Peak)

The higher expected peak reduction from Pepco MD’s customers (on a percentage basis) can be explained by the higher CAC saturation rate in that jurisdiction. In all jurisdictions, the average residential customer is expected to produce a greater peak reduction on a percentage basis than that the peak reduction from the average C&I customer. However, this does not always translate into a greater peak reduction on kilowatthours-per-hour basis. This depends on the size of the customer. In fact, in three out of the five jurisdictions, the larger size of C&I customers leads to a greater kilowatthours-per-hour reduction per customer.
Due to the larger size of C&I customers in Pepco’s jurisdictions, these customers are expected to produce the largest average peak reductions. Critical peak reductions from other customers range from 0.2 kWh/hr to 0.6 kWh/hr.

4.4. FORECASTING CUSTOMER PARTICIPATION

The estimates of the peak kilowatt reductions per customer can be combined with a forecast of the number of customers participating in the dynamic rate. The result is an annual system-wide forecast of peak impacts for each jurisdiction. The following sections describe the assumptions used in developing the forecast of participating customers.

4.4.1. Customers Eligible for AMI

Customers can only enroll in a dynamic rate if they are equipped with AMI, because this allows their electricity consumption to be measured in hourly intervals (or shorter) as opposed to being measured on a monthly basis. All residential customers will be equipped with AMI. Of the C&I customers, only those without interval meters will be equipped with AMI.\(^{26}\) The number of

\(^{26}\) C&I non-interval meter services are used as an approximate representation of the number of eligible C&I customers.
eligible customers is summarized in Table 4.7, along with the annual growth rates that are assumed for each segment of the population.

Table 4.7. 2006 Customer Population Estimates and Annual Growth Rates

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>211,220</td>
<td>469,138</td>
<td>169,993</td>
<td>262,684</td>
<td>474,921</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>24,704</td>
<td>45,248</td>
<td>27,312</td>
<td>32,625</td>
<td>53,096</td>
</tr>
<tr>
<td>Rural</td>
<td>0.9%</td>
<td>0.5%</td>
<td>1.4%</td>
<td>1.3%</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

4.4.2. AMI Deployment Schedule

The current plan is to deploy AMI to customers over the period from 2009 to 2013. The deployment schedule varies by jurisdiction. It is assumed that customers are eligible to participate in dynamic pricing once they have been equipped with AMI. In other words, it is not necessary for a jurisdiction to achieve 100 percent of its scheduled deployment before customers can begin enrolling in the CPP rate. Table 4.8 below summarizes the AMI deployment schedule and Figure 4.5 and Figure 4.6 combine this with the population forecasts to show the total number of customers equipped with AMI in each year from 2009 until full deployment in 2013.27

Table 4.8. Mid-Year AMI Deployment Schedule (Residential and C&I)

<table>
<thead>
<tr>
<th>Year</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>0%</td>
<td>0%</td>
<td>25%</td>
<td>50%</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>0%</td>
<td>35%</td>
<td>75%</td>
<td>100%</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>50%</td>
<td>80%</td>
<td>100%</td>
<td>100%</td>
<td>25%</td>
<td></td>
</tr>
<tr>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>75%</td>
<td></td>
</tr>
<tr>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

27 It should be noted that PHI provided an end-of-year AMI deployment schedule, and a mid-year schedule was used in the analysis to approximate the number of customers with AMI during the summer CPP season. Mid-year values were obtained through linear interpolation.
By the end of 2013, over 1.7 million residential customers are expected to be equipped with AMI. Both Pepco MD and ACE are anticipated to have deployed AMI to around 500,000 residential customers, accounting for nearly 60 percent of PHI's total residential deployment.
Nearly 200,000 C&I customers will be equipped with AMI in PHL's service territories by the end of 2013. Over 50,000 C&I customers in ACE will be equipped with AMI, representing nearly 30 percent of the total non-interval meter C&I deployment.

4.4.3. Customer Participation in Direct Load Control

As was described previously, peak impacts from DLC customers must be treated differently than the other customers due to the fact that their CAC-related peak reductions are not attributable to the CPP rate. Thus, a separate forecast of the number of DLC customers is needed. Figure 4.7 and Figure 4.8 below summarize this forecast for residential and C&I customers, as provided by PHL.28

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28 It is assumed that all C&I DLC customers are equipped with AMI rather than interval meters.
Figure 4.7. Forecast of Participation in PHI's Residential DLC Program

Nearly 200,000 residential customers are expected to be participating in the DLC program by the end of 2014. The forecast is designed to coincide with the AMI deployment schedule. It is important to note that 100 percent of DLC customers are assumed to participate in the dynamic rate. This is because, due to the peak reduction that these customers automatically provide through the DLC program, they are in a position to realize instant bill savings under the dynamic rate and would not have an incentive to remain on the original rate.
Over 25,000 C&I customers are expected to participate in the non-residential DLC program by the end of 2013. ACE is forecasted to have over half of all participants. All of the non-residential DLC customers are assumed to be enrolled in the dynamic rate, but their impacts are not counted toward the system-wide peak reduction attributable to dynamic pricing. This is done to avoid double-counting with DLC peak impacts that are reported separately.

4.4.4. Enrollment Rate

Enrollment in the dynamic rate will depend heavily on how the rate is offered to PHI’s customers. For example, it could be offered as the default rate, where all customers are put on the dynamic rate with the option of switching back to their original rate. The expected participation resulting from this type of offering would be much higher than if the dynamic rate were offered on a voluntary basis, where customers were simply provided with the option of signing up for the rate and otherwise would stay on the existing rate structure. There is a significant amount of uncertainty around what enrollment would be like under these various

29 There are many ways in which customers could be phased into such a rate offering. For example, if all customers were initially placed on the dynamic rate, they could be given full bill protection for the first year of enrollment and this bill protection could be phased out over a three to five year window. This would ensure that customers would understand the potential benefits of the new rate before making a decision on whether to stay on the new rate or switch over to a flat rate.
scenarios. Studies have suggested that under the “CPP-Default” scenario, 80 percent of eligible customers could remain on the dynamic tariff. The “CPP-Voluntary” scenario, on the other hand, might lead to only around 20 percent participation in the rate. Due to the wide range of uncertainty surrounding this assumption, we have chosen to analyze the system-wide peak impacts under these two polar scenarios, assuming the participation rates described above.

These participation rates are not anticipated to be achieved in the first year of the study. In the case of the CPP-Default scenario, enrollment will ramp down from 100 percent in the first year (2009) to 80 percent by 2013. Similarly, for the CPP-Voluntary scenario, participation ramps up from zero to 20 percent by 2013.

It should also be noted that, in PHI’s service territories, customers have the option of “shopping” for another retail supplier of electricity. PHI expects that some customers will exercise this option. For the purposes of this analysis, it is assumed that the alternative retail supplier will offer a dynamic pricing scheme similar to the one being modeled, and that the customers who shop will adopt the dynamic pricing option at the same rate as those customers who do not shop. Due to the fact that the AMI deployment has enabled these customers to enroll in the dynamic rate, their impacts are included in the final estimation of peak demand reductions even though PHI is no longer their supplier.

For an illustration of how these factors would determine the number of participating customers, see Figure 4.9. It illustrates the breakout of residential DLC customers, participants, and non-participants under the CPP-Default scenario for Pepco DC in 2013. In this scenario, 82 percent of all residential customers would participate in the dynamic rate.
Figure 4.9. Share of Participating Residential Customers in Pepco DC in 2013 (CPP-Default Scenario)

Of all customers with AMI, 10% are in the DLC program and are enrolled in the dynamic rate...

Of the remaining non-DLC customers, 80% remain enrolled in the dynamic rate and 20% enroll in their original rate...

With all of these factors accounted for, the result is a forecast of residential and C&I customers enrolled in the CPP rate in both the CPP-Default scenario and the CPP-Voluntary scenario. These forecasts are summarized in Figure 4.10 and Figure 4.11 below.
Figure 4.10. Forecast of Total Residential CPP Enrollment in All PHI Jurisdictions

Over 1.4 residential customers are expected to enroll in the dynamic rate by the end of 2013 if it is offered as the default rate. Around 500,000 are expected if it is offered as a voluntary rate.
Figure 4.11. Forecast of Total C&I CPP Enrollment in All PHI Jurisdictions

Over 160,000 C&I customers are expected to enroll in the dynamic rate by 2013 if it is offered as the default rate. Approximately 60,000 are anticipated to enroll if it is offered as a voluntary rate.

4.5. **System-Wide Peak Demand Impacts of Dynamic Pricing**

Multiplying the per-customer kilowatthours-per-hour peak reductions by the forecast of participating customers results in an annual forecast of system-wide peak demand reductions for PHI's service territories. These forecasts are summarized in Figure 4.12 for the CPP-Default scenario and Figure 4.13 for the CPP-Voluntary scenario.
Figure 4.12. System-Wide Peak Demand Reductions Attributable to Dynamic Pricing
CPP-Default Scenario

Under the CPP-Default scenario, the total peak reduction attributable to dynamic pricing will be nearly 60 MW in 2009, the first year of AMI deployment. This is expected to grow to over 600 MW by 2013. Nearly 40 percent of the 2013 demand reduction comes from Pepco MD.
The CPP-Voluntary scenario provides significantly smaller reductions in peak demand (note the difference in the figure's y-axis scale compared to the figure showing impacts for the CPP-Default scenario). The expected forecast is for 15 MW of peak reduction in 2009, growing to nearly 180 MW by 2013. By the end of 2013, the peak reductions are less than 30 percent as large as those under the CPP-Default scenario. This is driven by the much lower participation rate.

5.0 RESOURCE COST SAVINGS

Ongoing DSM creates lasting value by reducing the amount of physical capacity that needs to be built to reliably meet peak load, and by reducing the amount of generation (the value of which is partially offset by the lost value of service to the customer) and ancillary services required from physical resources. Customers benefit by having to buy a lesser volume of capacity and energy and by being able to sell ancillary services.
5.1. CAPACITY SAVINGS

5.1.1. Theory

Reducing peaks loads reduces the amount of capacity that load serving entities (and ultimately customers) are required to purchase in order to maintain resource adequacy for reliability, eventually resulting in fewer new generation plants having to be built and enabling the retirement of the most expensive, dirtiest old plants. The annual customer savings is given by the product of the annual MW reduction in capacity requirements and the $/MW-year value of capacity.

The annual reduction in physical capacity requirements can be estimated by assuming that all expected DR would provide capacity or reduce the load forecast, thus avoiding the need for physical capacity to the extent that the simultaneous peak load forecast is reduced in each PJM locational delivery area (LDA), multiplied by 1 plus the reserve margin. The reduction in simultaneous peak load forecast is given by the sum of projected peak load reductions in all jurisdictions (shown in Figure 5.1) discounted by a load diversity factor representing the fact that not all jurisdictions’ peak loads coincide with the system peak.

Peak load reductions are adjusted by a reserve margin to account for the fact that some capacity is maintained as a buffer above the expected peak load in order to meet a desired level of reliability. The most commonly used reserve margin metric, the installed reserve margin (IRM), is one of the key parameters of PJM’s RPM capacity market (currently 15 percent).

The value of an incremental reduction in capacity requirements is given by the market price for capacity. The market price for capacity is what retail providers or wholesale suppliers of standard offer service would otherwise pay for incremental capacity and presumably pass on to the customer. Hence, estimating customers’ capacity savings requires estimating the expected annual capacity price.

Actual capacity prices are determined by PJM’s reliability pricing model and market factors including load growth, DSM penetration, boom and bust cycles of construction, environmental regulations, the cost of new capacity, and other factors that are difficult to predict accurately for any given future year. In expectations, however, it is reasonable to assume that, barring barriers to entry, future markets will be in a competitive equilibrium in which suppliers earn their cost of capital, i.e., they neither over-invest and earn less than their cost of capital in a surplus market, nor do they under-invest and miss opportunities to make above-market returns in a tight market. At equilibrium, the capacity price should be equal to the Net Cost of New Entry (Net CONE), which can be expected to just cover a generating plant’s capital costs and fixed operating and maintenance costs that are not offset by operating earnings from selling energy and ancillary services.

Using Net CONE to value reductions in peak load is more conservative than using CONE, which is often used in DSM cost-effectiveness tests. Net CONE represents the resource cost and the expected capacity price that customers will pay (and avoid). It accounts for the fact that suppliers’ operating margins on sales of energy and ancillary services help to offset the cost of building and maintaining a generation plant. Net CONE also represents the net system cost of having a plant online, i.e., the capital and fixed O&M costs less the system cost savings from dispatching the plant when it has a lower variable cost than alternative resources.
The cost of new entry of course varies by technology. However, assuming the market is in an equilibrium in which a mix of technologies is economic to build, all technologies must have the same Net CONE, with the technologies that have relatively high capital and fixed costs enjoying higher operating margins. PJM (and other RTOs) uses the Net CONE for a combustion turbine (CT) as a generic Net CONE in determining the parameters for its Reliability Pricing Model (RPM).

5.1.2. Methodology

In the "Immediate Supplier Reaction" and "Slower Supplier Reaction" scenarios, it is assumed that the market is in equilibrium starting in 2009, with the capacity price set by PJM's current official estimate of Net CONE. PJM's current Net CONE is $51/kW-yr in the Eastern MAAC Locational Delivery Area (LDA) and $54.5/kW-yr in the Southwestern MAAC LDA, based on recent CT costs and operating margins. These figures are assumed to stay constant in real terms over the study horizon. Holding PJM's current Net CONE constant in real terms is highly conservative because it does not account for the dramatic increases in the cost of new capacity that have occurred recently, which will probably lead to substantially higher capacity prices in the future if today's PJM market prices persist or rise further. A recent Brattle study sponsored by the Edison Foundation finds that recent increases in the costs of steel, specialty parts, and specialty labor have increased the cost of new CTs by 17 percent in 2006 and increased the cost of new steam generation by 25-35 percent between 2004 and 2007.

In the "Delayed Supplier Reaction" scenario, the market is assumed to be in a scarcity situation until 2014, when it reaches equilibrium and capacity prices fall to Net CONE. For 2009 through 2013, capacity prices are estimated based on the intersection of projected supply and demand curves. Supply offer curves for 2010/11 and 2013/14 were derived from the 2007/08 offer curve by: (1) removing likely retirements at net avoidable going-forward costs used in PJM simulation for each unit type; (2) adding capacity in advanced stages of project development from PJM Generation Queue; and (3) assuming all other offers stay the same. Demand curves, which PJM refers to as the "Variable Resource Requirement" (VRR), are based on parameters for the 2009/10 base residual auction (BRA). The Reliability Requirement in each LDA is assumed to grow at the rate of peak load growth, as projected by PJM.

Applying the methodology described above to the "Delayed Supplier Reaction" scenario produces capacity prices of $190/MW-day in 2010 and $223/MW-day in 2013 EMAAC and $237/MW-day in 2010 and $239/MW-day in 2013 in SWMAAC. Capacity prices fall to Net CONE in 2014, when it is assumed that sufficient new supply is added to bring the market back to economic equilibrium.

---


5.1.3. Results

Resulting estimates of customer benefits from avoided capacity purchases resulting from PHI’s DSM programs are shown for years 2010 and 2013 in Tables 5.1 and 5.2, respectively. 2010 and 2013 are used as representative years from which the benefits in all other years are interpolated and extrapolated based on relative amounts of load reductions.

Tables 5.1 and 5.2 also show the key elements of the calculation that was described in Section 5.1.2. (Note that the peak load and total load estimates are taken from the normalized load data used in the Brattle-PJM-MADRI study, and they are not escalated to account for load growth).

Table 5.1. Estimated Capacity Savings in 2010

<table>
<thead>
<tr>
<th>Supply Response Scenario</th>
<th>CPP-Voluntary</th>
<th>CPP-Default</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Immediate</td>
<td>Slower Delayed</td>
</tr>
<tr>
<td>Peak Load (MW)</td>
<td>13,480</td>
<td>13,480</td>
</tr>
<tr>
<td>Total Load (MWh)</td>
<td>758,523</td>
<td>758,523</td>
</tr>
<tr>
<td>Jurisdictional Reduction (MW)</td>
<td>220</td>
<td>220</td>
</tr>
<tr>
<td>Reductions Not Offset by Supplier Response</td>
<td>103</td>
<td>220</td>
</tr>
<tr>
<td>Avoided Capacity Costs (millions 2007 $)</td>
<td>$13</td>
<td>$11</td>
</tr>
</tbody>
</table>

Table 5.2. Estimated Capacity Savings in 2013

<table>
<thead>
<tr>
<th>Supply Response Scenario</th>
<th>CPP-Voluntary</th>
<th>CPP-Default</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Immediate</td>
<td>Slower Delayed</td>
</tr>
<tr>
<td>Peak Load (MW)</td>
<td>13,480</td>
<td>13,480</td>
</tr>
<tr>
<td>Total Load (MWh)</td>
<td>757,505</td>
<td>757,505</td>
</tr>
<tr>
<td>Jurisdictional Reduction (MW)</td>
<td>570</td>
<td>570</td>
</tr>
<tr>
<td>Reductions Not Offset by Supplier Response</td>
<td>101</td>
<td>350</td>
</tr>
<tr>
<td>Avoided Capacity Costs (millions 2007 $)</td>
<td>$29</td>
<td>$20</td>
</tr>
</tbody>
</table>

5.2. GENERATION SAVINGS

5.2.1. Theory

Reducing low-value or time-flexible uses of electricity during peak periods when prices are very high clearly saves fuel and creates economic value that accrues to customers if rate structures provide the appropriate incentives and rewards.

Generation savings depend on the particular type of generation that is not dispatched as a result of load reductions, which could include a combination of old capacity running less (or retiring) or new capacity not being constructed and dispatched. The value of reduced generation is also partially offset by the value the customer forgoes by not consuming as much power. Assessing the forgone value to the customer is difficult to assess and is highly variable; it also depends on whether the customer shifts load to lower-priced periods.
5.2.2. Methodology

This study estimates generation savings by adopting the results of the Brattle-PJM-MADRI study, in which net generation savings amounted to an additional 12-36 percent on top of capacity savings. This study scales the benefits found in the Brattle-PJM-MADRI study based on the relative magnitude of load reductions.

It should be noted that although the Brattle-PJM-MADRI study was based on a dispatch model that was able to identify the change in generation resulting from DSM, it did not account for the fact that the amount of supply online could eventually change as a result of DSM. The avoided generation necessarily came from reductions in the dispatch of existing (probably old) capacity. Estimated generation savings might have been lower if the analysis had considered the possibility of reduced construction of new (relatively efficient) capacity forcing inefficient existing units to generate power even with DSM.

The Brattle-PJM-MADRI study did however account for the value the customer foregoes by reducing or shifting its consumption. A lower bound estimate was established in which customers lose no value, which might be possible if participation in DSM programs stimulates customers to pay attention to their energy usage and eliminate waste they had never considered before. An upper bound estimate valued the lost customer load at the spot price of power (it would be uneconomic to reduce load if the value were any higher). An intermediate value was based on the assumption that customers value their foregone or shiftable load at the minimum retail rate among customer classes, based on the theory that customers consume energy until the marginal value of their least valuable kilowatt-hour equals their retail rate, and the customers with the lowest retail rates have the lowest value marginal uses of energy, and thus are most likely to voluntarily reduce their consumption. The present analysis of PHI's DSM programs uses the intermediate estimate. (To the extent that mass market customers participants in dynamic pricing have a higher retail rate than the rate assumed in the Brattle-PJM-MADRI study, the lost customer value might be higher and the net generation savings overstated somewhat).

This approach is roughly applicable whether customers simply eliminate load or whether they shift load to non-peak periods. For example, if a customer reduces consumption valued at $100/MWh when spot prices are $300/MWh, the net savings is $200/MWh even if the customer shifts its consumption (at an inconvenience cost of, say, $20/MWh) to another hour with $80/MWh spot prices.

5.2.3. Results

Resulting estimates of customer generation savings (just the direct value of buying less quantity, not the price impact) are shown for representative years 2010 and 2013 in Tables 5.3 and 5.4, respectively. These tables also show the key elements of the calculation that was described in Section 5.2.2. (Note that the peak load and total load estimates are taken from the normalized load data used in the Brattle-PJM-MADRI study, and they are not escalated to account for load growth).
Table 5.3. Estimated Generation Savings in 2010

<table>
<thead>
<tr>
<th>Supply Response Scenario</th>
<th>CPP-Voluntary</th>
<th>CPP-Default</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Immediate</td>
<td>Slower</td>
</tr>
<tr>
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<td>13,480</td>
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</tr>
<tr>
<td>Total Load (MWh)</td>
<td>758,523</td>
<td>758,523</td>
</tr>
<tr>
<td>Jurisdictional Reduction (MW)</td>
<td>220</td>
<td>220</td>
</tr>
<tr>
<td>Reductions Not Offset by Supplier Response</td>
<td>103</td>
<td>220</td>
</tr>
<tr>
<td>Avoided Energy Costs (million 2007 $')</td>
<td>$3</td>
<td>$3</td>
</tr>
</tbody>
</table>

Table 5.4. Estimated Generation Savings in 2013

<table>
<thead>
<tr>
<th>Supply Response Scenario</th>
<th>CPP-Voluntary</th>
<th>CPP-Default</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Immediate</td>
<td>Slower</td>
</tr>
<tr>
<td>Peak Load (MW)</td>
<td>13,480</td>
<td>13,480</td>
</tr>
<tr>
<td>Total Load (MWh)</td>
<td>757,505</td>
<td>757,505</td>
</tr>
<tr>
<td>Jurisdictional Reduction (MW)</td>
<td>570</td>
<td>570</td>
</tr>
<tr>
<td>Reductions Not Offset by Supplier Response</td>
<td>101</td>
<td>350</td>
</tr>
<tr>
<td>Avoided Energy Costs (million 2007 $')</td>
<td>$7</td>
<td>$7</td>
</tr>
</tbody>
</table>

5.3. **ANCILLARY SERVICES BENEFITS**

Some DR could potentially provide spinning reserves or other ancillary services (A/S), by being able to turn off down for 30 minutes at a moments' notice. Provision of A/S could benefit customers directly if rate structures allow customers to be paid the market price for ancillary services. Demand-side provision of A/S also lowers total resource costs by reducing the need for reserves from supply-side resources, the marginal value of which is given by the market price for spinning reserves.

However, A/S value is somewhat speculative because currently the PJM market doe not currently permit small scale DR to participate in the ancillary markets. However, large DR currently provides small amounts of A/S in PJM and ISO-NE. It was assumed conservatively that AMI could eventually enable 100 MW of spinning reserves in all of PJM-E, amounting to 0.15 percent of peak load in all zones. The value of such reserves is estimated by multiplying a conservative quantity of spinning reserves by a historical average price of spinning reserves ($8.5/MWh for 2004-06)\(^{33}\) and by the number of hours in a year.

6.0 **SHORT-TERM ENERGY PRICE IMPACTS**

6.1. **THEORY**

The energy market will clear at a lower price if load is reduced (by DSM) while supply offers remain constant. With reduced prices, consumer surplus increases and producer surplus decreases. The increase in consumer surplus is what is measured as a customer benefit.

\(^{33}\) PJM website.
The concept can be illustrated with a supply and demand curve, shown in Figure 6.1. An illustrative supply curve is shown in blue; the demand curve is shown as a vertical line with no elasticity relative to spot prices, representing the fact that most customers are not exposed directly to changes in spot prices, so their short-term demand is unresponsive to spot prices (even if demand is responsive to changes in retail rates). Load reductions resulting from DSM is represented as a decrease in quantity demanded, from Q1 to Q2. This causes the spot price to drop from P1 to P2. The resulting increase in consumer surplus (and decrease in producer surplus) is given by area bcde, assuming that none of the load is hedged through forward contracts with generators. To the extent that load is hedged through pre-existing forward contracts that did not anticipate and incorporate the price effect of DSM, the price savings would be reduced, but only until the contracts expire and are replaced by new contracts that are based on refreshed market expectations.

Figure 6.1 represents a short-run equilibrium in which supply remains static in spite of a reduction in demand and prices. In the long-run, the supply side can be expected to adjust to the prospect of depressed returns by accelerating retirements and/or delaying new construction, thus increasing energy prices and eventually offsetting some or all of the short-term price reduction caused by DSM. (DSM does not permanently lower market prices any more than building a power plant permanently lowers market prices). The key question is how long it takes suppliers
to react. Supplier reaction time should depend on the time required to detect change in fundamentals and market prices, to incorporate such information into planning decisions, and lead times required for changing construction schedules and gaining PJM approval for retiring plants, as well as regulatory and siting constraints. Because these factors are quite difficult to predict, we have constructed three scenarios in which the long-term is 1 year, 3 years, and up to 5 years, as described in Section 3.

6.2. METHODOLOGY

Short-term energy price reductions are estimated by adapting the price impacts from the top 60 hours in the Brattle-PJM-MADRI study (January, 2007) to reflect the expected load reductions associated with PHI's programs. As before, the "benefit" is given by the product of the estimated price reduction and the residual load (to be discounted based on the fraction of load that is exposed to market prices, as discussed below). Benefits are partially offset by an associated reduction in the value of Financial Transmission Rights (FTRs) (about a 15 percent offset).

To the extent that PHI’s load reductions differ from the load reductions simulated in the Brattle-PJM-MADRI study, price impacts were linearly extrapolated (e.g., assume that twice the MW of load reductions would lead to twice the price impact). This linear approach does not consider that the marginal price effect probably diminishes as load reductions increase; that effect could be quantified by performing new simulations tailored to PHI’s programs.

As described in Section 3, benefits are estimated at the PHI zonal level (split across state lines where applicable), the state level, and the entire PJM-East region, assuming three alternative geographic scopes of load reductions: (1) each PHI jurisdiction in isolation; (2) all PHI jurisdictions in concert; and (3) the entire PJM-East region. Because these configurations differ from those analyzed in the Brattle-PJM-MADRI study, approximation and data manipulation was required in order to adapt the results, as follows:

- **For DSM implementation by each PHI jurisdiction in isolation, and all PHI jurisdictions in concert:** given the load reductions estimated for each PHI jurisdiction, price impacts are estimated using the results of the corresponding one-zone curtailment cases described in Table 5.5 of the Brattle-PJM-MADRI report. (PSEG was used as a proxy for Atlantic Electric because PSEG is the only zone in NJ for which load reductions were analyzed in the Brattle-PJM-MADRI study.) The effect of one PHI zone's load reductions on prices in another PHI zone was estimated using the cross-zone methodology described below.

- **For DSM implementation in the entire PJM-East region:** given the load reductions projected for each PHI jurisdiction, and assuming all other zones in PJM-East achieve a similar level of load reduction, the total price effect in each zone is estimated as a sum of the price effect resulting from local load reductions plus the cross-zone effect from load reductions in all other PJM-East zones. The price effect from local load reductions is
estimated as described above for isolated implementation. The additional impact on each zone’s energy prices from load reductions in all other PJM-East zones is estimated using the average price impact ($/MWh local price impact per MW of outside load reduction) resulting from the Brattle-PJM-MADRI study’s one-zone curtailment cases in which the local zone of interest did NOT reduce its load. For example, the effect of PECO’s load reductions on Pepco MD prices is based on the Pepco MD price impact observed in the PECO-only curtailment case in the Brattle-PJM-MADRI study (but the price impact is scaled using the ratio of PECO load reductions in the present study to that in the Brattle-PJM-MADRI study). Each zone’s price impact from load reductions in zones that were not studied in the Brattle-PJM-MADRI study, such as Allegheny, PPL, etc., is assumed to be the average (on a $/MWh per MW basis) of the price impacts from the five zones that were studied (excluding the local zone, e.g., estimating the impact of PPL on Delmarva by averaging the effects from load reductions in PSEG, PECO, Delmarva, and BG&E but not from Delmarva).

The results presented in the body of this report are based on an average of the price impacts simulated in the Low Peak and High Peak cases in the Brattle-PJM-MADRI study, which represented six percent deviations from weather-normalized 2007/08 load. (The appendix provides the range in addition to the average). Using an average of the High Peak and Low Peak is appropriate because it partially captures the non-linear increase in prices (and price sensitivity to DR) as market conditions become tighter. The High Peak case is probably conservative because it uses supply bids that were calibrated to a normal period, without accounting for the likely decrease in unit efficiency and availability or the potential for more aggressive bidding that might occur under very high temperature conditions.\(^*\)

Given the estimated reduction in prices in each zone, the customer benefit is calculated by multiplying the change in price by the amount of load exposed to market prices. Only a fraction of load is exposed to market prices. The remainder is assumed to be covered by pre-existing contracts. It is assumed that in any given year 50 percent of load-serving obligations are supplied by new contracts and 50 percent are supplied by pre-existing wholesale contracts, corresponding roughly to the rate at which wholesale contracts for standard offer service turn over in D.C., Delaware, Maryland and New Jersey. It is further assumed, conservatively, that pre-existing contracts were priced without anticipating the spot market impacts of newly-introduced DSM. Given this assumption, only half of load is affected by the 1-year-duration price impacts in the “Immediate Supplier Reaction” scenario. In the “Slower Supplier Reaction” in which price impacts persist for three years, 5/6th of the load is exposed. These assumptions result in discounted customer benefits relative to the Brattle-PJM-MADRI study — a 50 percent

\(^*\) The present study relies on the one-zone curtailment cases in the Brattle-PJM-MADRI study, for which only weather-normalized conditions were simulated, unlike the five-zone curtailment cases for which high peak and low peak conditions were simulated in addition to weather-normalized conditions. For one-zone curtailment, high peak and low peak impacts were estimated based on the assumption that the ratios of price impacts under alternative market conditions to the price impacts under weather-normalized conditions would be the same as in the five-zone curtailment cases in the Brattle-PJM-MADRI study.
discount in the "Immediate Supplier Reaction" scenario and a 17 percent discount in the "Slower Supplier Reaction" scenario. There is no discount in the "Delayed Supplier Reaction" scenario in which price impacts last through 2013.

In the long term, energy price impacts are likely to be offset by suppliers' adjustments to their capacity construction and retirement plans. The timing of this effect varies among the scenarios described in Section 3: in the "Immediate Supplier Reaction" scenario, the short-term price impacts last for 1 year after the deployment of each increment of DSM; in the "Slower Supplier Reaction" scenario, the short-term energy price impacts last for three years. In the "Delayed Supplier Reaction" scenario, the short-term energy price impacts last through 2013, about 1-5 years, depending on the deployment schedule of each increment of DSM.

6.3. RESULTS

Resulting estimates of customer benefits from short-term energy price impacts are shown for representative years 2010 and 2013 in Tables 6.1 and 6.2, respectively. These tables also show the key elements of the calculation that was described in Section 6.2. (Note that the peak load and total load estimates are taken from the normalized load data used in the Brattle-PJM-MADRI study, and they are not escalated to account for load growth).
Table 6.1. Estimated Energy Price Impacts in 2010

<table>
<thead>
<tr>
<th>Supply Response Scenario</th>
<th>Immediate</th>
<th>Slower</th>
<th>Delayed</th>
<th>Immediate</th>
<th>Slower</th>
<th>Delayed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
</tr>
<tr>
<td>Total Load (MW)</td>
<td>737,505</td>
<td>737,505</td>
<td>737,505</td>
<td>711,144</td>
<td>711,144</td>
<td>711,144</td>
</tr>
<tr>
<td>Jurisdictional Reduction (MW)</td>
<td>570</td>
<td>570</td>
<td>570</td>
<td>1,009</td>
<td>1,009</td>
<td>1,009</td>
</tr>
<tr>
<td>Reductions Not Offset by Supplier Response</td>
<td>101</td>
<td>101</td>
<td>101</td>
<td>119</td>
<td>119</td>
<td>119</td>
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<tr>
<td>Average Price Impact (N/MWh)</td>
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<td>$2.3</td>
<td>$2.3</td>
<td>$2.8</td>
<td>$2.8</td>
<td>$2.8</td>
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<tr>
<td>Average Price Impact per MW of Load Reduction</td>
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<td>$0.01</td>
<td>$0.01</td>
<td>$0.03</td>
<td>$0.03</td>
<td>$0.03</td>
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<tr>
<td>Hours affected</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
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</tr>
<tr>
<td>Average Residual Load (MW)</td>
<td>12,642</td>
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<td>12,642</td>
<td>12,473</td>
<td>12,473</td>
<td>12,473</td>
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<tr>
<td>Annualized % of Residual Load Exposed to Market</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
</tr>
<tr>
<td>Benefit to Exposed Residual Load (million 2007 $)</td>
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<td>$2.6</td>
<td>$2.6</td>
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<td>$5.2</td>
<td>$5.2</td>
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Table 6.2. Estimated Energy Price Impacts in 2013

<table>
<thead>
<tr>
<th>Supply Response Scenario</th>
<th>Immediate</th>
<th>Slower</th>
<th>Delayed</th>
<th>Immediate</th>
<th>Slower</th>
<th>Delayed</th>
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<tr>
<td>Peak Load (MW)</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
<td>13,480</td>
</tr>
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<td>737,505</td>
<td>737,505</td>
<td>737,505</td>
<td>711,144</td>
<td>711,144</td>
<td>711,144</td>
</tr>
<tr>
<td>Jurisdictional Reduction (MW)</td>
<td>570</td>
<td>570</td>
<td>570</td>
<td>1,009</td>
<td>1,009</td>
<td>1,009</td>
</tr>
<tr>
<td>Reductions Not Offset by Supplier Response</td>
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<td>101</td>
<td>101</td>
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<tr>
<td>Average Price Impact (N/MWh)</td>
<td>$2.4</td>
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<td>$2.8</td>
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</tr>
<tr>
<td>Average Price Impact per MW of Load Reduction</td>
<td>$0.036</td>
<td>$0.014</td>
<td>$0.023</td>
<td>$0.03</td>
<td>$0.04</td>
<td>$0.04</td>
</tr>
<tr>
<td>Hours affected</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
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<tr>
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<td>12,292</td>
<td>12,292</td>
<td>11,832</td>
<td>11,832</td>
<td>11,832</td>
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<tr>
<td>Annualized % of Residual Load Exposed to Market</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
</tr>
<tr>
<td>Benefit to Exposed Residual Load (million 2007 $)</td>
<td>$1.4</td>
<td>$4.6</td>
<td>$4.6</td>
<td>$5.5</td>
<td>$12.3</td>
<td>$12.3</td>
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6.4. REAL-TIME PREMIUM

The Brattle-PJM-MADRI study treated all load reductions as if they occurred in the day-ahead timeframe. However, any load reductions that might actually occur in response to real-time (RT) market conditions have more market price impact than load reductions that can only be called in response to day-ahead (DA) market conditions. This is because RT markets are more volatile, with prices spiking when market conditions become unexpectedly tight. Real-time DR can mitigate unexpectedly tight market conditions that offline generators cannot respond to quickly enough.

However, the real-time premium applies only to DR that truly occurs in response to RT market signals, not to amounts already anticipated on a day-ahead basis as part of day-ahead load forecasts or day-ahead price signals. CPP programs would not count as real-time DR if critical periods were designated on a day-ahead basis, as is typical. Only the direct load control programs could provide RT response.

For the real-time DR from direct load control, a value premium over day-ahead DR was estimated by scaling the simulated price difference in a given hour by the ratio of historical super-peak RT prices to super-peak DA prices, based on price-rank of that hour.\(^{35}\) For example,
if a given hour has the second highest price in the simulations from the Brattle-PJM-MADRI study, the ratio of the second highest actual RT price to the second highest actual DA price from the June-September 2005 historical period. This led to factors of approximately 1.15 to 1.3 for the 60 critical hours, which were applied to the direct load control portion of benefits. All of the energy price benefits presented in this report include these factors.

Separately, a potential additional real-time was estimated for a hypothetical case in which CPP is also a real-time program, with critical periods designated day-of. The method for estimating the associated additional value is the same as described above for direct load control, but with a larger number of megawatts. The results of this calculation are presented in tables as a potential additional real-time premium, but they are not included in the net present value calculations.

7.0 SHORT-TERM CAPACITY PRICE IMPACTS

7.1. THEORY

Capacity markets should clear at lower prices in a short-run market equilibrium in which DSM has been introduced but generation suppliers have not yet made countervailing adjustments to their investment and plant retirement decisions. With reduced prices, consumer surplus increases and producer surplus decreases. The associated increase in consumer surplus is what is considered the economic benefit to customers.

In the long-run, the supply side can be expected to adjust to the prospect of depressed returns by accelerating retirements, delaying new construction, and/or submitting higher bids into the capacity market, thus increasing capacity prices and eventually offsetting some or all of the short-term capacity price reduction caused by DSM (DSM does not permanently lower capacity prices any more than building a power plant). As already discussed in Section 6, the time horizon characterizing the “long term” depends primarily on the time it takes suppliers to retire plants early (if there are any plants that can be retired) and to delay new construction (if there are any new projects that can be delayed). This timing is what varies among the Supplier Reaction scenarios.

In the “Immediate Supplier Reaction” and “Slower Supplier Reaction” scenarios, the market is assumed to reach economic equilibrium by 2009. No matter what level of load and DSM-induced load reductions would be expected (and scheduled by PJM into the administratively-determined capacity demand curve), suppliers would offer new capacity at Net CONE. The 3-year forward capacity prices would clear at Net CONE, and just the right amount of capacity would be built. By construction of these equilibrium scenarios, DSM would have no impact on capacity prices.

However, in the “Delayed Supplier Reaction” scenario, the market is assumed to be deficient in capacity and not in equilibrium until 2014. Under scarcity conditions, capacity market prices should be high, and DSM can play an important role in mitigating high prices and improving reliability. The methodology for estimating the capacity price impact in the “Delayed Supplier Reaction” scenario is described below.
7.2. METHODOLOGY

The methodology for simulating capacity prices by the intersection of capacity supply and demand curves case has already been described in Section 5.1.2. Whereas Section 5.1.2. projected capacity prices in order to evaluate the customer benefits from reducing the quantity of capacity they would be required to purchase, this section addresses the likely change in capacity prices due to DSM. Therefore, the key is to simulate the capacity markets with and without DSM and to compare the resulting clearing prices. As the construction of capacity supply and demand curves has already been described in Section 5.1.2 (regarding the projection of capacity prices without DSM), this section describes only how the capacity supply and demand curves (and the clearing price) change when PHI's proposed DSM plans are accounted for.

One key aspect of the RPM is the ability of DR to participate in the capacity market. While only a subset of load reductions under direct control (by the utility, other retail providers, curtailment service providers or the RTO) can participate as supply in capacity markets (e.g., smart thermostats), energy efficiency and the expected effect of CPP programs would also impact capacity prices by reducing the peak load forecast and thus the administratively determined demand for capacity, the Variable Resource Requirement (VRR) curve. Demand resources under direct load control are added to the capacity supply curve at a zero offer bid.

We estimated capacity prices for 2010/11 and 2013/14 delivery years with reduced peak loads (due to PHI's proposed DSM programs) by finding the intersection of the with-DSM supply and VRR curves in the two constrained Locational Delivery Areas (LDA) of PJM, Eastern MAAC LDA and Southwestern MAAC LDA, where all PHI zones are located. The resulting prices were then compared to the (higher) projected capacity prices without DSM.

Customer benefits from short-term capacity price impacts were estimated by multiplying the DSM-induced change in projected capacity prices by the residual UCAP requirement (i.e., with PHI's proposed programs in place).

7.3. RESULTS

For the “Delayed Supplier Reaction” scenario, market clearing capacity prices in the RPM were estimated for the Eastern and Southwestern MAAC LDAs for the delivery years 2010/11 and 2013/14, both with and without PHI-wide implementation of DSM. Figures 7.1, 7.2, 7.3, and 7.4 illustrate the impact of DSM load reductions on the capacity demand and supply curves, and the resulting changes in market clearing prices and capacity. Tables 7.1 and 7.2 below summarize the resulting benefits to customers in the “Delayed Supplier Reaction” scenario. (Recall that capacity prices are assumed to be insensitive to DSM in the “Immediate Supplier Reaction” and “Slower Supplier Reaction” scenarios).
### Table 7.1 - Capacity Market Price Impact of PHI-Wide DSM Implementation in 2010/11

*In the "Delayed Supplier Reaction" Scenario*

<table>
<thead>
<tr>
<th>Locational Delivery Area:</th>
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<th>SWMAAC</th>
<th>EMAAC</th>
<th>SWMAAC</th>
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<tr>
<td>Load Reduction Available from DSM MW</td>
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<td>151</td>
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<td>Capacity Market Price w/o DSM $/MW-day</td>
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<td>190</td>
<td>237</td>
</tr>
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<td>Capacity Market Price with DSM $/MW-day</td>
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<tr>
<td>Change in Capacity Price $/MW-day</td>
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<td>-20</td>
</tr>
<tr>
<td>Capacity Requirement MW</td>
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<td>17098</td>
<td>39518</td>
<td>17098</td>
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<tr>
<td>Annual Customer Benefit ($ millions)</td>
<td>143</td>
<td>66</td>
<td>213</td>
<td>122</td>
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</tbody>
</table>

### Table 7.2 - Capacity Market Price Impact of DSM in Delivery Year 2013/14

*In the "Delayed Supplier Reaction" Scenario*

<table>
<thead>
<tr>
<th>Locational Delivery Area:</th>
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<th>SWMAAC</th>
<th>EMAAC</th>
<th>SWMAAC</th>
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</thead>
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<tr>
<td>Load Reduction Available from DSM MW</td>
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<td>Capacity Requirement MW</td>
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<tr>
<td>Annual Customer Benefit ($ millions)</td>
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</table>
Figure 7.3. Simulated Capacity Auction for SWMAAC in 2010
Delayed Supplier Reaction Scenario with CPP as the Default Rate

Figure 7.4. Simulated Capacity Auction for SWMAAC in 2013
Delayed Supplier Reaction Scenario with CPP as the Default Rate
8.0 OTHER BENEFITS THAT HAVE NOT BEEN QUANTIFIED

In addition to the resource cost savings and short-term market price impacts quantified in this study, reducing peak loads also creates customer benefits by: (1) improving reliability; (2) enhancing market competitiveness; (3) reducing rate volatility; (4) reducing transmission distribution losses; and (5) potentially obviating or delaying the need for investments in transmission and distribution. These categories of benefits have not been quantified either because the economic methodologies involved are not as well developed or standardized and/or because they could not be analyzed within the timeframe allowed for this analysis. These categories of benefits and related environmental issues are discussed qualitatively below.

8.1 RELIABILITY BENEFITS

DSM can reduce the probability and extent of rolling blackouts. With PHI's DSM programs projected to eliminate 1.2% of peak load in Eastern MAAC and 3.6% in Southwestern MAAC in 2013, the reliability benefit could be quite large. In the "Delayed Supply Response" scenario, PHI's DSM programs would increase reserve margins from 11.5% to 12.9% in EMAAC and from 5.8% to 9.9% in SWMAAC. In such a supply-inadequate scenario, DSM would prevent intolerably low reserve margins with likely blackouts and would allow the system to operate reliably. (It is difficult to believe that the utilities would not build capacity as a last resort if such low reserve margins were imminent and if DSM were not available).

Reliability also has economic value. Monetizing reliability benefits require estimating the effect of DSM on the expected loss of load, and then applying an economic value to each megawatt-hour of lost load. Several studies have quantified the value of lost load, finding $1,600 to $4,700 per megawatt-hour for residential customers and $7,000 to $50,000 for small C&I customers, so the economic value of incremental reliability can be quite high.36

The reliability value of DSM has not been captured in any of the capacity-related benefits quantified in this study. Although PJM's capacity market prices in the RPM are partly based on reliability factors, market-clearing prices are capped at 1.5 times the net cost of new entry (Net CONE). Therefore, under extremely tight market conditions, when the value of new capacity is very high from a reliability perspective, the reliability value of demand response load reductions would not be fully reflected in the market clearing capacity prices. For example, in our capacity market simulations, Southwestern MAAC LDA market clearing prices were at the price cap both with and without demand response, and hence no capacity market price effect was projected.

Table 8.1 below suggests that DSM could potentially have a very large reliability value, particularly in a capacity-deficient scenario, such as that represented by the "Delayed Supplier

In such a scenario, PHI’s DSM programs would improve projected reserve margins from 5.8% to 9.9% Southwestern MAAC in 2013.

| Table 8.1. Projected Reserve Margins in the Eastern and Southwestern LDAs |
|---------------------------------|------------------|------------------|
|                                 | SWMAAC LDA 2010 | SWMAAC LDA 2013 | EMAAC LDA 2010 | EMAAC LDA 2013 |
| Internal Supply (UCAP MW) [1]   | 15,583           | 15,583           | 39,309         | 39,309         |
| Coincident Peak Load (MW) [2]   | 15,161           | 15,161           | 33,579         | 35,474         |
| LDA Reliability Requirement [3] | 17,004           | 17,004           | 39,318         | 41,538         |
| DR Load Reduction (MW) [4]      | 541              | 223              | 417            |                |
| Target Reserve Margin [6]       | 18.0%            | 18.0%            | 17.1%          | 17.1%          |
| Existing Capacity              | 15,899           | 15,899           | 37,113         | 37,113         |
| Assumed Cumulative Retirements  | 44               | 218              | 767            | 767            |
| Assumed Cumulative Capacity Additions | 13         | 13               | 304            | 304            |
| Projected Reserve Margin (%)    |                 |                  |                |                |
| Base Case                       | 15.3%            | 5.4%             | 17.1%          | 10.8%          |
| DR Case                         | 15.5%            | 9.3%             | 17.8%          | 12.2%          |
| Projected Reserve Margin (%)    |                 |                  |                |                |
| Base Case                       | 15.2%            | 5.8%             | 18.3%          | 11.5%          |
| DR Case                         | 16.5%            | 9.9%             | 18.5%          | 12.9%          |

1. Based on aggregate supply in 2007/2008 Base Residual Auction (BRA). In future years, new capacity under construction was added, and units scheduled for retirement removed from supply. No generic capacity additions were assumed.
3. Based on RPM parameters published for the 2009/2010 delivery year. In subsequent years, reliability requirement is assumed to increase at the rate of coincident peak load growth.
4. Cumulative load reductions from DSM, adjusted for differences in peak load coincidence.
5. Based on RPM parameters published for the 2009/2010 BRA.
6. Derived from the ratio of the reliability requirement and the coincident peak load forecast.

8.2. MARKET COMPETITIVENESS BENEFITS

During high-load periods, electricity markets suffer from structural problems that increase the incentive and ability for generators to exercise market power. Market power is exacerbated if most customers are not enrolled in DR programs, so they have no incentive to reduce even their lowest-value consumption when spot prices spike to $1,000 per megawatt-hour, leading to a demand curve that is almost completely inelastic. PHI’s proposed DR programs would increase the elasticity of demand and thereby increase the competitiveness of the market. Simple game-theoretic models suggest that doubling the elasticity of demand – not an overly-ambitious goal, given the nascent of DR programs – would enhance competitiveness as effectively as a 50% reduction in market concentration.

Market competitiveness affects market prices for energy and capacity, even with PJM’s market power mitigation measures in effect. PJM’s market power mitigation measures can not possibly eliminate all exercise of market power, nor does it attempt to. Like all RTOs’ market power mitigation protocols, PJM’s attempts to strike a balance between being mitigating market power effectively and being overly stringent. For example, PJM has an agreement with more than 50
new generators installed between 1999 and 2003 not to mitigate their bids at all (except for the $1000/MWh offer cap).

Although there are no well-developed or standardized approaches to quantifying the benefits of enhancing market competitiveness, it is possible to estimate the impact on structural measures of market concentration (e.g., HHI, Pivotal Supplier Index). Furthermore, there are various approaches for translating improvements in these structural measures into potential changes in market prices that have been used in some benefit-cost studies of new transmission. For example, the California ISO estimated competitiveness benefits amounting to 50% to 100% of energy cost benefits for the Devers-Palo Verde 2 and Path 26 Upgrade projects, with a very wide range (5% to 500%) depending on future market conditions.37

A recent study conducted by The Brattle Group analyzing the benefits of a new transmission line in Wisconsin found competitiveness benefits can range from very small to multiples of the production cost savings of the line, depending on (1) market concentration; (2) the nature of market power mitigation; (3) the fraction of load served by cost-of-service generation; and (4) the generation mix and load obligations of market-based suppliers. These findings suggest the competitiveness benefit of adding resources (whether through transmission or DSM) to the energy market could be large in a restructured market such as PJM where little to no load is served by cost-of-service generation.

8.3. INSURANCE BENEFITS / REDUCING RATE VOLATILITY

Many customers are risk-averse and value rate stability, for example because they need to be able to forecast their costs accurately for budgeting purposes. Hence, there is value to reducing the price variance, not just reducing expected prices.

As recent history has demonstrated, retail electricity prices can fluctuate in response to spot prices (for customers on real-time pricing) or in response to expected wholesale prices (for other customers, e.g., those on standard offer service). To the extent that DSM reduces volatility in the spot market, it improves overall electricity price stability for at least some customers. DSM reduces volatility by preventing the market from becoming as tight during normal peaks in load. This mitigating effect is greatest under extreme conditions. Even though this study presents a range of benefits, reflecting a range of market conditions, it does not account for the fact that the greatest benefits occur when rates are highest, when rate relief would be the most valuable. Moreover, there are many possible events that have not been considered in this analysis that could add disproportionately to the overall probability-weighted value of load reductions. Such events include the coincident outages of major generators and transmission lines or an extreme heat wave occurring in shoulder months when many generators are on maintenance. The value of DSM could potentially be quantified more completely by simulating such extreme, low-probability events. The associated reduction in variance could also be valued based on some measure of customer willingness-to-pay to reduce volatility.

8.4. TRANSMISSION AND DISTRIBUTION LOSS BENEFITS

Reducing consumption generally reduces transmission and distribution losses. This is likely to add several percent to the savings that have been quantified, corresponding to the rate of marginal losses on the transmission and distribution systems.

8.5. TRANSMISSION AND DISTRIBUTION INVESTMENT BENEFITS

Reducing peak loads by 3% is comparable to two years of load growth on average and possibly much more in certain locations. In some circumstances, reducing peak loads could enable utilities to delay upgrading distribution transformers and other T&D equipment that is stressed by peak loads. This potential benefit is very location-specific and has not been analyzed in this study.

8.6. ENVIRONMENTAL CONSIDERATIONS

It is possible that demand reductions during critical peak periods achieve modest environmental benefits by reducing generation of the dirtiest plants in non-attainment areas on the hottest, smoggiest days. This effect is difficult to assess because it is very location-specific. In general, the environmental effects of load reductions during critical peak periods are likely to be quite small because the “critical peak” is typically only 60 hours, which is only 0.7% of the year. Reducing demand by 5% during so few hours reduces total generation by less than 0.07%, assuming 50% load factor. Emissions could decrease by an even smaller percentage or increase if responsive load shifts to other hours with different fuels on the margin, or if the customer provides itself with replacement energy using behind-the-meter distributed generation (DG).

Environmental benefits are much greater for energy efficiency than for DR because consumption and generation are reduced in all hours, not just critical peak hours. However, it should be noted that AMI could also help to promote efficiency and conservation. AMI could provide customers with information on their energy usage patterns that enables them to manage and reduce their consumption more actively. For example, in-home displays of hourly usage profiles would enable customers to learn how much energy they are using when they are asleep or away, perhaps prompting them to turn off appliances or discard inefficient refrigerators.

8.7. NON-CRITICAL PERIODS

The study scope also excludes changes in consumption during the non-critical-peak hours because the energy price effects are less pronounced and capacity effects are non-existent in those periods. However, the efficiency component of PHI’s proposed DR programs, and the additional efficiencies and conservation that are likely to result from AMI-based information,

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38 Efficiency is one of the most effective ways to achieve a lower level of emissions. However, under cap-and-trade regulation of emissions, efficiency measures must be accompanied by a tightening of emissions caps, or else the total amount of emissions from all sources will remain unchanged.

54
Table 9.1. NPV of Benefits to Customers through 2029 CPP Default Scenario (million 2007 $'s)

<table>
<thead>
<tr>
<th></th>
<th>DFL DE</th>
<th>DFL MD</th>
<th>FEPCO DE</th>
<th>FEPCO MD</th>
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<td>Immediate</td>
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<tr>
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<tr>
<td>Low Peak</td>
<td>$30,970</td>
<td>$21,350</td>
<td>$7,620</td>
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</tr>
<tr>
<td>High Peak</td>
<td>$30,970</td>
<td>$21,350</td>
<td>$7,620</td>
<td>$30,970</td>
</tr>
</tbody>
</table>

* In the "Immediate" scenario, short-term price impacts last for 1 year. In the "Shorter" scenario, short-term price impacts last for 3 years. In the "Delayed" scenario, suppliers do not build new capacity (beyond projects currently in the queue) and short-term price impacts last through 2013.*

** Excludes potential additional real-time benefit and unquantified benefits.

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Table 9.2. NPV of Benefits to Customers through 2029 CPP Default Scenario (million 2007 $'s)

<table>
<thead>
<tr>
<th></th>
<th>DFL DE</th>
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<td>SHORT-TERM PRICE IMPACTS</td>
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56
### Privileged and Confidential DRAFT

#### Table 1: Resource Cost Savings

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<th>Supplier/Region/Pricing Structure</th>
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#### Table 2: Resource Cost Savings

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Table 9.2. NPV of Benefits to Customers through 2039 CPP Voluntary Scenario (million 2007 $’s)

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* Supplier Risk Scenario: Immediate: short-term price impacts last for 1 year; Slower: short-term price impacts last for 3 years; Delayed: short-term price impacts last through 2033.
** Excludes potential additional real-time benefits and unquantified benefits.

---

59
### RESOURCES COST SAVINGS

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### SHORT-TERM PRICE IMPACTS

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### AVERAGE QUANTIFIED BENEFIT **

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### RESOURCES COST SAVINGS

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### SHORT-TERM PRICE IMPACTS

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APPENDIX

Figure A.1 provides the load reductions that PHI expects from each of the components of its proposed DSM programs other than energy efficiency. (Note that load reductions from the internet-based platform programs have not been included in this figure or in this study because Brattle had incomplete data).

Figure A.1. Projected Peak Load Reductions from Energy Efficiency and Direct Load Control Reductions (MW) by Program Type, 2009-13

Table A.1 provides the net present value of each of PHI's proposed programs just through 2024 and excluding the load reductions from energy efficiency. This table is provided in order to be consistent with the scope of the business plans that PHI has prepared in support of its investments in advanced metering infrastructure (which will enable direct load control and dynamic pricing but not energy efficiency).
### Table A.1: NPV of Benefits to Customers through 2024 CPP Default Scenario (million 2007 $’s)

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* In the "Immediate" scenario, short-term price impacts last for 1 year. In the "Slower" scenario, short-term price impacts last for 3 years. In the "Delayed" scenario, suppliers do not build new capacity (beyond projects currently in the queue) and short-term price impacts last through 2015.

** Excludes potential additional real-time benefit and unquantified benefits.

---

### Table A.2: NPV of Benefits to Customers through 2024 CPP Default Scenario (million 2007 $’s)

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* In the "Immediate" scenario, short-term price impacts last for 1 year. In the "Slower" scenario, short-term price impacts last for 3 years. In the "Delayed" scenario, suppliers do not build new capacity (beyond projects currently in the queue) and short-term price impacts last through 2015.

** Excludes potential additional real-time benefit and unquantified benefits.

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Table A.2. NPV of Benefits to Customers through 2024 CPP Voluntary Scenario (million 2007 $'s)

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* In the "Immediate" scenario, short-term price impacts last for 1 year. In the "Slower" scenario, short-term price impacts last for 3 years. In the "Delayed" scenario, suppliers do not build new capacity beyond projects currently in the queue and short-term price impacts last through 2013.  
** Excludes potential additional real-time benefit and unquantified benefits.
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- **Avoided Capacity Costs**
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- **Avoided Energy Costs**
  - $26
- **Avoided Ancillary Services Costs**
  - $26
- **Short-Term Price Impacts**
  - **Short-Term Energy Price Benefit**
    - $26
  - **Potential Additional Real-Time Benefit**
    - $26
  - **Short-Term Capacity Market Price Benefit**
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**AVERAGE QUANTIFIED BENEFIT**

- **Low Peak**
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- **High Peak**
  - $26

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- **Avoided Energy Costs**
  - $42
- **Avoided Ancillary Services Costs**
  - $9
- **Short-Term Price Impacts**
  - **Short-Term Energy Price Benefit**
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  - **Potential Additional Real-Time Benefit**
    - $42
  - **Short-Term Capacity Market Price Benefit**
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**AVERAGE QUANTIFIED BENEFIT**

- **Low Peak**
  - $174
- **High Peak**
  - $42

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### RESOURCE COST SAVINGS

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### SHORT-TERM PRICE IMPACTS

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### AVERAGE QUANTIFIED BENEFIT **

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</tr>
<tr>
<td>High Peak</td>
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<td>$266</td>
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<td>$327</td>
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</tbody>
</table>
AHMAD FARUQUI
Direct Testimony
D.C. P.S.C. - May, 2009

Introduced as:
PEPCO (C)
Q. WHAT IS YOUR NAME?
A. My name is Ahmad Faruqui. I am a Principal with The Brattle Group (Brattle) located in the firm's San Francisco office.

Q. WHAT ARE YOUR QUALIFICATIONS?
A. I have three decades of research and consulting experience in the design and evaluation of customer-side programs. I am currently leading a state-by-state assessment of the potential for demand response programs for the Federal Energy Regulatory Commission. Last year, I led a national assessment of energy efficiency programs for the Electric Power Research Institute. I also wrote a whitepaper for the Edison Electric Institute on quantifying the benefits of dynamic pricing. During the past few years, I have worked for several utilities, ISOs/ RTOs and state/provincial commissions in assessing the benefits of demand response by designing pilot programs and conducting cost-benefit analyses. I hold a doctoral degree in economics from The University of California at Davis.
Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I want to comment on Potomac Electric Power Company's (Pepco) proposal to deploy an Advanced Metering Infrastructure (AMI) System in the District of Columbia and place its projected benefit estimates in perspective. In my testimony, I draw heavily on a study that Brattle performed for Pepco Holdings Inc. (PHI) in 2007. That study quantified customer benefits from reductions in peak loads during critical times that are likely to be achieved by PHI's proposed demand-side management (DSM) initiatives, including demand reductions resulting from AMI enabled dynamic pricing in its District of Columbia, Delaware, Maryland and New Jersey jurisdictions. The analysis of benefits focused on the top 60 "critical peak" hours in the summers of 2010 and 2013, with interpolations and extrapolations for the years 2009-2029, scaled to the assumed penetration of AMI.

Q. HOW WILL PEPCO'S DEMAND RESPONSE PROGRAMS BENEFIT CUSTOMERS?

A. Pepco's demand response programs will benefit customers by introducing additional demand response into the regional electricity market. The benefits will be of two types. Firstly, they will lower resource costs by reducing the amount of capacity, energy, and ancillary
services that must be bought by Pepco on behalf of its customers. This reduction in resource costs is likely to persist over the long haul. Secondly, Pepco’s programs will depress wholesale market prices for energy and capacity. This second effect is likely to only last for a limited period of time. Additionally, Pepco’s programs can be expected to improve system reliability, enhance market competitiveness by mitigating the market power of generators, reduce price volatility, reduce transmission and distribution losses and possibly obviate or delay the need for investments in transmission and distribution.

Q. AT A HIGH LEVEL, HOW DID YOU ESTIMATE THE DEMAND RESPONSE ASSOCIATED WITH AMI ENABLED DYNAMIC PRICING IN THE DISTRICT OF COLUMBIA?

A. We estimated the impact of dynamic pricing programs in the PHI jurisdictions by adapting the Pricing Impact Simulation Model (PRISM) model to Pepco’s service areas.

We analyzed two alternative dynamic pricing scenarios, both based on the dynamic rates designed for the District of Columbia smart metering pilot program.¹ In the first scenario, customers opt-into a critical-peak pricing (CPP) rate structure. This is assumed to result in a fifth of

¹PowerCentsDC is the smart metering pilot program in the District of Columbia managed by the Smart Meter Pilot Program, Inc. (SMPPP). The pilot is testing three alternative dynamic electricity rates: Critical Peak Pricing, Hourly Pricing, and Critical Peak Rebate. Pricing adjustments are made based upon day ahead PJM sub Zonal PJM hourly market prices.
eligible customers participating. In the second scenario, CPP is made the default rate structure from which the customers can opt out. This results in four-fifths of eligible customers participating.

Q. WHAT AMOUNT OF DEMAND RESPONSE DID YOU ESTIMATE IN THESE TWO SCENARIOS?

A. The demand response in the opt-in scenario is shown in Figure 1 and the demand response in the second scenario is shown in Figure 2. In the opt-in scenario, dynamic pricing is expected to achieve a reduction in peak demand of 22 MW by the year 2013. In the opt-out scenario, the impact rises to 79 MW.

---

2 Eligible customers are assumed to include all residential and small commercial industrial customers that do not already have an interval meter. AMI is expected to provide hourly load data to the utility on a daily basis.
Figure 1. Demand Response in the Opt-In Scenario.

System-Wide Peak Demand Reductions Attributable to Dynamic Pricing
CPP-Voluntary Scenario

![Bar chart showing peak demand reductions over years 2009 to 2013. The values for 2011, 2012, and 2013 are 10, 21, and 22 MW respectively.](chart.png)
Q. HOW DID YOU ESTIMATE THE BENEFITS ASSOCIATED WITH THIS DEMAND RESPONSE?

A. Avoided capacity and energy costs were estimated by multiplying the magnitude of demand response by estimated market prices, which I describe in greater detail below. Market price impacts and their effect on customer costs were estimated by adapting the results of an earlier Brattle study performed for the PJM Interconnection (PJM) and the Mid-Atlantic Distributed Resources Initiative (MADRI). Market price benefits were assumed to diminish over time as suppliers delay new construction and...
accelerate retirements in response to reduced load and market prices.

We considered three scenarios: Immediate Supplier Reaction, Slower Supplier Reaction and Delayed Supplier Reaction. In the “Immediate Supplier Reaction” and “Slower Supplier Reaction” scenarios, the market was assumed to reach economic equilibrium by 2009. Regardless of the magnitude of demand response, suppliers would offer new capacity at the net cost of new entry (CONE). The 3-year forward capacity prices would clear at Net CONE, and just the right amount of capacity would be built. In these two scenarios, DSM would have no impact on capacity prices. However, in the “Delayed Supplier Reaction” scenario, the market is assumed to be deficient in capacity and not reach equilibrium until 2014. Under scarcity conditions, capacity market prices should be high, and demand response can play an important role in mitigating high prices and improving reliability.

Finally, the multi-year stream of benefits was translated into a net present value using the after-tax weighted average cost of capital for each of the PHI jurisdictions.
Q. CAN YOU SUMMARIZE THE ESTIMATED BENEFITS?
A. Figure 3 shows the net present value of benefits to customers in all of PHI’s load zones (including municipal and cooperative utilities contained within the PHI load zones) if in conjunction with energy efficiency and direct load control programs, dynamic pricing were implemented in all of PHI’s jurisdictions.

Figure 3. Net Present Value of Quantified Customer Benefits in all PHI Zones through 2029 (Millions of 2007 Dollars)

Q. HOW DID YOU DERIVE THE SAVINGS IN RESOURCE COSTS?
A. With demand response, Pepco does not need to buy as much capacity as it would the absence of demand response. Nor does it need to buy as much energy during high-priced
periods. Reducing the quantity of capacity and energy that must be produced saves money even if wholesale prices remain unchanged. Customers save commensurately. Assuming a competitive wholesale market, suppliers can be expected to offer capacity and generation based on their costs to serve and to pass changes in their costs onto customers. If the wholesale market is not fully competitive, it is likely that savings would be even greater because demand response enhances market competitiveness.

Capacity savings are estimated by multiplying the projected reduction in physical capacity requirements by the value of physical capacity. The reduction in physical capacity requirements is estimated by assuming that all expected demand response could either supply capacity or reduce the load forecast, thus avoiding the need for physical capacity to the extent that the simultaneous peak load forecast is reduced.

Reducing demand also reduces the amount of energy that must be generated and purchased by customers during high-priced periods. The economic savings depends on the particular type of generation that is being avoided, which could come from a combination of new capacity not constructed and old capacity retired or not dispatched.
It is also partially offset by the value that the consumer forgoes by not consuming as much power.

Q. HOW DID YOU ESTIMATE THE IMPACT OF DYNAMIC PRICING ON PEAK DEMAND?

A. Deployment of AMI will allow PHI to provide dynamic rates to all of its distribution customers. This is expected to yield additional significant reductions in peak demand beyond those that would be achieved through energy efficiency and direct load control programs alone. Specifically, dynamic pricing would allow PHI to provide customers with rates that can be varied in response to situations in which the market price of electricity is high, or in response to conditions that would lead to decreased system reliability, such as unit outages. Dynamic rates typically provide a strong incentive to the customer to reduce demand during a utility-specified "critical peak period." This incentive could be in the form of a higher price during that period (accompanied by a discount during the non-critical hours) or in the form of a rebate for every kWh that is conserved during the critical-peak hours relative to a customer baseline usage level. Either way, the rates are designed to provide peak reductions to the utility when they are needed most, while
at the same time giving the utility's customers the opportunity to achieve bill savings. We relied on our PRISM for predicting the amount of demand response that would result from dynamic pricing. PRISM, originally developed in California, was calibrated to PHI's system characteristics, such as weather conditions, load profiles, saturation of central air conditioning (CAC) and existing rates. With these inputs, PRISM was used to forecast the customer-level peak demand reductions that would occur in response to various PHI-specific dynamic rates. When combined with a forecast of the number of customers participating in the rate, a system-wide forecast of annual peak demand reductions was obtained. Figure 4 summarizes this process.

Figure 4. Forecasting the Financial Benefits of Dynamic Pricing
Q. WHAT IS THE GENEALOGY OF PRISM?

A. PRISM was developed during California's award-winning Statewide Pricing Pilot (SPP). The purpose of the SPP was to measure the change in consumption patterns that customers would exhibit when the structure of their rate was changed from a non-time varying rate to one that was time varying and dynamic, such as critical peak pricing (CPP). The experiment involved over 2,500 residential and small commercial and industrial (C&I) customers served by three investor-owned utilities and spanned a period of more than two years. Ultimately, the SPP produced estimates of customer response to dynamic rates. These estimates varied not only with the dynamic rate design (i.e. price level during the critical peak and off peak periods) but also with information about the region's average load profile, weather, and CAC saturation. It is because of this additional functionality that PRISM's estimations of demand response can reflect not only California-specific conditions, but also be calibrated to provide an estimate of demand response in PHI's service territories.

Inputs to PRISM were developed using data specific to PHI’s service territories. The development of each input and their relevance to the modeling effort are described below.

Q. WHAT DYNAMIC PRICING RATES DID YOU MODEL?

A. Dynamic pricing rate designs include real time pricing (RTP), Peak Time Rebate (PTR, also known as Critical Peak Rebate, or CPR), and CPP. For this analysis, we used the CPP rate that was designed by SMPPI as part of the PowerCentsDC Pilot. This rate was selected because it has already been designed to reflect PJM day-ahead market prices. It can also be used conveniently with PRISM, because the California SPP specifically measured customer response to CPP rates. The all-in CPP from the PowerCentsDC Pilot is illustrated in Figure 5.
The CPP rate would charge customers around $0.83/kWh during critical peak hours, representing a surcharge of $0.70/kWh over the current all-in rate of $0.125/kWh. In return, customers are given a discount of about $0.013/kWh discount during all other hours of the summer (which represent 2,880 hours or over 98 percent of the total hours in the summer).

This CPP rate is designed to be revenue neutral for Pepco's District of Columbia residential customer base. This means that the utility would not gain or lose revenues if all residential customers were enrolled in the CPP rate (in the absence of any changes to consumption patterns).
In other words, the average customer's electric bill would not change if he switched from his current rate to the new CPP rate. Roughly 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). Of course, this is all in the absence of demand response. As customers change load patterns in response to the new CPP rate, a higher percentage will see bill savings.

This CPP rate design was used for residential and small C&I customers in all five of PHI's jurisdictions for analysis purposes. However, because the rate is currently designed to be revenue neutral for Pepco's District of Columbia residential customers, it must be altered to reflect differences in the current rates for customers in other jurisdictions. To do this, both the critical peak rate and the off peak rate were simply scaled up or down using the ratio of the jurisdiction's existing all-in rate relative to that of Pepco District of Columbia. The resulting CPP rates for each jurisdiction and customer type are summarized in Table 1.
Table 1. Summary of CPP Rates ($/kWh)

<table>
<thead>
<tr>
<th></th>
<th>Existing All-in Rates</th>
<th>New CPP Rate</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>All Hours</td>
<td>Critical Peak</td>
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<tr>
<td>Pepco DC</td>
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<tr>
<td>Residential</td>
<td>0.125</td>
<td>0.828</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>0.160</td>
<td>1.055</td>
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<td>Pepco MD</td>
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<td></td>
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<tr>
<td>Residential</td>
<td>0.158</td>
<td>1.041</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>0.147</td>
<td>0.969</td>
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<tr>
<td>Delmarva DE</td>
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<td></td>
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<tr>
<td>Residential</td>
<td>0.143</td>
<td>0.946</td>
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<tr>
<td>C&amp;I</td>
<td>0.115</td>
<td>0.758</td>
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<tr>
<td>Delmarva MD</td>
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<td></td>
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<tr>
<td>Residential</td>
<td>0.145</td>
<td>0.954</td>
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<td>C&amp;I</td>
<td>0.166</td>
<td>1.096</td>
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<tr>
<td>Atlantic City</td>
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<tr>
<td>Residential</td>
<td>0.165</td>
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</tr>
<tr>
<td>C&amp;I</td>
<td>0.183</td>
<td>1.074</td>
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The CPP rate is assumed to be dispatched on 12 critical days during the summer. Since each critical event lasts four hours, this represents a total of 48 critical hours during the summer. During the remaining 2,880 hours of the summer, customers receive the discounted off-peak price. Customers are notified the day before a critical event will be dispatched.

Q. WHAT EXISTING RATES DID YOU USE IN THE PRISM ANALYSIS?

A. The existing rate is a necessary input to the analysis, because a customer's responsiveness to a new CPP rate will be driven by the price increase or decrease that the CPP rate provides relative to the customer's existing rate.

---

4 The analysis of load reductions likely to be achieved by CPP assumes four-hour events, but the benefits component of this study assumes the same level of load reductions would be extended to five hours in order to be consistent with the Brattle-PJM-MADRI study, from which some of the customer benefits are derived.
rate. In other words, during the critical peak hours, a customer is responding not just to the high absolute price level of the CPP, but to the relationship of that price to the existing rate. Similarly, in the off peak, the customer’s response is assumed to be driven by the relative discount that he or she receives through the CPP rate.

Existing all-in rates were calculated for the average residential and C&I customers in all five jurisdictions. For residential customers, the "R" rate schedule for each jurisdiction was used to calculate the average customer’s monthly summer electricity bill. Once the total bill was calculated, it was divided by the monthly consumption to arrive at an all-in rate expressed in dollars per kilowatt-hour.

Table 2. Existing Residential All-In Summer Rates

<table>
<thead>
<tr>
<th>Rate Schedule</th>
<th>PecoDC</th>
<th>PecoMD</th>
<th>DPLMD</th>
<th>DPLDE</th>
<th>ACE</th>
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<tr>
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<td>&quot;R&quot;</td>
<td>&quot;R&quot;</td>
<td>&quot;R&quot;</td>
<td>&quot;RS&quot;</td>
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<tr>
<td>Avg Summer-Bill ($/Month)</td>
<td>132</td>
<td>178</td>
<td>118</td>
<td>133</td>
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<tr>
<td>All-In Rate ($/kWh)</td>
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<td>0.158</td>
<td>0.145</td>
<td>0.143</td>
<td>0.165</td>
</tr>
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Existing C&I rates were calculated in a similar manner. The difference with the C&I customers, as mentioned previously, is that they are spread across
different rate classes. As a means of approximately representing the typical C&I electricity rate, we identified the single rate schedule with the largest share of non-interval metered C&I load and used that rate schedule to calculate the monthly summer bill for the average customer. This bill was divided by monthly consumption to arrive at the existing all-in rate. These rates are summarized in Table 3. for each jurisdiction.

Table 3. Existing C&I All-In Summer Rates

<table>
<thead>
<tr>
<th>Rate Schedule (Jurisdiction)</th>
<th>Avg. Summer Bill ($/Month)</th>
<th>All-In Rate ($/kWh)</th>
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<tr>
<td>&quot;GT LV&quot;</td>
<td>1,469</td>
<td>0.160</td>
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<td>&quot;MGT LV II&quot;</td>
<td>1,303</td>
<td>0.147</td>
</tr>
<tr>
<td>&quot;SGS-S I&quot;</td>
<td>665</td>
<td>0.166</td>
</tr>
<tr>
<td>&quot;MGS-S&quot;</td>
<td>253</td>
<td>0.115</td>
</tr>
<tr>
<td>&quot;MGS-SN&quot;</td>
<td>382</td>
<td>0.163</td>
</tr>
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</table>

Q. USING THESE INPUTS, WHAT MAGNITUDE OF DEMAND RESPONSE DID YOU PROJECT ON A PER-PARTICIPATING CUSTOMER BASIS?

A. The demand response impacts of dynamic pricing on a per-customer basis are summarized in Figure 6 on a percent-of-peak demand basis and in Figure 7 on a nominal kWh/hr basis.

Impacts for C&I customers are estimated to be 30 percent of the impacts for a residential customer on the same rate. In other words, if a residential customer were
to reduce peak demand by 10 percent in response to dynamic pricing, a C&I customer on the same rate would reduce peak demand by 3 percent. This is a conservative estimate that is supported by the findings of the C&I impacts study that was conducted through the California SPP.\(^5\)

**Figure 6. Expected Average Demand Response (Percent of Critical Peak)**

The higher expected peak reduction from Pepco’s Maryland customers (on a percentage basis) can be explained by the higher CAC saturation rate in that jurisdiction. In all jurisdictions, the average residential customer is

expected to produce a greater peak reduction on a percentage basis than that the peak reduction from the average C&I customer. However, this does not always translate into a greater peak reduction on a kWh/hour basis. This depends on the size of the customer. In fact, in three out of the five jurisdictions, the larger size of C&I customers leads to a greater kWh/hour reduction per customer.

Figure 7. Expected Average Demand Response (kWh/hr)

Due to the larger size of C&I customers in Pepco’s jurisdictions, these customers are expected to produce the
largest average peak reductions. Critical peak reductions from other customers range from 0.2 kWh/hr to 0.6 kWh/hr.

Q. HOW DID YOU ESTIMATE THE NUMBER OF PARTICIPATING CUSTOMERS?

A. Customers can only enroll in a dynamic rate if they are equipped with AMI, because this allows their electricity consumption to be measured in hourly intervals (or shorter) as opposed to being measured on a monthly basis. All residential customers will be equipped with AMI. Of the C&I customers, only those without interval meters will be equipped with AMI. The number of eligible customers is summarized in Table 4, along with the annual growth rates that are assumed for each segment of the population.

Table 4. 2006 Customer Population Estimates and Annual Growth Rates

<table>
<thead>
<tr>
<th></th>
<th>Pepco DC</th>
<th>Pepco MD</th>
<th>DPL MD</th>
<th>DE MD</th>
<th>PAE</th>
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</thead>
<tbody>
<tr>
<td>Residential</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>211,220</td>
<td>469,138</td>
<td>169,993</td>
<td>262,684</td>
<td>474,921</td>
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<tr>
<td>Annual Growth Rate</td>
<td>2.0%</td>
<td>0.8%</td>
<td>1.4%</td>
<td>0.9%</td>
<td>1.6%</td>
</tr>
<tr>
<td>C&amp;I</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Non-Interval</td>
<td>24,704</td>
<td>45,248</td>
<td>27,312</td>
<td>32,625</td>
<td>53,096</td>
</tr>
<tr>
<td>Annual Growth Rate</td>
<td>0.9%</td>
<td>0.5%</td>
<td>1.4%</td>
<td>1.3%</td>
<td>1.0%</td>
</tr>
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We assumed that Pepco would deploy AMI to customers over the period from 2009 to 2013. The deployment schedule varies by jurisdiction. It is assumed that customers are

C&I non-interval meter services are used as an approximate representation of the number of eligible C&I customers.
eligible to participate in dynamic pricing once they have
been equipped with AMI. In other words, it is not
necessary for a jurisdiction to achieve 100 percent of its
scheduled deployment before customers can begin enrolling
in the CPP rate. Table 5 below summarizes the AMI
deployment schedule and Figures 8 and 9 combine this with
the population forecasts to show the total number of
customers equipped with AMI in each year from 2009 until
full deployment in 2013.

Table 5. Mid-Year AMI Deployment Schedule (Residential and C&I)

<table>
<thead>
<tr>
<th></th>
<th>Pepco DC</th>
<th>Pepco MD</th>
<th>DPL MD</th>
<th>DPL DE</th>
<th>ACE</th>
</tr>
</thead>
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<tr>
<td>2009</td>
<td>0%</td>
<td>0%</td>
<td>25%</td>
<td>50%</td>
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<tr>
<td>2010</td>
<td>0%</td>
<td>38%</td>
<td>75%</td>
<td>100%</td>
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<tr>
<td>2011</td>
<td>50%</td>
<td>88%</td>
<td>100%</td>
<td>100%</td>
<td>25%</td>
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<td>2012</td>
<td>100%</td>
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<tr>
<td>2013</td>
<td>100%</td>
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</tbody>
</table>
By the end of 2013, over 1.7 million residential customers are expected to be equipped with AMI. Both Pepco Maryland and ACE are anticipated to have deployed AMI to around 500,000 residential customers, accounting for nearly 60 percent of PHI’s total residential deployment.
Figure 9. Forecast of C&I Customers Equipped with AMI

Nearly 200,000 C&I customers will be equipped with AMI in PHI's service territories by the end of 2013. Over 50,000 C&I customers in ACE will be equipped with AMI, representing nearly 30 percent of the total non-interval meter C&I deployment.

Enrollment in the dynamic rate will depend heavily on how the rate is offered to PHI's customers. For example, it could be offered as the default rate, where all customers are put on the dynamic rate with the option of
Witness Faruqui

switching back to their original rate. The expected participation resulting from this type of offering would be much higher than if the dynamic rate were offered on an opt-in basis. There is a significant amount of uncertainty around what enrollment would be like under these various scenarios. Studies have suggested that under the "CPP-Default" scenario, 80 percent of eligible customers could remain on the dynamic tariff. The "CPP-Voluntary" scenario, on the other hand, might lead to only around 20 percent participation in the rate. Due to the wide range of uncertainty surrounding this assumption, we have chosen to analyze the system-wide peak impacts under these two polar scenarios.

These participation rates are not anticipated to be achieved in the first year of the study. In the case of the CPP-Default scenario, enrollment will ramp down from 100 percent in the first year (2009) to 80 percent by 2013. Similarly, for the CPP-Voluntary scenario, participation ramps up from zero to 20 percent by 2013.

It should also be noted that in PHI's service territories, customers have the option of "shopping" for

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7 There are many ways in which customers could be phased into such a rate offering. For example, if all customers were initially placed on the dynamic rate, they could be given full bill protection for the first year of enrollment and this bill protection could be phased out over a three to five year window. This would ensure that customers would understand the potential benefits of the new rate before making a decision on whether to stay on the new rate or switch over to a flat rate.
another retail supplier of electricity. PHI expects that some customers will exercise this option. For the purposes of this analysis, it is assumed that the alternative retail supplier will offer a dynamic pricing scheme similar to the one being modeled, and that the customers who shop around will adopt the dynamic pricing option at the same rate as those customers who do not shop. Due to the fact that the AMI deployment has enabled these customers to enroll in the dynamic rate, their impacts are included in the final estimation of peak demand reductions even though PHI is no longer their supplier.

Customer participation forecasts are summarized in Figure 10 and 11.
Over 1.4 million residential customers are expected to enroll in the dynamic rate by the end of 2013 if it is offered as the default rate. Around 500,000 are expected if it is offered as a voluntary rate.
Over 160,000 C&I customers are expected to enroll in the dynamic rate by 2013 if it is offered as the default rate. Approximately 60,000 are anticipated to enroll if it is offered as a voluntary rate.

Q. WHAT ARE THE SYSTEM-WIDE PEAK DEMAND IMPACTS OF DYNAMIC PRICING?

A. Multiplying the per-customer kWh/hour peak reductions by the forecast of participating customers results in an annual forecast of system-wide peak demand reductions for PHI's service territories. These forecasts are summarized
in Figure 12 for the CPP-Default scenario and Figure 13 for the CPP-Voluntary scenario.

**Figure 12. System-Wide Peak Demand Reductions Attributable to Dynamic Pricing – CPP Default Scenario**

Under the CPP-Default scenario, the total peak reduction attributable to dynamic pricing will be nearly 60 MW in 2009, the first year of AMI deployment. This is expected to grow to over 600 MW by 2013. Nearly 40 percent of the 2013 demand reduction comes from Pepco Maryland.
The CPP-Voluntary scenario provides significantly smaller reductions in peak demand (note the difference in the figure’s y-axis scale compared to the figure showing impacts for the CPP-Default scenario). The expected forecast is for 15 MW of peak reduction in 2009, growing to nearly 180 MW by 2013. By the end of 2013, the peak reductions are less than 30 percent as large as those under the CPP-Default scenario. This is driven by the much lower participation rate.
Q. HOW DID YOU DERIVE THE IMPACT OF PEPCO'S DEMAND REDUCTION PROGRAMS ON PRICES IN WHOLESALE ENERGY AND CAPACITY MARKETS?

A. Even a small reduction in demand during tight market conditions may lower the market price for energy. This lowers the price of energy for all customers, not just those curtailing load, and not just for customers in the zone where DR is implemented. Similarly, reducing the peak demand lowers the demand for capacity, which can lower the market price for capacity, which affects all customers in the same locational delivery area and more broadly throughout the PJM market.

Short-term energy price reductions are estimated by adapting the results of the Brattle-PJM-MADRI study to reflect the differences in load reductions expected from PHI's DSM programs. To the extent that PHI's load reductions differ from the load reductions simulated in the Brattle-PJM-MADRI study, price impacts are estimated using linear extrapolation (e.g., twice the MW of load reductions causes twice the price impact). This linear approach does not consider that the marginal price effect could diminish as load reductions increase. These uncertainties are handled through scenarios, which policy makers can weigh against each other.
As in the Brattle-PJM-MADRI study, the customer benefit from reduced energy prices can be estimated by multiplying the expected price reduction by the quantity of load exposed to market prices. In addition, we have developed an estimate of the capacity price impact from DR.

Capacity price impacts are estimated in the "Immediate Supplier Reaction" and "Slower Supplier Reaction" scenarios by assuming that there is no capacity price impact. In the "Delayed Supplier Reaction" scenario, the market is in a scarcity situation, and high capacity prices are mitigated somewhat by reductions in peak load.

Q. WILL PEPCO'S DEMAND REDUCTION PROGRAMS PRODUCE ANY OTHER BENEFITS?

A. Yes. Other benefits will include (1) improved reliability; (2) enhanced market competitiveness; (3) reduced rate volatility; (4) reduced transmission and distribution losses; and (5) reducing the need for investments in transmission and distribution. Each of these is briefly discussed below.

Reliability Benefits. Demand reduction programs can reduce the probability and extent of rolling blackouts. With PHI's DSM programs projected to eliminate 1.2% of peak

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8 Benefits are partially offset approximately 15 percent by associated reductions in the value of FTRs, as described in the Brattle-PJM-MADRI study.
load in Eastern MAAC and 3.6% in Southwestern MAAC in 2013, the reliability benefit could be quite large. In the “Delayed Supply Response” scenario, PHI’s demand reduction programs would increase reserve margins from 11.5% to 12.9% in EMAAC and from 5.8% to 9.9% in SWMAAC. In such a supply-inadequate scenario, demand response would prevent intolerably low reserve margins with likely blackouts and would allow the system to operate reliably.

Reliability also has economic value. Monetizing reliability benefits require estimating the effect of DSM on the expected loss of load, and then applying an economic value to each megawatt-hour of lost load. Several studies have quantified the value of lost load, finding $1,600 to $4,700 per megawatt-hour for residential customers and $7,000 to $50,000 for small C&I customers, so the economic value of incremental reliability can be quite high.9

The reliability value of demand reduction has not been captured in any of the capacity-related benefits quantified in this study. Although PJM’s capacity market prices in the RPM are partly based on reliability factors, market-clearing prices are capped at 1.5 times the net cost of new

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entry (Net CONE). Therefore, under extremely tight market conditions, when the value of new capacity is very high from a reliability perspective, the reliability value of demand response load reductions would not be fully reflected in the market clearing capacity prices. For example, in our capacity market simulations, Southwestern MAAC LDA market clearing prices were at the price cap both with and without demand response, and hence no capacity market price effect was projected.

Market Competitiveness Benefits. During high-load periods, electricity markets suffer from structural problems that increase the incentive and ability for generators to exercise market power. Market power is exacerbated if most customers are not enrolled in DR programs, so they have no incentive to reduce even their lowest-value consumption when spot prices spike to $1,000 per megawatt-hour, leading to a demand curve that is almost completely inelastic. PHI’s proposed DR programs would increase the elasticity of demand and thereby increase the competitiveness of the market. Simple game-theoretic models suggest that doubling the elasticity of demand – not an overly-ambitious goal, given the nascence of DR programs – would enhance competitiveness as effectively as a 50% reduction in market concentration.
Witness Faruqui

Insurance Benefits/Reducing Rate Volatility. Many customers are risk-averse and value rate stability, for example because they need to be able to forecast their costs accurately for budgeting purposes. Hence, there is value to reducing the price variance, not just reducing expected prices.

As recent history has demonstrated, retail electricity prices can fluctuate in response to spot prices (for customers on real-time pricing) or in response to expected wholesale prices (for other customers, e.g., those on standard offer service). To the extent that demand reduction reduces volatility in the spot market, it improves overall electricity price stability for at least some customers. Demand response reduces volatility by preventing the market from becoming as tight during normal peaks in load. This mitigating effect is greatest under extreme conditions. Even though this analysis presents a range of benefits, reflecting a range of market conditions, it does not account for the fact that the greatest benefits occur when rates are highest, when rate relief would be the most valuable.
Q. HOW DO PEPCO'S PROJECTED IMPACTS AND BENEFITS COMPARE WITH BEST INDUSTRY PRACTICES?

A. In a year-long project for the Federal Energy Regulatory Commission, I have surveyed the projected per-customer impacts of a variety of demand response programs around the country along with projected participation rates. I have also reviewed the history of such programs and contributed to the design and evaluation of such programs over the past three decades for more than fifty utilities and state commissions in the United States and Canada. Finally, I have written case studies of several international programs for the World Bank. In my opinion, the critical-peak pricing program is consistent with best industry practices. It addresses all key market segments and end-uses. Dynamic pricing of course requires the prior deployment of AMI, which is an integral part of Pepco's Blueprint strategy. Once AMI is in place and dynamic pricing has been designed in a manner that appeals to customers and executed with sufficient resources for marketing and implementation, I am confident that the projected impacts will be realized.

Q. WHAT ARE YOUR CONCLUSIONS?

A. I have reached several conclusions. First, Pepco's Blueprint is a comprehensive program, on par with the best
programs in the industry. The Company’s proposed deployment of an AMI System represents an important milestone on the road to the smart grid. Second, the bulk of the program benefits are associated with lowering resource costs associated with the acquisition of capacity and energy. Customer benefits are greatest if dynamic pricing is the default rate structure. Customer benefits would be significant in a supply-adequate market in which suppliers are highly responsive to the introduction of demand response, but they would be much greater in a scarcity situation in which generation supply is static until 2014 (except for projects already in PJM’s queue). If such scarcity were realized, having AMI in place would enable the Public Service Commission to substantially mitigate customer costs by making dynamic pricing the default rate structure.

Third, short-term savings to all customers, including those outside of PHI’s zones, would be much larger because PHI’s load reductions would have a PJM market-wide impact on energy and capacity prices. For example, the total benefits to all of PJM-East are five to eight times greater than the benefits to all customers in the PHI zones.

The customer savings to PHI customers would be nearly twice as large as if all utilities in PJM-East followed
PHI's lead in deploying demand reduction programs and achieved similar load reductions. The aggregate load reductions would create a much greater, market-wide short-term price impact.

Fourth, although CPP programs typically designate peak periods on a day-ahead basis, making the programs callable on a real-time basis (instead of a day-ahead time frame) would enable customers to mitigate the impacts of real-time surprises in load or supply outages.

Fifth, although this analysis does not quantify the reliability benefit in financial terms, we expect the demand reduction programs to materially boost reserve margins in all the areas served by PHI. This insurance value would be of great significance to customers.

Q. ON A NATIONAL LEVEL, COULD YOU BRIEFLY DESCRIBE UTILITY PLANS FOR AMI DEPLOYMENT?

A. Currently, AMI is deployed for five percent of the nation's 142 million customers, up from just one percent just two years ago. Based on current projections, another 40 to 50 million customers will be included by AMI deployments that have already been advanced or at fairly advanced stages of business case development. This additional deployment is expected to take place over the next decade. Deployment may take place at an even faster
pace if appropriate incentives can be provided by the federal government.

Q. COULD YOU BRIEFLY DESCRIBE AMI-ENABLED DYNAMIC PRICING INITIATIVES NATIONALLY?

A. AMI-enabled dynamic pricing is receiving great interest in the United States and Canada. More than a dozen experiments involving several thousand customers have been carried out in these two countries and there is convincing evidence that customers do respond to dynamic pricing by reducing peak loads during critical times. Utilities and state commissions are engaged in serious deliberations about how best to deploy dynamic pricing, once AMI has fallen into place. In California, the Public Utilities Commission has ordered that dynamic pricing should be made the default pricing structure once AMI is deployed (unless it is so prevented by legislation).

Q. IS THERE A "BEST" FORM OF DYNAMIC PRICING?"

A. No. Several AMI-enabled rate designs can accomplish the goal, which is to provide customers an accurate, cost-based price signal that tells them (in near real time conditions) when to conserve energy use in an easy to understand and communicate fashion.
Q. COULD YOU CHARACTERIZE THE PERCENTAGE OF PEAK LOAD
REDUCTIONS THAT HAVE BEEN MEASURED FROM AMI-ENABLED DYNAMIC
PRICING IN OTHER REGIONS OF THE UNITED STATES?

A. Critical peak pricing has achieved load reductions in
the 10 to 20 percent range without enabling technologies
and in the 20 to 50 percent range when accompanied with
enabling technologies. This is based on a review of 15
pricing pilots from around the globe that involved more
than 15,000 customers over the past several years.

Q. SHOULD AMI DEPLOYMENT IN THE DISTRICT OF COLUMBIA BE
DELAYED UNTIL THE SMART CENTS DC PILOT PROGRAM IS
COMPLETED?

A. No. I do not believe that AMI deployment should be
delayed until the PowerCentsDC pilot program has been
completed. There is compelling evidence from pilots in the
US, Canada, Europe and Australia that customers respond to
dynamic pricing by reducing their peak demands. That
evidence is strong enough that it can be used on which to
base the deployment decision. Results from the pilot can
be used to fine-tune the dynamic pricing rates that will be
ultimately offered to Pepco’s customers and to develop
marketing collateral.
Witness Faruqui

1 Q. BASED ON YOUR PROFESSIONAL EXPERIENCE, IS THE DEPLOYMENT OF
2 AN AMI SYSTEM IN THE DISTRICT OF COLUMBIA LIKELY TO BE
3 FINANCIALLY BENEFICIAL TO CUSTOMERS?
4 A. Yes, I would expect that to be the case.
5 Q. DOES THIS CONCLUDE YOUR TESTIMONY?
6 A. Yes, it does.
AFFIDAVIT

City of Washington )
District of Columbia ) ss:

Before me, the undersigned Notary Public in and for the City of Washington, District of Columbia, this day personally appeared Ahmad Faruqui, Principal with the Brattle Group, to me personally known, who stated under oath that the foregoing direct testimony and exhibits were prepared by him or under his direct supervision and control; that he has knowledge of the matters set forth in said direct testimony and exhibits; and that such matters are true and correct to the best of his knowledge, information, and belief.

[Signature]
Ahmad Faruqui

Subscribed and sworn to before me this 21st day May, 2009 in the City of Washington, District of Columbia.

[Signature]
Lisa A. Poole
Notary Public

Lisa A. Poole
Notary Public, District of Columbia
My Commission Expires July 31, 2012
ANTHONY J. KAMERICK
Direct Exhibit

Introduced as:
PEPCO (D)
POTOMAC ELECTRIC POWER COMPANY

BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF ANTHONY J. KAMERICK
FORMAL CASE NO. 1056

Q. PLEASE STATE YOUR NAME AND POSITION.
A. My name is Anthony J. Kamerick. I am Senior Vice President and Chief Regulatory Officer of Pepco Holdings, Inc. (PHI). I am testifying on behalf of Potomac Electric Power Company (Pepco or the Company).

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR ROLE AS SENIOR VICE PRESIDENT AND CHIEF REGULATORY OFFICER?
A. I am responsible for all regulatory matters related to PHI and its three regulated utility subsidiaries, including Pepco. I am also the senior officer responsible for regulatory matters that come before the Federal Energy Regulatory Commission. Prior to my election as Chief Regulatory Officer, I was Vice President and Treasurer of PHI, with responsibility for managing PHI's relationship with the financial community, including being the primary contact with credit rating agencies.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE?
A. I hold a Bachelor of Science degree in Accounting from the University of Maryland and a Master of Business Administration, with a concentration in Finance and
Investment from George Washington University. I have also
successfully completed the University of Michigan’s
Public Utility Executive Program.

I joined Pepco in 1970 and have served in various
positions of increasing responsibility, including
Manager, Revenue Requirements and Director, Budgets and
Financial Planning. In 1982, I was elected Assistant
Treasurer of the Company and in 1983, I was elected
Assistant Comptroller. From 1985 through February 1988, I
served as Treasurer of Pepco’s then-principal subsidiary,
Potomac Capital Investment Corporation (PCI). I was
elected Vice President and Treasurer of PCI in September
1986. I was reassigned to Pepco and elected Assistant
Comptroller in March 1988, and elected Comptroller in
April 1992. In May of 1994, I was elected Vice President
and Treasurer of Pepco. Following Pepco’s merger with
Conectiv, and the formation of Pepco Holdings, Inc. as
the parent of Pepco and Conectiv in August 2002, I was
elected to the additional position of Vice President and
Treasurer of PHI. In March 2009, I was promoted to Senior
Vice President and Chief Regulatory Officer.

I am a member of the District of Columbia Chapter of
Financial Executives International and a past President
of the Chapter and Board member. In addition, I am a
Witness Kamerick

member of the National Association of Rate of Return Analysts and the Council of Corporate Treasurers, and a former member of the Edison Electric Institute Accounting Research Committee and the Budget and Financial Forecasting Committee. I serve on the Board of Directors of Montgomery Alliance for Community Giving and also serve on the Board of Directors of the Community Services for Autistic Adults and Children Foundation.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the cost recovery mechanism the Company seeks for expenditures related to its Advanced Metering Infrastructure (AMI) program. Additionally, I will discuss the financial implications of undertaking a project of this program's magnitude, including the challenges of financing major projects in the current financial markets, the importance to the financial community of cost recovery, and the Company's need to maintain strong credit quality in light of the turmoil in the financial markets.

This testimony was prepared by me or under my direct supervision. The source documents for my testimony are Company records, public documents, and my personal knowledge and expertise.
Q. PLEASE SUMMARIZE THE PROPOSED RECOVERY MECHANISM FOR AMI AND ITS IMPORTANCE.

A. On April 2, 2009, in Formal Case Nos. 945 and 1056, the Company filed with the Commission a motion to expedite the proposed implementation of AMI; included in that motion was a request to establish a regulatory asset in which to defer recognition of incremental costs associated with the AMI deployment that are incurred between rate cases. The creation of a regulatory asset is necessary to afford Pepco the opportunity to recover prudently incurred costs associated with the deployment of AMI. It also preserves the ability of Commission Staff and other interested parties to review the prudency of those costs when Pepco seeks to recover them.

Additionally, as discussed by Company Witness Gausman, Commission authorization of AMI deployment and approval of regulatory asset treatment would better position the Company in its efforts to obtain federal funding for AMI pursuant to the recently enacted American Recovery and Reinvestment Act (ARRA) of 2009. In a recently filed Notice of Intent (NOI) to Issue a Funding Opportunity Announcement, the Department of Energy (DOE) had in its list of items to be included on any applications "An identification of decisions requiring
external approval, e.g., the allowance of investment
expenditures by Public Utility Commissions or other
authorities" (item e., page 10, DOE NOI to Issue a
Funding Opportunity Announcement for the Smart Grid
Investment Grant Program). Later in that document, DOE
noted that additional merit would be given to
applications that "offer the greatest extent of
institutional and organizational commitment with
consideration given to ...required approvals from
regulatory organizations" (item e, part iii, page 13, DOE
NOI to Issue a Funding Opportunity Announcement for the
Smart Grid Investment Grant Program). Clearly, DOE
recognizes that lack of advance Commission approval
increases the risk associated with the project coming to
fruition, and thus makes it less likely to receive DOE
funding.

Q. HAS FERC INITIATED ANY COMMENTARY REGARDING SMART GRID
INVESTMENTS MADE IN CONJUNCTION WITH DOE FUNDED PROJECTS?

A. Yes. On May 19, 2009, FERC issued a Notice
Requesting Supplemental Comments for its Proposed Smart
At page 4 of that document, FERC noted that, "While
the Notice of Intent does not specifically require that
an applying electric utility get approval from a
regulatory commission for non-Federal funds, the document could be read as indicating a preference for such approval." Based on its understanding that DOE may give preference to those applications that have already received final or conditional approval from their regulatory authorities for recovery of cost associated with these DOE projects, FERC is seeking comments on how they should address requests for rate recovery on such FERC jurisdictional projects.

Q. HAS THE COMPANY INCURRED ANY COSTS RELATED TO AMI DEPLOYMENT TO DATE?

A. Yes. Through December 31, 2008, Pepco has incurred $911,000, on a District of Columbia jurisdictional basis, related to initial infrastructure development efforts necessary to support the AMI initiative. In its next base rate case, to be filed in the second quarter of 2009, the Company will propose these early developmental costs be amortized over a three-year period, with the unamortized balance in rate base. To avoid confusion between proceedings, I recommend review and recovery of those initial expenditures remain as part of the base rate case, and that the subject of this proceeding be only post-December 31, 2008 expenditures.
Q. PLEASE DESCRIBE HOW COSTS AND SAVINGS ASSOCIATED WITH AMI DEPLOYMENT WILL BE REFLECTED IN THE FINANCIAL RECORDS OF THE COMPANY.

A. As the new AMI meters go into service, they will be recorded in Electric Plant In Service (EPIS), and will begin being depreciated at the Commission-approved rate. Similarly, once the Meter Data Management System becomes operational, its cost will be recorded in Intangible Plant and amortized over the standard five-year software amortization period. As time passes, and the savings resulting from AMI deployment, such as in the area of meter reading, as discussed in the testimony of Company Witness Potts begin to inure, Operations and Maintenance (O&M) expense will be lower than it otherwise would have been, absent AMI deployment.

Q. PLEASE DISCUSS WHY ESTABLISHMENT OF A REGULATORY ASSET IS APPROPRIATE FOR POST-DECEMBER 31, 2008 EXPENDITURES AND SAVINGS IS NECESSARY.

A. As noted above, as AMI is deployed, EPIS, depreciation and amortization expenses, and O&M savings resulting from AMI are going to be reflected in the financial records of the Company. They will not, however, be reflected in the Company’s distribution base rates. Thus, I propose that costs incurred after
December 31, 2008 for the implementation of AMI in the District of Columbia, including incremental labor costs, lease expense, depreciation, and amortization, be deferred in a new AMI Regulatory Asset. Any known and measurable utility cost savings resulting from AMI deployment will also be reflected as an offset in the regulatory asset. The balance in the regulatory asset will accrue a return based on the Company’s most recently authorized rate of return. The deferred amounts will be reviewed in the context of the Company’s next base rate proceeding, and upon Commission approval, be recovered over an appropriate period of time, such as three to five years.

The AMI costs discussed by Company Witness Potts represent a significant capital commitment for Pepco. Without conceptual AMI deployment authorization and regulatory asset accounting, Pepco risks non-recovery of significant investments in the deployment of its Meter Data Management System and AMI meters. This is a financial risk that the Company is unable to assume, particularly in today’s economic climate.
Q. ARE YOU RECOMMENDING ACCRUAL OF A RETURN ON THE ASSETS
    THAT ARE REFLECTED IN EPIS IN THE FINANCIAL RECORDS OF
    THE COMPANY BUT THAT ARE NOT YET REFLECTED IN BASE RATES?
A. No. We are requesting a return at the authorized
    rate only on the net expenses and savings reflected in
    the regulatory asset.
Q. PLEASE DISCUSS YOUR PROPOSED TREATMENT OF THE EXISTING
    METERS THAT WILL BE REPLACED BEFORE BEING FULLY
    DEPRECIATED.
A. As noted in both the Company’s original application
    and in the Business Case, the deployment of AMI will
    require removal and disposition of existing meters that
    are not fully depreciated. The net book value of
    District of Columbia meters at December 31, 2008 was
    $51.0 million. This amount represents costs that were
    prudently incurred, and which need to be recovered. When
    the new meters are installed, the old meters will be
    retired from EPIS, and any undepreciated amount should be
    moved to a regulatory asset to be amortized over a future
    period. We recommend a period of fifteen years, because
    that is the expected useful life of the new meters noted
    by John Spanos, of Gannet-Fleming, in his District of
    Columbia depreciation study filed with the Commission in
    December 2008. This is a conservative approach; for
example, Florida Power and Light recently requested recovery over a four-year period of their regulatory asset associated with meters replaced by AMI meters.

Q. PLEASE DISCUSS PEPCO’S OVERALL FINANCING REQUIREMENTS.

A. Pepco has and will continue to have needs for access to large amounts of capital to meet its responsibilities to customers in these rapidly changing times. In the past, Pepco’s largest capital needs, like those of other utilities, would have been associated with maintaining, replacing and upgrading the poles, wires and related equipment that make up the basic transmission and distribution (T&D) system. However, the current environment requires far more of T&D utilities like Pepco. We also need to invest in new smart grid technologies which will give our customers more stable energy costs, responsive customer service, greater power reliability, and more environmentally-friendly programs that help reduce the use of natural resources. These goals are embraced in the Company’s Blueprint for the Future (Blueprint) and are supported by the District of Columbia and Federal policies.

For Pepco to have access to the capital necessary for investments both in its basic T&D infrastructure as well as in new technologies, it must maintain its
financial integrity, as reflected in its rate of return on equity, credit ratings and other key financial metrics. Financial integrity has always been important to utilities, and is even more so now, with the ongoing crisis in world credit markets. Sources of capital traditionally available to Pepco have become more costly, far more difficult to access, and in some cases unavailable at any price. Favorable rulings from the Commission, such as facilitation of recovery of prudently incurred costs and approval of regulatory asset treatment before recovery, are crucial to providing the Company the level of financial integrity necessary for access to needed capital on reasonable terms.

Q. HOW HAS THE RECENT FINANCIAL MARKET CRISIS AFFECTED THE COMPANY?

A. The crisis has heightened the importance of maintaining the financial integrity of the Company, as reflected in its credit ratings. Investment Grade ratings have always been important. They allow access to capital on reasonable terms for utilities, which are capital-intensive and have a legal obligation to provide reliable service in both good economic times and bad. Investment Grade ratings take on added importance in times like these, when capital markets have been nearly
frozen at times, and a deterioration of the Company's
credit quality to below Investment Grade can mean not
just higher costs of borrowing, but the inability at any
time to raise capital on any terms.

Q. PLEASE ELABORATE ON YOUR POINT CONCERNING THE COMPANY'S
ABILITY TO RAISE CAPITAL.

A. The U.S. and global financial sectors are
experiencing systematic and structural weaknesses. As a
result, the capital markets have functioned very
erratically since about September 2008. Recently, utility
stocks were trading at 52-week lows, and in many cases,
below book value; in fact, Pepco's stock is currently
trading at approximately 50% of book value. The
commercial paper market remains severely constrained; and
banks were, and to this day still are, reluctant to
extend credit as easily and as inexpensively as they have
in recent years.

What this means is that even Investment Grade
companies have experienced difficulties securing
financing on reasonable terms, and access to the capital
market over the past several months has been very
inconsistent. Even on days when the capital market is
somewhat receptive to new debt issues, credit spreads
(the difference between interest rates on corporate debt
Witness Kamerick

and U.S. treasury securities) are at historically high
levels.

Q. PLEASE DISCUSS THE COMPANY'S DEBT RATINGS BY MAJOR RATING
AGENCIES.

A. As I mentioned above, Pepco's short term credit
ratings are A2/P2 from S&P and Moody's. The Company's
senior, secured long-term debt ratings are BBB+ and Baal
from S&P and Moody's, respectively. These senior,
secured long-term debt ratings are on the lower end of
the Investment Grade rating scale. The highest long-term
Investment Grade debt rating awarded by the rating
agencies is triple A and the lowest is triple B-.

Q. DOES THE REGULATORY ENVIRONMENT AFFECT PHI'S CREDIT
RATINGS?

A. Yes, it is a very important factor. In fact, in a
Standard & Poor's publications entitled "Assessing U.S.
Regulatory Environments," dated November 7, 2008, and
"Business and Financial Risks in the Investor-Owned
that the regulatory climate is perhaps the most important
factor it analyzes when evaluating investor-owned
utilities. It noted that regulatory risk will continue
to be evaluated based on the environments in which
companies operate, as well as other factors, including
ratemaking practices and procedures, cash flow support and stability, political insulation, operating performance, credit metrics, and particularly cash flow metrics.

Q. PLEASE DISCUSS STANDARD & POOR'S ASSESSMENT OF REGULATORY RISK.

A. The S&P credit committee uses its "assessments" as the starting point for evaluation of a utility's regulatory risk. Its goal is to ascertain, purely from a credit perspective, the "posture of a jurisdiction's policymakers" on issues that are relevant to utilities' creditors. Essentially, it is evaluating financial stability factors, such as rate design and rate treatment of large capital expenditures; ratemaking factors, such as cost recovery, ratemaking timeliness and non-traditional ratemaking practices; and regulatory/political factors, such as the degree of political interference in the regulatory process, the independence of the Commissioners, and the selection process for Commissioners. S&P's evaluation of regulatory risk include:

i. Consistency and predictability of decisions;

ii. Support for recovery of fuel (energy in our case) and investment costs;
iii. History of timely and consistent rate
treatment, permitting satisfactory profit
margins and timely return on investments; and
iv. Support for cash return on investments.

For a regulatory process to be considered supportive
of credit quality, it must limit uncertainty in the
recovery of utilities' investments. It must also
eliminate, or at least reduce, rate case lag, especially
when the utility engages in a sizeable capital
expenditure program.

Q. WHAT WAS S&P'S VIEW OF THE JURISDICTIONS IN WHICH PHI
OPERATES?

A. PHI operates in four jurisdictions - the District of
Columbia, Maryland, Delaware and New Jersey. Each
jurisdiction is distinct and has its own set of unique
regulatory, financial and legislative characteristics.

S&P has established five categories from which to
make its assessment of regulatory risk - from "Most
Credit Supportive" to "Least Credit Supportive," with
intermediate categories of "More Credit Supportive,"
"Credit Supportive," and "Less Credit Supportive."

Currently, there are no U.S. jurisdictions that S&P
considers to be in the top category of "Most Credit
Supportive." New Jersey was viewed as "Credit
actions in sufficient time to facilitate Pepco's being competitive in the quest for that grant money would also be positively perceived.

Q. BRIEFLY SUMMARIZE THE COMPANY'S OVERALL FINANCIAL CONDITION IN LIGHT OF THE ECONOMIC CRISIS, AND THE IMPLICATIONS OF THAT FOR AMI DEPLOYMENT.

A. While the Company is currently meeting its financial needs, it will require continued regulatory support to weather the ongoing financial crisis. The Company has recently taken a number of steps to solidify its financial condition. We have prudently issued debt, commercial paper and common stock, all designed to increase capital, credit capacity and eliminate refinancing risks. However, to maintain the financial integrity required in today's economic climate, it is imperative the Company have the support of the Commission, through authorization of AMI deployment and approval of regulatory asset treatment, before undertaking a project of the magnitude of AMI.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.
AFFIDAVIT

City of Washington   )
District of Columbia  )   ss:

Before me, the undersigned Notary Public in and for the City of Washington, District of Columbia, this day personally appeared Anthony J. Kamerick, Senior Vice President and Chief Regulatory Officer - PHI Service Company, to me personally known, who stated under oath that the foregoing direct testimony was prepared by him or under his direct supervision and control; that he has knowledge of the matters set forth in said direct testimony; and that such matters are true and correct to the best of his knowledge, information, and belief.

Subscribed and sworn to before me this 21st day of May, 2009 in the City of Washington, District of Columbia.

[Signature]
Notary Public

My Commission expires  July 31, 2012