atlantic city electric

A PHI Company

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August 1, 2008

VIA OVERNIGHT COURIER AND ELECTRONIC MAIL

Kristi Izzo
Secretary of the Board
State of New Jersey
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

RE: In the Matter of Atlantic City Electric Company's Responsive Petition to the Board of Public Utilities Order Dated July 1, 2008 Regarding the Submission of Demand Response Programs for the Period Beginning June 1, 2009 for Electric Distribution Companies, and for Supplemental Inclusion of Same in Its "Blueprint for the Future" Filing Dated November, 19, 2007
Docket Nos. EO08050326 and EO07110881

In the Matter of the Demand Response Programs for the Period Beginning June 1, 2009 – Electric Distribution Company Programs
BPU Docket No. EO08050326

Dear Secretary Izzo:

Enclosed please find an original and eleven (11) copies of the Verified Petition of Atlantic City Electric Company ("ACE" or the "Company") and attachments in support of the Petition. A disk containing a PDF of the filing has also been provided. Please return a "filed" and docketed copy of the Petition to the Company in the enclosed self-addressed, postage-paid envelope.

This filing is being made pursuant to an Order of the Board dated July 1, 2008 (the "Order") and seeks Board approval by no later than November 2008 for (i) implementation of ACE's proposed demand response programs as filed and (ii) recovery of associated program costs with adjustments on January 1st of each year through an annual reconciliation/cost recovery filing. This is consistent with N.J.S.A. 48:3-98.1(a)(3), which was invoked by the Board in the Order.

The Company notes that programs similar to those proposed in the instant filing were filed in the context of ACE's November 2007 filing entitled "In the Matter of Atlantic City Electric Company's 'Blueprint for the Future,' Establishing an Advanced Metering Infrastructure Program, Demand-Side Management Initiatives, Utility-Provided Demand Response Programs and Other Programs, and Requesting BPU Approval of Cost Recovery Mechanisms Related Thereto," BPU Docket No. EO07110881 (the "Blueprint Filing").

As stated by Kenneth J. Parker, the President of the Atlantic City Electric Region, in his November 19, 2007 letter to the Board, the Blueprint for the Future is

> an ambitious, multi-faceted proposal for investing in innovative technologies and forward-thinking initiatives that will help the Company's customers manage their energy use more effectively, reduce the total cost of energy, protect the environment by reducing greenhouse gas emissions, and enhance ACE's overall system reliability. The Blueprint will also assist the State in meeting the ambitious goals set by the Energy Master Plan.

Inasmuch as the requirements of the instant filing are in harmony with the goals of the Blueprint Filing, ACE has also requested that the Board incorporate into the record of this proceeding "all relevant material and data" as contained in the record of the Blueprint Filing. The Company also respectfully requests that the Board "supplement the record in the Blueprint [F]iling with this Petition and all additional relevant material and data to be developed herein."

Atlantic City Electric Company looks forward to working with the Board and all interested stakeholders to bring these ideas and proposals to fruition.

Respectfully submitted,

Passanante

Philip J. Passanante
An Attorney at Law of the
State of New Jersey

Enclosures

cc: Service List

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU Docket Nos. EO08050326 and EO07110881 VERIFIED PETITION

ATLANTIC CITY ELECTRIC COMPANY (hereinafter referred to as "Petitioner," "Atlantic" or the "Company"), a public utility corporation of the State of New Jersey (the "State"), respectfully requests that the Board of Public Utilities ("BPU" or the "Board") accept this Petition as the Company's response to the Board's Order dated July 1, 2008 in Docket. No. EO08050326 with respect to its proposal for demand response programs designed to be implemented by June 2009 to reduce electricity demands on its system during periods of high electricity demand and high electric market prices. The Company hereby seeks approval by the Board of the proposed implementation authorizations and cost recovery mechanisms contained herein, and seeks to initiate and supplement these components of the Company's "Blueprint for the Future" (referred to herein as the "Blueprint" or the "Plan") filing in Docket. No. EO07110881 as modified herein. In support thereof, Petitioner states as follows:

1. The Company is engaged in the purchase, transmission, distribution and sale of electric energy to residential, commercial and industrial customers. ACE's

service territory comprises eight (8) counties located in southern New Jersey and includes approximately 544,000 customers.[1]

2. In an effort to further the articulated goals of the New Jersey Energy Master Plan (herein, the "EMP") and assist the Board and the State in achieving their multi-faceted energy priorities, the Company, in November, 2007 filed with the Board the Blueprint, which, among other component programs such as Advanced Metering and Energy Efficiency, contained comprehensive Demand Response programs for the Company's New Jersey customers. The instant filing not only responds to the Board's July 1, 2008 Order, but also supplements the provisions of the Blueprint that relate to the Demand Response component of the Plan.

3. Petitioner seeks the cost recovery authorizations requested herein to enable the Company to commit the necessary financial resources to make its proposed Demand Response program a reality for ACE's New Jersey customers. As described in summary fashion below, Atlantic is seeking authorization to recover program costs for the Demand Response program proposed herein through the existing System Control Charge ("SCC") across all electric distribution customers as more fully described in the direct testimony of Joseph F. Janocha submitted herewith and made a part hereof as **Exhibit A**.

4. As more fully described in the direct testimony of Stephen L. Sunderhauf, attached hereto as **Exhibit B**, Atlantic's proposed Demand Response programs are

[1] ACE is part of the Pepco Holdings, Inc. ("PHI") family of companies. It is a wholly-owned subsidiary of Conectiv, a Delaware corporation, which is, in turn, a wholly-owned subsidiary of PHI, a Delaware corporation. PHI is an energy holding company engaged in regulated utility operations and sale of competitive energy products and services to residential and commercial customers. PHI companies deliver electricity and natural gas to more than 1.8 million customers in Delaware, the District of Columbia, Maryland, and New Jersey.

designed to allow the Company to better manage the electricity usage of its customers during periods of high market prices, with the goal of reducing that demand during such periods.

As the Company noted when it filed its Blueprint, a recent study prepared by The Brattle Group, a copy of which is attached hereto as **Exhibit C**, and commissioned by the Mid-Atlantic Distributed Resources Initiative (“MADRI”) and the PJM Interconnection, LLC, found that a modest reduction in electricity use during peak hours would reduce energy prices by $57 million to $182 million annually in the mid-Atlantic region. The study examined the effects of reducing electricity use during periods of peak pricing and underscores the importance of demand response to New Jersey and provides further support for the authorizations requested by the Company in this filing.

This Petition respectfully requests Board authorization pursuant to its legislative authority to implement the Demand Response programs and expand existing surcharges as detailed herein and in the testimonies submitted herewith, that will enable the Company to implement the BPU’s objectives for Demand Response programs in the Company’s service territory and allow for the recovery of future costs of these initiatives, programs and proposals. Such authorization will provide necessary assurances to the investment community that costs incurred in developing and executing them will be fully recovered in a timely manner through appropriate mechanisms.

DEMAND RESPONSE PROGRAMS OVERVIEW AND SUMMARY

Petitioner's proposed Demand Response programs involve an initial investment over a five year period in excess of $16 million in the design and implementation of the programs. Although the Company provides details on the components of the proposed programs in **Exhibit B**, a brief summary of each of the programs features and benefits is included below.

Demand Response Programs

5. Petitioner proposes the implementation of two Demand Response programs: (a) a residential controllable smart thermostat program to permit the utility to reduce summer air conditioner and heat pump load during peak periods of electricity usage, and (b) an Internet-based demand response platform to support larger-size customer participation in the PJM demand response program.

These programs, coupled with appropriate investments in technology, will provide the tools for Petitioner's residential and non-residential electric distribution customers to manage their electricity usage and, in turn, costs. More detail, including cost estimates and cost benefit analyses, is provided in **Exhibit B**.

Cost Recovery Mechanisms

6. Petitioner's Demand Response programs have been designed to provide real and substantial benefits to Atlantic's New Jersey customers and to assist the Board and the State in achieving the goal of reducing electricity demand at peak pricing times. As noted in Mr. Sunderhauf's direct testimony, the net cost benefit from the smart thermostat program alone is in excess of $40 million. To implement these programs and achieve the desired benefits, Atlantic will be required to make significant capital and

financial commitments. Such commitments require companies, regulators and other interested parties to implement appropriate regulatory and cost recovery approaches.

To facilitate the timely cost recovery of prudently incurred Demand Response expenditures and provide adequate cash flow for the deployment of future new technologies and innovative programs, Petitioner has proposed a cost recovery mechanism that will allow the Company to recover Demand Response program costs through the existing SCC, as more fully described in **Exhibit A**.

Timing

7. Petitioner recognizes the aggressive timetable that the Board has laid out for completion of the regulatory review process for its, as well as the other electric distribution company programs in the State being filed simultaneously herewith, to meet the demand response initiatives as set forth in the Board's July 1, 2008 Order. The Company is committed to working in close accord with Board's Staff and the Division of Rate Counsel, as well as other affected utilities and stakeholders, to complete the regulatory review process and have a Board Order in place in sufficient time to meet the June 2009 implementation date.

Atlantic must offer a word of caution, however. Any delay beyond November 2008 in the issuance of a final, non-appealable Board Order could seriously jeopardize the Company's ability to meet the June 2009 implementation date. Given the shortness of time associated with the aforementioned timetable, it is unlikely that the Company can achieve significantly greater reductions in peak demand during each year of the program. However, the Company's plan is expected to achieve more than a 50MW reduction in demand by 2013, which is consistent with the demand reductions recommended by

Summit Blue Consulting ("Summit Blue") for a residential smart thermostat program in its service territory, and an additional 10MW reduction resulting from the Internet-based demand response platform program for non-residential customers.

As noted in the direct testimony of Mr. Sunderhauf, the Company's objective in developing its demand response programs is to obtain the maximum MW reduction levels achievable based upon the most reliable data available to it. For that reason, the Company elected for its residential controllable smart thermostat program to utilize the analysis and conclusions reached by the Summit Blue report, rather than rely upon expected participation levels that may or may not be achievable. Petitioner believes that its reliance on such verifiable data is consistent with the Board's intent and directive as set forth in ordering paragraph 2 of the "EDC Approach" in the Order. To the extent that further "review and comment" can provide a sound basis for further enhancing the Company's program participation, the Petitioner is open to having those discussions.

8. Petitioner's Blueprint has been before the Board since November 2007. It contains certain program elements similar to, if not the same as, those proposed in this instant filing. In that regard, over the course of the past eight months, there has been a significant amount of discovery by the parties to the Blueprint that are applicable to these proposed Demand Response programs. In the interest of regulatory efficiency and to avoid unnecessary duplication of effort, and given the shortness of time available to the Board for consideration of Atlantic's programs, the Company believes it is appropriate to incorporate those portions of the Blueprint record into this proceeding that bear upon this Petition. Similarly, the Company believes it appropriate to supplement the record in its

Blueprint proceeding with this filing, as well as any additional and new discovery that may be generated with respect hereto.

9. Attached hereto and made a part hereof as **Exhibit D,** along with related **Attachments 1** through **6,** is Atlantic's submission with respect to the filing requirements set forth in N.J.S.A. 48:3-98.1 as same are applicable to this instant Petition.

10. Communications and correspondence regarding this matter should be sent to Petitioner's counsel and co-counsel at the following addresses:

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with copies to the following representatives of the Company:

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WHEREFORE, the Petitioner, **ATLANTIC CITY ELECTRIC COMPANY**, respectfully requests that the Board of Public Utilities issue an Order as follows:

A. **Approving** the implementation of Petitioner's proposed Demand Response programs as filed, and further **approve** the recovery of associated program costs through the existing SCC, as outlined in the Petition and related pre-filed direct testimony, with adjustments on January 1st of each year through an annual reconciliation/cost recovery filing, and

B. **Approving** the incorporation in the record hereof of all relevant material and data as contained in the record in the Company's Blueprint filing, and to supplement the record in the Blueprint filing with this Petition and all additional relevant material and data to be developed herein.

C. Lastly, Petitioner respectfully requests that the Board issue its Order in this regard no later than November, 2008 for program implementation by June, 2009, and further **approve** the stated MW reductions per program year as identified in **Exhibit B** attached to this Petition.

Respectfully submitted,
ATLANTIC CITY ELECTRIC COMPANY

Dated: August 1, 2008

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STATE OF NEW CASTLE)
)SS:
COUNTY OF DELAWARE)

AFFIDAVIT OF VERIFICATION

J. MACK WATHEN, being duly sworn, upon his oath, deposes and says:

1. I am the Vice President of Regulatory Affairs of Atlantic City Electric Company ("ACE"), the Petitioner named in the foregoing Verified Petition, and I am duly authorized to make this Affidavit of Verification on ACE's behalf.

2. I have read the contents of the foregoing Verified Petition. I verify that the statements of fact and other information contained therein are true and correct to the best of my knowledge, information and belief.

J. Mack Wathen

J. MACK WATHEN

SWORN TO AND SUBSCRIBED before me this 31st day of July, 2008.

Julia R. Swintek/Reilly

Julia R. Swintek/Reilly
Notary Public
My Commission Expires: April 30, 2009

JULIA R. SWINTEK/REILLY
NOTARY PUBLIC
STATE OF DELAWARE
My Commission Expires April 30, 2009

EXHIBIT A

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

BPU Docket Nos. EO08050326 and EO07110881

TESTIMONY OF
JOSEPH F. JANOCHA

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

BPU Docket Nos. EO08050326 and EO07110881

August 1, 2008

TESTIMONY OF

Joseph F. Janocha

ON BEHALF OF
ATLANTIC CITY ELECTRIC COMPANY

Q. Please state your name, position and address.

A. My name is Joseph F. Janocha. I am a Regulatory Affairs Manager in the Rates and Technical Services Section of Pepco Holdings Inc. ("PHI"). I am testifying on behalf of Atlantic City Electric Company (referred to herein as "ACE" or the "Company").

Q. What is your educational and professional background?

A. I have a Bachelor of Engineering degree with a concentration in Mechanical Engineering from Stevens Institute of Technology. I am a Registered Professional Engineer in the State of New Jersey and the Commonwealth of Pennsylvania.

Q. Please describe and summarize your employment experience in the utility industry.

A. I began my career with Philadelphia Electric Company (now known as Exelon) ("PECO") in 1982 as an engineer in the Mechanical Engineering Division. From 1982 through 1992, I held various positions in PECO's Mechanical Engineering, Nuclear Quality Assurance, and Nuclear Engineering Divisions. I joined ACE in 1992 as a Senior Engineer in the Joint Generation Department. In 1998, I joined the Regulatory Affairs group as a Coordinator, responsible for the design and administration of electric rates for the Company. I assumed my current position in March 2005. In this capacity, I am responsible for the development and administration of unbundled rates for PHI's ACE and Delmarva Power & Light Company subsidiaries.

Q. Have you filed testimony in any other proceedings?

A. Yes. I have previously presented and/or filed testimony as a witness before the New Jersey Board of Public Utilities (referred to herein as the "Board" or "BPU"), the Delaware Public Service Commission, the Maryland Public Service Commission, and the State Corporation Commission of Virginia.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's proposed mechanism to recover the costs associated with the proposed Direct Load Control ("DLC") program. The Company is proposing that costs associated with the program be recovered through the System Control Charge ("SCC"). This charge was established in 2004 for the express purpose of recovering the costs associated with utility-sponsored demand response programs. The proposed tariff modification required to incorporate cost recovery of the proposed DLC program is provided as Schedule JFJ-5.

Q. Please describe the costs proposed to be recovered through the SCC.

A. The SCC would recover the following costs associated with the Company's proposed DLC program:

- Capital Costs associated with for the installation of remotely controlled smart thermostats, load research meters, load research feeders and the demand response internet platform. The Company proposes to amortize these costs over a period of 15 years. Pursuant to N.J.S.A. 48:3-98.1(b), the Company is seeking a return on equity in the determination of the carrying costs associated with the amortization of these expenditures. Therefore, a return on the unamortized balance would be calculated using the Company's authorized rate of return, as approved by the BPU in its May 26, 2005 Order in Docket No. ER03020110. Schedule JFJ-3 provides the capital structure inherent in the authorized rate of return, as well as the most recent capital structure.

- Participant Incentive payments of $50 per participant
- Marketing costs incurred for direct recruitment materials, mailing expense, and the handling of customer inquiries
- Maintenance expenses, as well as load research monitoring expense representing the additional expense to retrieve and store program-related load research data

Q. How is the SCC rate mechanism designed?

A. The SCC will continue to be designed on a dollar per kilowatt-hour ("kWh") basis, applicable equally to all Rate Schedules. The revenue requirements would be calculated as follows:

Revenue Requirements = Unamortized Equipment Installation Costs x Allowed Rate of Return + Amortization Expense + Participant Incentives + Marketing Costs + Maintenance and Monitoring Costs.

The Company is further requesting that the SCC continue to be subject to deferred accounting. Any differences between the monthly revenue requirement and the monthly SCC sales revenue will be tracked as a deferred balance. Interest on this balance will be calculated monthly based on the Company's current short-term debt rate. This interest calculation method has been approved by the Board for the Company's Societal Benefits Charge deferrals as well as it Non Utility Generation Charge (NGC) deferral in BPU Docket No. ER02080510 and, most recently, in BPU Docket No. ER07060356.

Details of the proposed rate design and amortization mechanism are provided in Schedules JFJ-1 and JFJ-2.

Q. Have you done a bill impact analysis for the proposed SCC rate change?

A. Yes. As noted on Schedule JFJ-1, the highest projected SCC rate for the five year period of 2009 through 2013 is $0.000239 per kWh and occurs in 2013. For a typical residential customer using 1,000 kWhs per month, this amounts to a monthly bill impact of $0.17. This amounts to a monthly increase of 0.12% based on current rates. The residential bill impact calculation is provided in Schedule JFJ-4.

Q. Does this conclude your testimony?

A. Yes.

Atlantic City Electric Company
FORECASTED SYSTEM CONTROL CHARGE (SCC) DEVELOPMENT

Recovery (Thousands of Dollars)	2009	2010	2011	2012	2013
Installation Cost Amortization (Straight Line)	$ 155	$ 371	$ 588	$ 799	$ 922
Annual Expenses	$ 216	$ 210	$ 253	$ 236	$ 236
Participant Incentives	$ 130	$ 495	$ 495	$ 495	$ 495
CCRF (Based on 8.14% ROR, adj. for income tax)	$ 61	$ 239	$ 426	$ 593	$ 728
Total Recovery before Offsets	$ 562	$ 1,314	$ 1,762	$ 2,122	$ 2,381
BPU Assessment	$ 3	$ 7	$ 9	$ 11	$ 12
Total Overall Revenue Requirement	$ 565	$ 1,321	$ 1,771	$ 2,133	$ 2,393
Annual Sales (MWH)	10,260,209	10,391,042	10,546,826	10,726,682	10,726,682
SCC ($/kWh)	$ 0.000055	$ 0.000127	$ 0.000168	$ 0.000199	$ 0.000223
SCC - w/ SUT ($/kWh)	$ 0.000059	$ 0.000136	$ 0.000180	$ 0.000213	$ 0.000239

Pro-Forma Income Statement (Thousands of Dollars)	2009	2010	2011	2012	2013
Revenue	$ 565	$ 1,321	$ 1,771	$ 2,133	$ 2,393
Annual Expense	$ 216	$ 210	$ 253	$ 236	$ 236
Incentives	$ 130	$ 495	$ 495	$ 495	$ 495
Amortization Expense	$ 155	$ 371	$ 588	$ 799	$ 922
BPU Assessment	$ 3	$ 7	$ 9	$ 11	$ 12
Total Expenses	$ 504	$ 1,083	$ 1,345	$ 1,541	$ 1,665
Earnings Before Interest and Taxes	$ 61	$ 239	$ 426	$ 593	$ 728
Interest Expense	$ 19	$ 76	$ 136	$ 189	$ 232
Income Tax	$ 17	$ 66	$ 119	$ 165	$ 203
Net Income	$ 24	$ 96	$ 172	$ 239	$ 293
Return on Equity per WACC	$ 24	$ 96	$ 171	$ 238	$ 292

Atlantic City Electric Company
SCC Workpaper
Computation of Forecasted Annual Amortization and CCRF Cost Components
Installation Costs 15 Year Recovery

Month	Unamortized Beginning Balance	Additional Program Costs	Market Earnings Offset	Amortization 1	Amortization 2	Amortization 3	Amortization 4	Unamortized Ending Balance	Deferred Tax Activity	Accum Deferred Tax	Unamortized Ending Bal, net of Accum Deferred Tax	CCRF Rate Net-of-Tax	Estimated CCRF Net-of-Tax	CCRF Adjusted for Income Tax
Jun-09	0	$ 143,571		(13,008)				130,563	$ (53,641)	$ (53,641)	$ 76,922	6.66%	$ 213	362
Jul-09	130,563	$ 143,571		(12,426)				261,708	$ (53,880)	$ (107,521)	$ 154,187	6.66%	$ 641	1,089
Aug-09	261,708	$ 143,571		(12,065)				393,214	$ (54,028)	$ (161,549)	$ 231,665	6.66%	$ 1,071	1,818
Sep-09	393,214	$ 143,571		(11,469)				525,316	$ (54,273)	$ (215,822)	$ 309,494	6.66%	$ 1,502	2,549
Oct-09	525,316	$ 143,571		(10,888)				658,000	$ (54,512)	$ (270,334)	$ 387,666	6.66%	$ 1,935	3,284
Nov-09	658,000	$ 143,571		(12,342)				789,229	$ (53,914)	$ (324,248)	$ 464,981	6.66%	$ 2,366	4,017
Dec-09	789,229	$ 143,571		(15,474)				917,327	$ (52,628)	$ (376,876)	$ 540,451	6.66%	$ 2,790	4,736
Jan-10	917,327	$ 263,750		(16,761)				1,164,316	$ (101,473)	$ (478,349)	$ 685,967	6.66%	$ 3,404	5,777
Feb-10	1,164,316	$ 263,750		(15,298)				1,412,767	$ (102,074)	$ (580,423)	$ 832,344	6.66%	$ 4,214	7,152
Mar-10	1,412,767	$ 263,750		(12,146)				1,664,372	$ (103,369)	$ (683,792)	$ 980,580	6.66%	$ 5,032	8,540
Apr-10	1,664,372	$ 263,750		(11,144)				1,916,977	$ (103,781)	$ (787,573)	$ 1,129,404	6.66%	$ 5,856	9,940
May-10	1,916,977	$ 263,750		(11,894)				2,168,833	$ (103,472)	$ (891,045)	$ 1,277,788	6.66%	$ 6,681	11,340
Jun-10	2,168,833	$ 263,750	$ -	(13,008)	(18,114)			2,401,461	$ (95,573)	$ (986,618)	$ 1,414,843	6.66%	$ 7,473	12,684
Jul-10	2,401,461	$ 263,750		(12,426)	(17,304)			2,635,481	$ (96,145)	$ (1,082,763)	$ 1,552,718	6.66%	$ 8,236	13,979
Aug-10	2,635,481	$ 263,750		(12,065)	(16,801)			2,870,365	$ (96,500)	$ (1,179,263)	$ 1,691,102	6.66%	$ 9,003	15,281
Sep-10	2,870,365	$ 263,750		(11,469)	(15,971)			3,106,674	$ (97,085)	$ (1,276,348)	$ 1,830,326	6.66%	$ 9,773	16,589
Oct-10	3,106,674	$ 263,750		(10,888)	(15,162)			3,344,374	$ (97,657)	$ (1,374,005)	$ 1,970,369	6.66%	$ 10,548	17,904
Nov-10	3,344,374	$ 263,750		(12,342)	(17,186)			3,578,596	$ (96,228)	$ (1,470,233)	$ 2,108,363	6.66%	$ 11,320	19,214
Dec-10	3,578,596	$ 263,750		(15,474)	(21,547)			3,805,326	$ (93,150)	$ (1,563,383)	$ 2,241,943	6.66%	$ 12,074	20,493
Jan-11	3,805,326	$ 277,917		(16,761)	(23,340)			4,043,141	$ (97,704)	$ (1,661,087)	$ 2,382,054	6.66%	$ 12,833	21,782
Feb-11	4,043,141	$ 277,917		(15,298)	(21,303)			4,284,456	$ (99,142)	$ (1,760,229)	$ 2,524,227	6.66%	$ 13,617	23,112
Mar-11	4,284,456	$ 277,917		(12,146)	(16,913)			4,533,314	$ (102,241)	$ (1,862,470)	$ 2,670,844	6.66%	$ 14,418	24,473
Apr-11	4,533,314	$ 277,917		(11,144)	(15,518)			4,784,568	$ (103,225)	$ (1,965,695)	$ 2,818,873	6.66%	$ 15,236	25,861
May-11	4,784,568	$ 277,917		(11,894)	(16,563)			5,034,028	$ (102,488)	$ (2,068,183)	$ 2,965,845	6.66%	$ 16,055	27,250
Jun-11	5,034,028	$ 277,917	$ -	(13,008)	(18,114)	(18,273)		5,262,550	$ (93,886)	$ (2,162,069)	$ 3,100,481	6.66%	$ 16,836	28,577
Jul-11	5,262,550	$ 277,917		(12,426)	(17,304)	(17,455)		5,493,281	$ (94,794)	$ (2,256,863)	$ 3,236,418	6.66%	$ 17,587	29,851
Aug-11	5,493,281	$ 277,917		(12,065)	(16,801)	(16,948)		5,725,383	$ (95,357)	$ (2,352,220)	$ 3,373,163	6.66%	$ 18,344	31,136
Sep-11	5,725,383	$ 277,917		(11,469)	(15,971)	(16,111)		5,959,748	$ (96,286)	$ (2,448,506)	$ 3,511,242	6.66%	$ 19,107	32,431
Oct-11	5,959,748	$ 277,917		(10,888)	(15,162)	(15,295)		6,196,320	$ (97,193)	$ (2,545,699)	$ 3,650,621	6.66%	$ 19,877	33,738
Nov-11	6,196,320	$ 277,917		(12,342)	(17,186)	(17,336)		6,427,373	$ (94,926)	$ (2,640,625)	$ 3,786,748	6.66%	$ 20,641	35,035
Dec-11	6,427,373	$ 277,917		(15,474)	(21,547)	(21,736)		6,646,533	$ (90,040)	$ (2,730,665)	$ 3,915,868	6.66%	$ 21,378	36,285
Jan-12	6,646,533	$ 263,750		(16,761)	(23,340)	(23,545)		6,846,637	$ (82,211)	$ (2,812,876)	$ 4,033,761	6.66%	$ 22,063	37,449
Feb-12	6,846,637	$ 263,750		(15,298)	(21,303)	(21,490)		7,052,296	$ (84,493)	$ (2,897,369)	$ 4,154,927	6.66%	$ 22,727	38,575
Mar-12	7,052,296	$ 263,750		(12,146)	(16,913)	(17,061)		7,269,926	$ (89,411)	$ (2,986,780)	$ 4,283,146	6.66%	$ 23,419	39,749
Apr-12	7,269,926	$ 263,750		(11,144)	(15,518)	(15,654)		7,491,359	$ (90,973)	$ (3,077,753)	$ 4,413,606	6.66%	$ 24,137	40,968
May-12	7,491,359	$ 263,750		(11,894)	(16,563)	(16,708)		7,709,944	$ (89,804)	$ (3,167,557)	$ 4,542,387	6.66%	$ 24,856	42,189
Jun-12	7,709,944	$ 263,750	$ -	(13,008)	(18,114)	(18,273)	(17,717)	7,906,583	$ (80,787)	$ (3,248,344)	$ 4,658,239	6.66%	$ 25,535	43,342
Jul-12	7,906,583	$ 263,750		(12,426)	(17,304)	(17,455)	(16,925)	8,106,222	$ (82,020)	$ (3,330,364)	$ 4,775,858	6.66%	$ 26,183	44,442
Aug-12	8,106,222	$ 263,750		(12,065)	(16,801)	(16,948)	(16,433)	8,307,724	$ (82,785)	$ (3,413,149)	$ 4,894,575	6.66%	$ 26,839	45,555
Sep-12	8,307,724	$ 263,750		(11,469)	(15,971)	(16,111)	(15,622)	8,512,301	$ (84,048)	$ (3,497,197)	$ 5,015,104	6.66%	$ 27,503	46,682
Oct-12	8,512,301	$ 263,750		(10,888)	(15,162)	(15,295)	(14,830)	8,719,876	$ (85,280)	$ (3,582,477)	$ 5,137,399	6.66%	$ 28,177	47,826
Nov-12	8,719,876	$ 263,750		(12,342)	(17,186)	(17,336)	(16,810)	8,919,952	$ (82,199)	$ (3,664,676)	$ 5,255,276	6.66%	$ 28,844	48,957
Dec-12	8,919,952	$ 263,750		(15,474)	(21,547)	(21,736)	(21,075)	9,103,871	$ (75,561)	$ (3,740,237)	$ 5,363,634	6.66%	$ 29,471	50,023
Jan-13	9,103,871	$ 263,750		(16,761)	(23,340)	(23,545)	(22,829)	9,281,145	$ (72,832)	$ (3,813,069)	$ 5,468,076	6.66%	$ 30,062	51,025
Feb-13	9,281,145	$ 263,750		(15,298)	(21,303)	(21,490)	(20,837)	9,465,967	$ (75,932)	$ (3,889,001)	$ 5,576,966	6.66%	$ 30,654	52,030
Mar-13	9,465,967	$ 263,750		(12,146)	(16,913)	(17,061)	(16,543)	9,667,055	$ (82,615)	$ (3,971,616)	$ 5,695,439	6.66%	$ 31,285	53,101
Apr-13	9,667,055	$ 263,750		(11,144)	(15,518)	(15,654)	(15,179)	9,873,309	$ (84,737)	$ (4,056,353)	$ 5,816,956	6.66%	$ 31,951	54,232
May-13	9,873,309	$ 263,750		(11,894)	(16,563)	(16,708)	(16,200)	10,075,694	$ (83,148)	$ (4,139,501)	$ 5,936,193	6.66%	$ 32,619	55,366
Jun-13	10,075,694	$ 263,750	$ -	(13,008)	(18,114)	(18,273)	(17,717)	10,261,997	$ (76,541)	$ (4,216,042)	$ 6,045,955	6.66%	$ 33,255	56,445
Jul-13	10,261,997	$ 263,750		(12,426)	(17,304)	(17,455)	(16,925)	10,451,764	$ (77,964)	$ (4,294,006)	$ 6,157,758	6.66%	$ 33,870	57,488
Aug-13	10,451,764	$ 263,750		(12,065)	(16,801)	(16,948)	(16,433)	10,643,680	$ (78,847)	$ (4,372,853)	$ 6,270,827	6.66%	$ 34,494	58,548
Sep-13	10,643,680	$ 263,750		(11,469)	(15,971)	(16,111)	(15,622)	10,839,144	$ (80,304)	$ (4,453,157)	$ 6,385,987	6.66%	$ 35,127	59,623
Oct-13	10,839,144	$ 263,750		(10,888)	(15,162)	(15,295)	(14,830)	11,038,069	$ (81,726)	$ (4,534,883)	$ 6,503,186	6.66%	$ 35,772	60,717
Nov-13	11,038,069	$ 263,750		(12,342)	(17,186)	(17,336)	(16,810)	11,228,339	$ (78,171)	$ (4,613,054)	$ 6,615,285	6.66%	$ 36,409	61,798
Dec-13	11,228,339	$ 263,750		(15,474)	(21,547)	(21,736)	(21,075)	11,399,963	$ (70,510)	$ (4,683,564)	$ 6,716,399	6.66%	$ 37,000	62,802
Jan-14	11,399,963	$ -		(16,761)	(23,340)	(23,545)	(22,829)	11,300,171	$ 40,999	$ (4,642,565)	$ 6,657,606	6.66%	$ 37,118	63,001
Feb-14	11,300,171	$ -		(15,298)	(21,303)	(21,490)	(20,837)	11,209,088	$ 37,421	$ (4,605,144)	$ 6,603,944	6.66%	$ 36,806	62,472
Mar-14	11,209,088	$ -		(12,146)	(16,913)	(17,061)	(16,543)	11,136,776	$ 29,709	$ (4,575,435)	$ 6,561,341	6.66%	$ 36,539	62,018
Apr-14	11,136,776	$ -		(11,144)	(15,518)	(15,654)	(15,179)	11,070,426	$ 27,259	$ (4,548,176)	$ 6,522,250	6.66%	$ 36,312	61,633
May-14	11,070,426	$ -		(11,894)	(16,563)	(16,708)	(16,200)	10,999,611	$ 29,093	$ (4,519,083)	$ 6,480,528	6.66%	$ 36,088	61,253
Jun-14	10,999,611	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	10,922,164	$ 31,818	$ (4,487,265)	$ 6,434,899	6.66%	$ 35,845	60,841
Jul-14	10,922,164	$ -		(12,426)	(17,304)	(17,455)	(16,925)	10,848,181	$ 30,395	$ (4,456,870)	$ 6,391,311	6.66%	$ 35,598	60,421

Atlantic City Electric Company
SCC Workpaper
Computation of Forecasted Annual Amortization and CCRF Cost Components
Installation Costs 15 Year Recovery

Month	Unamortized Beginning Balance	Additional Program Costs	Market Earnings Offset	Amortization 1	Amortization 2	Amortization 3	Amortization 4	Unamortized Ending Balance	Deferred Tax Activity	Accum Deferred Tax	Unamortized Ending Bal, net of Accum Deferred Tax	CCRF Rate Net-of-Tax	Estimated CCRF Net-of-Tax	CCRF Adjusted for Income Tax
Aug-14	10,848,181	$ -		(12,065)	(16,801)	(16,948)	(16,433)	10,776,347	$ 29,512	$ (4,427,358)	$ 6,348,989	6.66%	$ 35,359	60,016
Sep-14	10,776,347	$ -		(11,469)	(15,971)	(16,111)	(15,622)	10,708,061	$ 28,055	$ (4,399,303)	$ 6,308,758	6.66%	$ 35,130	59,627
Oct-14	10,708,061	$ -		(10,888)	(15,162)	(15,295)	(14,830)	10,643,235	$ 26,633	$ (4,372,670)	$ 6,270,565	6.66%	$ 34,912	59,258
Nov-14	10,643,235	$ -		(12,342)	(17,186)	(17,336)	(16,810)	10,569,756	$ 30,188	$ (4,342,482)	$ 6,227,274	6.66%	$ 34,686	58,874
Dec-14	10,569,756	$ -		(15,474)	(21,547)	(21,736)	(21,075)	10,477,630	$ 37,849	$ (4,304,633)	$ 6,172,997	6.66%	$ 34,415	58,414
Jan-15	10,477,630	$ -		(16,761)	(23,340)	(23,545)	(22,829)	10,377,838	$ 40,999	$ (4,263,634)	$ 6,114,204	6.66%	$ 34,102	57,882
Feb-15	10,377,838	$ -		(15,298)	(21,303)	(21,490)	(20,837)	10,286,755	$ 37,421	$ (4,226,213)	$ 6,060,542	6.66%	$ 33,789	57,352
Mar-15	10,286,755	$ -		(12,146)	(16,913)	(17,061)	(16,543)	10,214,442	$ 29,709	$ (4,196,504)	$ 6,017,938	6.66%	$ 33,522	56,898
Apr-15	10,214,442	$ -		(11,144)	(15,518)	(15,654)	(15,179)	10,148,092	$ 27,259	$ (4,169,245)	$ 5,978,847	6.66%	$ 33,296	56,514
May-15	10,148,092	$ -		(11,894)	(16,563)	(16,708)	(16,200)	10,077,278	$ 29,093	$ (4,140,152)	$ 5,937,126	6.66%	$ 33,071	56,133
Jun-15	10,077,278	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	9,999,831	$ 31,818	$ (4,108,334)	$ 5,891,497	6.66%	$ 32,829	55,721
Jul-15	9,999,831	$ -		(12,426)	(17,304)	(17,455)	(16,925)	9,925,847	$ 30,395	$ (4,077,939)	$ 5,847,908	6.66%	$ 32,581	55,301
Aug-15	9,925,847	$ -		(12,065)	(16,801)	(16,948)	(16,433)	9,854,014	$ 29,512	$ (4,048,427)	$ 5,805,587	6.66%	$ 32,343	54,896
Sep-15	9,854,014	$ -		(11,469)	(15,971)	(16,111)	(15,622)	9,785,727	$ 28,055	$ (4,020,372)	$ 5,765,355	6.66%	$ 32,114	54,508
Oct-15	9,785,727	$ -		(10,888)	(15,162)	(15,295)	(14,830)	9,720,902	$ 26,633	$ (3,993,739)	$ 5,727,163	6.66%	$ 31,896	54,138
Nov-15	9,720,902	$ -		(12,342)	(17,186)	(17,336)	(16,810)	9,647,422	$ 30,188	$ (3,963,551)	$ 5,683,871	6.66%	$ 31,670	53,754
Dec-15	9,647,422	$ -		(15,474)	(21,547)	(21,736)	(21,075)	9,555,297	$ 37,849	$ (3,925,702)	$ 5,629,595	6.66%	$ 31,399	53,295
Jan-16	9,555,297	$ -		(16,761)	(23,340)	(23,545)	(22,829)	9,455,504	$ 40,999	$ (3,884,703)	$ 5,570,801	6.66%	$ 31,085	52,762
Feb-16	9,455,504	$ -		(15,298)	(21,303)	(21,490)	(20,837)	9,364,421	$ 37,421	$ (3,847,282)	$ 5,517,139	6.66%	$ 30,773	52,232
Mar-16	9,364,421	$ -		(12,146)	(16,913)	(17,061)	(16,543)	9,292,109	$ 29,709	$ (3,817,573)	$ 5,474,536	6.66%	$ 30,506	51,779
Apr-16	9,292,109	$ -		(11,144)	(15,518)	(15,654)	(15,179)	9,225,759	$ 27,259	$ (3,790,314)	$ 5,435,445	6.66%	$ 30,279	51,394
May-16	9,225,759	$ -		(11,894)	(16,563)	(16,708)	(16,200)	9,154,944	$ 29,093	$ (3,761,221)	$ 5,393,723	6.66%	$ 30,055	51,013
Jun-16	9,154,944	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	9,077,497	$ 31,818	$ (3,729,403)	$ 5,348,094	6.66%	$ 29,813	50,602
Jul-16	9,077,497	$ -		(12,426)	(17,304)	(17,455)	(16,925)	9,003,514	$ 30,395	$ (3,699,008)	$ 5,304,506	6.66%	$ 29,565	50,182
Aug-16	9,003,514	$ -		(12,065)	(16,801)	(16,948)	(16,433)	8,931,680	$ 29,512	$ (3,669,496)	$ 5,262,184	6.66%	$ 29,327	49,777
Sep-16	8,931,680	$ -		(11,469)	(15,971)	(16,111)	(15,622)	8,863,394	$ 28,055	$ (3,641,441)	$ 5,221,953	6.66%	$ 29,097	49,388
Oct-16	8,863,394	$ -		(10,888)	(15,162)	(15,295)	(14,830)	8,798,569	$ 26,633	$ (3,614,808)	$ 5,183,761	6.66%	$ 28,880	49,019
Nov-16	8,798,569	$ -		(12,342)	(17,186)	(17,336)	(16,810)	8,725,089	$ 30,188	$ (3,584,620)	$ 5,140,469	6.66%	$ 28,654	48,635
Dec-16	8,725,089	$ -		(15,474)	(21,547)	(21,736)	(21,075)	8,632,963	$ 37,849	$ (3,546,771)	$ 5,086,192	6.66%	$ 28,383	48,175
Jan-17	8,632,963	$ -		(16,761)	(23,340)	(23,545)	(22,829)	8,533,171	$ 40,999	$ (3,505,772)	$ 5,027,399	6.66%	$ 28,069	47,642
Feb-17	8,533,171	$ -		(15,298)	(21,303)	(21,490)	(20,837)	8,442,088	$ 37,421	$ (3,468,351)	$ 4,973,737	6.66%	$ 27,757	47,113
Mar-17	8,442,088	$ -		(12,146)	(16,913)	(17,061)	(16,543)	8,369,776	$ 29,709	$ (3,438,642)	$ 4,931,134	6.66%	$ 27,490	46,659
Apr-17	8,369,776	$ -		(11,144)	(15,518)	(15,654)	(15,179)	8,303,426	$ 27,259	$ (3,411,383)	$ 4,892,043	6.66%	$ 27,263	46,274
May-17	8,303,426	$ -		(11,894)	(16,563)	(16,708)	(16,200)	8,232,611	$ 29,093	$ (3,382,290)	$ 4,850,321	6.66%	$ 27,039	45,894
Jun-17	8,232,611	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	8,155,164	$ 31,818	$ (3,350,472)	$ 4,804,692	6.66%	$ 26,796	45,482
Jul-17	8,155,164	$ -		(12,426)	(17,304)	(17,455)	(16,925)	8,081,181	$ 30,395	$ (3,320,077)	$ 4,761,104	6.66%	$ 26,549	45,062
Aug-17	8,081,181	$ -		(12,065)	(16,801)	(16,948)	(16,433)	8,009,347	$ 29,512	$ (3,290,565)	$ 4,718,782	6.66%	$ 26,310	44,657
Sep-17	8,009,347	$ -		(11,469)	(15,971)	(16,111)	(15,622)	7,941,061	$ 28,055	$ (3,262,510)	$ 4,678,551	6.66%	$ 26,081	44,268
Oct-17	7,941,061	$ -		(10,888)	(15,162)	(15,295)	(14,830)	7,876,235	$ 26,633	$ (3,235,877)	$ 4,640,358	6.66%	$ 25,863	43,899
Nov-17	7,876,235	$ -		(12,342)	(17,186)	(17,336)	(16,810)	7,802,756	$ 30,188	$ (3,205,689)	$ 4,597,067	6.66%	$ 25,637	43,515
Dec-17	7,802,756	$ -		(15,474)	(21,547)	(21,736)	(21,075)	7,710,630	$ 37,849	$ (3,167,840)	$ 4,542,790	6.66%	$ 25,367	43,055
Jan-18	7,710,630	$ -		(16,761)	(23,340)	(23,545)	(22,829)	7,610,838	$ 40,999	$ (3,126,841)	$ 4,483,997	6.66%	$ 25,053	42,523
Feb-18	7,610,838	$ -		(15,298)	(21,303)	(21,490)	(20,837)	7,519,755	$ 37,421	$ (3,089,420)	$ 4,430,335	6.66%	$ 24,741	41,993
Mar-18	7,519,755	$ -		(12,146)	(16,913)	(17,061)	(16,543)	7,447,442	$ 29,709	$ (3,059,711)	$ 4,387,731	6.66%	$ 24,473	41,540
Apr-18	7,447,442	$ -		(11,144)	(15,518)	(15,654)	(15,179)	7,381,092	$ 27,259	$ (3,032,452)	$ 4,348,640	6.66%	$ 24,247	41,155
May-18	7,381,092	$ -		(11,894)	(16,563)	(16,708)	(16,200)	7,310,278	$ 29,093	$ (3,003,359)	$ 4,306,919	6.66%	$ 24,022	40,774
Jun-18	7,310,278	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	7,232,831	$ 31,818	$ (2,971,541)	$ 4,261,290	6.66%	$ 23,780	40,363
Jul-18	7,232,831	$ -		(12,426)	(17,304)	(17,455)	(16,925)	7,158,847	$ 30,395	$ (2,941,146)	$ 4,217,701	6.66%	$ 23,532	39,942
Aug-18	7,158,847	$ -		(12,065)	(16,801)	(16,948)	(16,433)	7,087,014	$ 29,512	$ (2,911,634)	$ 4,175,380	6.66%	$ 23,294	39,538
Sep-18	7,087,014	$ -		(11,469)	(15,971)	(16,111)	(15,622)	7,018,727	$ 28,055	$ (2,883,579)	$ 4,135,148	6.66%	$ 23,065	39,149
Oct-18	7,018,727	$ -		(10,888)	(15,162)	(15,295)	(14,830)	6,953,902	$ 26,633	$ (2,856,946)	$ 4,096,956	6.66%	$ 22,847	38,779
Nov-18	6,953,902	$ -		(12,342)	(17,186)	(17,336)	(16,810)	6,880,422	$ 30,188	$ (2,826,758)	$ 4,053,664	6.66%	$ 22,621	38,395
Dec-18	6,880,422	$ -		(15,474)	(21,547)	(21,736)	(21,075)	6,788,297	$ 37,849	$ (2,788,909)	$ 3,999,388	6.66%	$ 22,350	37,936
Jan-19	6,788,297	$ -		(16,761)	(23,340)	(23,545)	(22,829)	6,688,504	$ 40,999	$ (2,747,910)	$ 3,940,594	6.66%	$ 22,036	37,403
Feb-19	6,688,504	$ -		(15,298)	(21,303)	(21,490)	(20,837)	6,597,421	$ 37,421	$ (2,710,489)	$ 3,886,932	6.66%	$ 21,724	36,873
Mar-19	6,597,421	$ -		(12,146)	(16,913)	(17,061)	(16,543)	6,525,109	$ 29,709	$ (2,680,780)	$ 3,844,329	6.66%	$ 21,457	36,420
Apr-19	6,525,109	$ -		(11,144)	(15,518)	(15,654)	(15,179)	6,458,759	$ 27,259	$ (2,653,521)	$ 3,805,238	6.66%	$ 21,230	36,035
May-19	6,458,759	$ -		(11,894)	(16,563)	(16,708)	(16,200)	6,387,944	$ 29,093	$ (2,624,428)	$ 3,763,516	6.66%	$ 21,006	35,654
Jun-19	6,387,944	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	6,310,497	$ 31,818	$ (2,592,610)	$ 3,717,887	6.66%	$ 20,764	35,243
Jul-19	6,310,497	$ -		(12,426)	(17,304)	(17,455)	(16,925)	6,236,514	$ 30,395	$ (2,562,215)	$ 3,674,299	6.66%	$ 20,516	34,823
Aug-19	6,236,514	$ -		(12,065)	(16,801)	(16,948)	(16,433)	6,164,680	$ 29,512	$ (2,532,703)	$ 3,631,977	6.66%	$ 20,278	34,418
Sep-19	6,164,680	$ -		(11,469)	(15,971)	(16,111)	(15,622)	6,096,394	$ 28,055	$ (2,504,648)	$ 3,591,746	6.66%	$ 20,049	34,029

Atlantic City Electric Company
SCC Workpaper
Computation of Forecasted Annual Amortization and CCRF Cost Components
Installation Costs 15 Year Recovery

Month	Unamortized Beginning Balance	Additional Program Costs	Market Earnings Offset	Amortization 1	Amortization 2	Amortization 3	Amortization 4	Unamortized Ending Balance	Deferred Tax Activity	Accum Deferred Tax	Unamortized Ending Bal. net of Accum Deferred Tax	CCRF Rate Net-of-Tax	Estimated CCRF Net-of-Tax	CCRF Adjusted for Income Tax
Oct-19	6,096,394	$ -		(10,888)	(15,162)	(15,295)	(14,830)	6,031,569	$ 26,633	$ (2,478,015)	$ 3,553,554	6.66%	$ 19,831	33,660
Nov-19	6,031,569	$ -		(12,342)	(17,186)	(17,336)	(16,810)	5,958,089	$ 30,188	$ (2,447,827)	$ 3,510,262	6.66%	$ 19,605	33,276
Dec-19	5,958,089	$ -		(15,474)	(21,547)	(21,736)	(21,075)	5,865,963	$ 37,849	$ (2,409,978)	$ 3,455,985	6.66%	$ 19,334	32,816
Jan-20	5,865,963	$ -		(16,761)	(23,340)	(23,545)	(22,829)	5,766,171	$ 40,999	$ (2,368,979)	$ 3,397,192	6.66%	$ 19,020	32,283
Feb-20	5,766,171	$ -		(15,298)	(21,303)	(21,490)	(20,837)	5,675,088	$ 37,421	$ (2,331,558)	$ 3,343,530	6.66%	$ 18,708	31,754
Mar-20	5,675,088	$ -		(12,146)	(16,913)	(17,061)	(16,543)	5,602,776	$ 29,709	$ (2,301,849)	$ 3,300,927	6.66%	$ 18,441	31,300
Apr-20	5,602,776	$ -		(11,144)	(15,518)	(15,654)	(15,179)	5,536,426	$ 27,259	$ (2,274,590)	$ 3,261,836	6.66%	$ 18,214	30,915
May-20	5,536,426	$ -		(11,894)	(16,563)	(16,708)	(16,200)	5,465,611	$ 29,093	$ (2,245,497)	$ 3,220,114	6.66%	$ 17,990	30,535
Jun-20	5,465,611	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	5,388,164	$ 31,818	$ (2,213,679)	$ 3,174,485	6.66%	$ 17,747	30,123
Jul-20	5,388,164	$ -		(12,426)	(17,304)	(17,455)	(16,925)	5,314,181	$ 30,395	$ (2,183,284)	$ 3,130,897	6.66%	$ 17,500	29,703
Aug-20	5,314,181	$ -		(12,065)	(16,801)	(16,948)	(16,433)	5,242,347	$ 29,512	$ (2,153,772)	$ 3,088,575	6.66%	$ 17,261	29,298
Sep-20	5,242,347	$ -		(11,469)	(15,971)	(16,111)	(15,622)	5,174,061	$ 28,055	$ (2,125,717)	$ 3,048,344	6.66%	$ 17,032	28,909
Oct-20	5,174,061	$ -		(10,888)	(15,162)	(15,295)	(14,830)	5,109,235	$ 26,633	$ (2,099,084)	$ 3,010,151	6.66%	$ 16,815	28,540
Nov-20	5,109,235	$ -		(12,342)	(17,186)	(17,336)	(16,810)	5,035,756	$ 30,188	$ (2,068,896)	$ 2,966,860	6.66%	$ 16,588	28,156
Dec-20	5,035,756	$ -		(15,474)	(21,547)	(21,736)	(21,075)	4,943,630	$ 37,849	$ (2,031,047)	$ 2,912,583	6.66%	$ 16,318	27,696
Jan-21	4,943,630	$ -		(16,761)	(23,340)	(23,545)	(22,829)	4,843,838	$ 40,999	$ (1,990,048)	$ 2,853,790	6.66%	$ 16,004	27,164
Feb-21	4,843,838	$ -		(15,298)	(21,303)	(21,490)	(20,837)	4,752,755	$ 37,421	$ (1,952,627)	$ 2,800,128	6.66%	$ 15,692	26,634
Mar-21	4,752,755	$ -		(12,146)	(16,913)	(17,061)	(16,543)	4,680,442	$ 29,709	$ (1,922,918)	$ 2,757,524	6.66%	$ 15,425	26,181
Apr-21	4,680,442	$ -		(11,144)	(15,518)	(15,654)	(15,179)	4,614,092	$ 27,259	$ (1,895,659)	$ 2,718,433	6.66%	$ 15,198	25,796
May-21	4,614,092	$ -		(11,894)	(16,563)	(16,708)	(16,200)	4,543,278	$ 29,093	$ (1,866,566)	$ 2,676,712	6.66%	$ 14,974	25,415
Jun-21	4,543,278	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	4,465,831	$ 31,818	$ (1,834,748)	$ 2,631,083	6.66%	$ 14,731	25,004
Jul-21	4,465,831	$ -		(12,426)	(17,304)	(17,455)	(16,925)	4,391,847	$ 30,395	$ (1,804,353)	$ 2,587,494	6.66%	$ 14,484	24,583
Aug-21	4,391,847	$ -		(12,065)	(16,801)	(16,948)	(16,433)	4,320,014	$ 29,512	$ (1,774,841)	$ 2,545,173	6.66%	$ 14,245	24,179
Sep-21	4,320,014	$ -		(11,469)	(15,971)	(16,111)	(15,622)	4,251,727	$ 28,055	$ (1,746,786)	$ 2,504,941	6.66%	$ 14,016	23,790
Oct-21	4,251,727	$ -		(10,888)	(15,162)	(15,295)	(14,830)	4,186,902	$ 26,633	$ (1,720,153)	$ 2,466,749	6.66%	$ 13,798	23,420
Nov-21	4,186,902	$ -		(12,342)	(17,186)	(17,336)	(16,810)	4,113,422	$ 30,188	$ (1,689,965)	$ 2,423,457	6.66%	$ 13,572	23,036
Dec-21	4,113,422	$ -		(15,474)	(21,547)	(21,736)	(21,075)	4,021,297	$ 37,849	$ (1,652,116)	$ 2,369,181	6.66%	$ 13,301	22,577
Jan-22	4,021,297	$ -		(16,761)	(23,340)	(23,545)	(22,829)	3,921,504	$ 40,999	$ (1,611,117)	$ 2,310,387	6.66%	$ 12,988	22,044
Feb-22	3,921,504	$ -		(15,298)	(21,303)	(21,490)	(20,837)	3,830,421	$ 37,421	$ (1,573,696)	$ 2,256,725	6.66%	$ 12,675	21,514
Mar-22	3,830,421	$ -		(12,146)	(16,913)	(17,061)	(16,543)	3,758,109	$ 29,709	$ (1,543,987)	$ 2,214,122	6.66%	$ 12,408	21,061
Apr-22	3,758,109	$ -		(11,144)	(15,518)	(15,654)	(15,179)	3,691,759	$ 27,259	$ (1,516,728)	$ 2,175,031	6.66%	$ 12,182	20,676
May-22	3,691,759	$ -		(11,894)	(16,563)	(16,708)	(16,200)	3,620,944	$ 29,093	$ (1,487,635)	$ 2,133,309	6.66%	$ 11,957	20,295
Jun-22	3,620,944	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	3,543,497	$ 31,818	$ (1,455,817)	$ 2,087,680	6.66%	$ 11,715	19,884
Jul-22	3,543,497	$ -		(12,426)	(17,304)	(17,455)	(16,925)	3,469,514	$ 30,395	$ (1,425,422)	$ 2,044,092	6.66%	$ 11,467	19,464
Aug-22	3,469,514	$ -		(12,065)	(16,801)	(16,948)	(16,433)	3,397,680	$ 29,512	$ (1,395,910)	$ 2,001,770	6.66%	$ 11,229	19,059
Sep-22	3,397,680	$ -		(11,469)	(15,971)	(16,111)	(15,622)	3,329,394	$ 28,055	$ (1,367,855)	$ 1,961,539	6.66%	$ 11,000	18,670
Oct-22	3,329,394	$ -		(10,888)	(15,162)	(15,295)	(14,830)	3,264,569	$ 26,633	$ (1,341,222)	$ 1,923,347	6.66%	$ 10,782	18,301
Nov-22	3,264,569	$ -		(12,342)	(17,186)	(17,336)	(16,810)	3,191,089	$ 30,188	$ (1,311,034)	$ 1,880,055	6.66%	$ 10,556	17,917
Dec-22	3,191,089	$ -		(15,474)	(21,547)	(21,736)	(21,075)	3,098,963	$ 37,849	$ (1,273,185)	$ 1,825,778	6.66%	$ 10,285	17,457
Jan-23	3,098,963	$ -		(16,761)	(23,340)	(23,545)	(22,829)	2,999,171	$ 40,999	$ (1,232,186)	$ 1,766,985	6.66%	$ 9,971	16,925
Feb-23	2,999,171	$ -		(15,298)	(21,303)	(21,490)	(20,837)	2,908,088	$ 37,421	$ (1,194,765)	$ 1,713,323	6.66%	$ 9,659	16,395
Mar-23	2,908,088	$ -		(12,146)	(16,913)	(17,061)	(16,543)	2,835,776	$ 29,709	$ (1,165,056)	$ 1,670,720	6.66%	$ 9,392	15,941
Apr-23	2,835,776	$ -		(11,144)	(15,518)	(15,654)	(15,179)	2,769,426	$ 27,259	$ (1,137,797)	$ 1,631,629	6.66%	$ 9,165	15,556
May-23	2,769,426	$ -		(11,894)	(16,563)	(16,708)	(16,200)	2,698,611	$ 29,093	$ (1,108,704)	$ 1,589,907	6.66%	$ 8,941	15,176
Jun-23	2,698,611	$ -	$ -	(13,008)	(18,114)	(18,273)	(17,717)	2,621,164	$ 31,818	$ (1,076,886)	$ 1,544,278	6.66%	$ 8,699	14,764
Jul-23	2,621,164	$ -		(12,426)	(17,304)	(17,455)	(16,925)	2,547,181	$ 30,395	$ (1,046,491)	$ 1,500,690	6.66%	$ 8,451	14,344
Aug-23	2,547,181	$ -		(12,065)	(16,801)	(16,948)	(16,433)	2,475,347	$ 29,512	$ (1,016,979)	$ 1,458,368	6.66%	$ 8,212	13,939
Sep-23	2,475,347	$ -		(11,469)	(15,971)	(16,111)	(15,622)	2,407,061	$ 28,055	$ (988,924)	$ 1,418,137	6.66%	$ 7,983	13,550
Oct-23	2,407,061	$ -		(10,888)	(15,162)	(15,295)	(14,830)	2,342,235	$ 26,633	$ (962,291)	$ 1,379,944	6.66%	$ 7,766	13,181
Nov-23	2,342,235	$ -		(12,342)	(17,186)	(17,336)	(16,810)	2,268,756	$ 30,188	$ (932,103)	$ 1,336,653	6.66%	$ 7,540	12,797
Dec-23	2,268,756	$ -		(15,474)	(21,547)	(21,736)	(21,075)	2,176,630	$ 37,849	$ (894,254)	$ 1,282,376	6.66%	$ 7,269	12,338
Jan-24	2,176,630	$ -		(16,761)	(23,340)	(23,545)	(22,829)	2,076,838	$ 40,999	$ (853,255)	$ 1,223,583	6.66%	$ 6,955	11,805
Feb-24	2,076,838	$ -		(15,298)	(21,303)	(21,490)	(20,837)	1,985,755	$ 37,421	$ (815,834)	$ 1,169,921	6.66%	$ 6,643	11,275
Mar-24	1,985,755	$ -		(12,146)	(16,913)	(17,061)	(16,543)	1,913,442	$ 29,709	$ (786,125)	$ 1,127,317	6.66%	$ 6,376	10,822
Apr-24	1,913,442	$ -		(11,144)	(15,518)	(15,654)	(15,179)	1,847,092	$ 27,259	$ (758,866)	$ 1,088,226	6.66%	$ 6,149	10,437
May-24	1,847,092	$ -		(11,894)	(16,563)	(16,708)	(16,200)	1,776,278	$ 29,093	$ (729,773)	$ 1,046,505	6.66%	$ 5,925	10,056
Jun-24	1,776,278	$ -	$ -	-	(18,114)	(18,273)	(17,717)	1,711,839	$ 26,474	$ (703,299)	$ 1,008,540	6.66%	$ 5,704	9,681
Jul-24	1,711,839	$ -		-	(17,304)	(17,455)	(16,925)	1,650,282	$ 25,290	$ (678,009)	$ 972,273	6.66%	$ 5,497	9,331
Aug-24	1,650,282	$ -		-	(16,801)	(16,948)	(16,433)	1,590,513	$ 24,555	$ (653,454)	$ 937,059	6.66%	$ 5,299	8,994
Sep-24	1,590,513	$ -		-	(15,971)	(16,111)	(15,622)	1,533,697	$ 23,343	$ (630,111)	$ 903,586	6.66%	$ 5,108	8,671
Oct-24	1,533,697	$ -		-	(15,162)	(15,295)	(14,830)	1,479,759	$ 22,160	$ (607,951)	$ 871,808	6.66%	$ 4,927	8,363
Nov-24	1,479,759	$ -		-	(17,186)	(17,336)	(16,810)	1,418,622	$ 25,118	$ (582,833)	$ 835,789	6.66%	$ 4,739	8,044

Atlantic City Electric Company
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Installation Costs 15 Year Recovery

Month	Unamortized Beginning Balance		Additional Program Costs	Market Earnings Offset		Amortization 1	Amortization 2	Amortization 3	Amortization 4	Unamortized Ending Balance		Deferred Tax Activity		Accum Deferred Tax		Unamortized Ending Bal. net of Accum Deferred Tax	CCRF Rate Net-of-Tax		Estimated CCRF Net-of-Tax	CCRF Adjusted for Income Tax
Dec-24	1,418,622	$	-			-	(21,547)	(21,736)	(21,075)	1,341,970	$	31,492	$	(551,341)	$	790,629	6.66%	$	4,514	7,662
Jan-25	1,341,970	$	-			-	(23,340)	(23,545)	(22,829)	1,258,938	$	34,113	$	(517,228)	$	741,710	6.66%	$	4,253	7,218
Feb-25	1,258,938	$	-			-	(21,303)	(21,490)	(20,837)	1,183,154	$	31,135	$	(486,093)	$	697,061	6.66%	$	3,993	6,778
Mar-25	1,183,154	$	-			-	(16,913)	(17,061)	(16,543)	1,122,987	$	24,719	$	(461,374)	$	661,613	6.66%	$	3,771	6,400
Apr-25	1,122,987	$	-			-	(15,518)	(15,654)	(15,179)	1,067,781	$	22,681	$	(438,693)	$	629,088	6.66%	$	3,582	6,080
May-25	1,067,781	$	-			-	(16,563)	(16,708)	(16,200)	1,008,861	$	24,207	$	(414,486)	$	594,375	6.66%	$	3,396	5,763
Jun-25	1,008,861	$	-	$	-	-	-	(18,273)	(17,717)	962,536	$	19,032	$	(395,454)	$	567,082	6.66%	$	3,223	5,471
Jul-25	962,536	$	-			-	-	(17,455)	(16,925)	918,283	$	18,181	$	(377,273)	$	541,010	6.66%	$	3,075	5,220
Aug-25	918,283	$	-			-	-	(16,948)	(16,433)	875,315	$	17,653	$	(359,620)	$	515,695	6.66%	$	2,933	4,978
Sep-25	875,315	$	-			-	-	(16,111)	(15,622)	834,470	$	16,781	$	(342,839)	$	491,631	6.66%	$	2,796	4,745
Oct-25	834,470	$	-			-	-	(15,295)	(14,830)	795,695	$	15,930	$	(326,909)	$	468,786	6.66%	$	2,666	4,524
Nov-25	795,695	$	-			-	-	(17,336)	(16,810)	751,743	$	18,057	$	(308,852)	$	442,891	6.66%	$	2,530	4,295
Dec-25	751,743	$	-			-	-	(21,736)	(21,075)	696,638	$	22,639	$	(286,213)	$	410,425	6.66%	$	2,368	4,020
Jan-26	696,638	$	-			-	-	(23,545)	(22,829)	636,947	$	24,523	$	(261,690)	$	375,257	6.66%	$	2,181	3,701
Feb-26	636,947	$	-			-	-	(21,490)	(20,837)	582,465	$	22,383	$	(239,307)	$	343,158	6.66%	$	1,994	3,384
Mar-26	582,465	$	-			-	-	(17,061)	(16,543)	539,212	$	17,770	$	(221,537)	$	317,675	6.66%	$	1,834	3,113
Apr-26	539,212	$	-			-	-	(15,654)	(15,179)	499,524	$	16,305	$	(205,232)	$	294,292	6.66%	$	1,698	2,883
May-26	499,524	$	-			-	-	(16,708)	(16,200)	457,167	$	17,402	$	(187,830)	$	269,337	6.66%	$	1,564	2,655
Jun-26	457,167	$	-	$	-	-	-	-	(17,717)	429,114	$	11,525	$	(176,305)	$	252,809	6.66%	$	1,449	2,460
Jul-26	429,114	$	-			-	-	-	(16,925)	402,316	$	11,010	$	(165,295)	$	237,021	6.66%	$	1,359	2,307
Aug-26	402,316	$	-			-	-	-	(16,433)	376,297	$	10,690	$	(154,605)	$	221,692	6.66%	$	1,273	2,161
Sep-26	376,297	$	-			-	-	-	(15,622)	351,563	$	10,162	$	(144,443)	$	207,120	6.66%	$	1,190	2,020
Oct-26	351,563	$	-			-	-	-	(14,830)	328,082	$	9,647	$	(134,796)	$	193,286	6.66%	$	1,111	1,886
Nov-26	328,082	$	-			-	-	-	(16,810)	301,466	$	10,935	$	(123,861)	$	177,605	6.66%	$	1,029	1,747
Dec-26	301,466	$	-			-	-	-	(21,075)	268,097	$	13,709	$	(110,152)	$	157,945	6.66%	$	931	1,581
Jan-27	268,097	$	-			-	-	-	(22,829)	231,951	$	14,850	$	(95,302)	$	136,649	6.66%	$	818	1,388
Feb-27	231,951	$	-			-	-	-	(20,837)	198,959	$	13,554	$	(81,748)	$	117,211	6.66%	$	705	1,196
Mar-27	198,959	$	-			-	-	-	(16,543)	172,766	$	10,761	$	(70,987)	$	101,779	6.66%	$	608	1,032
Apr-27	172,766	$	-			-	-	-	(15,179)	148,733	$	9,874	$	(61,113)	$	87,620	6.66%	$	526	892
May-27	148,733	$	-			-	-	-	(16,200)	123,083	$	10,538	$	(50,575)	$	72,508	6.66%	$	444	754

PEPCO HOLDINGS INC. (PHI) POWER DELIVERY
SYSTEM CAPITAL STRUCTURES AND COST OF CAPITAL
&
JURISDICTIONAL AUTHORIZED/APPROVED & CURRENT CAPITAL STRUCTURES & COSTS OF CAPITAL

AUTHORIZED

COMPANY/LOB	JURISDICTION	SERVICE TYPE	TYPE OF CAPITAL	% OF TOTAL	COST RATE	PRE-TAX RATE OF RETURN	OVERALL RATE OF RETURN	AFTER-TAX COST OF CAPITAL	NOTES (EFFECTIVE DATES FOR RETURN ON EQUITY (ROE), RETURN ON DEBT & PREF STOCK, CAPITAL STRUCTURE %'S, ETC.)
ACE	NEW JERSEY	ELECTRIC	LONG-TERM DEBT	50.64%	6.71%	3.40%	3.40%	2.00%	* OVERALL RATE OF RETURN SETTLED USING %'s & RATES PROPOSED BY STAFF - SPECIFIC ROE NOT SETTLED
			TRUST PREFERRED	2.51%	7.84%	0.20%	0.20%	0.12%	COMPANY ONLY SETTLED ON THE OVERALL RATE OF RETURN - NOT THE INDIVIDUAL COMPONENTS OF IT.
			PREFERRED STOCK	0.63%	4.27%	0.03%	0.03%	0.03%	* AUTHORIZED RETURN ON DEBT & PREF. STOCK = SETTLED BASED ON COST RATES OF 6/30/03 CAPITAL STRUCTURE
			COMMON EQUITY	46.22%	9.75%	7.65%	4.51%	4.51%	* CAPITAL STRUCTURE %'S = SETTLED USING 6/30/03 CAPITAL STRUCTURE
			TOTAL	100.00%		11.28%	8.14%	6.66%	

CURRENT

COMPANY/LOB	JURISDICTION	SERVICE TYPE	TYPE OF CAPITAL	% OF TOTAL	COST RATE	PRE-TAX RATE OF RETURN	OVERALL RATE OF RETURN	AFTER-TAX COST OF CAPITAL	NOTES
ACE	NEW JERSEY	ELECTRIC	LONG-TERM DEBT	47.49%	5.94%	2.82%	2.82%	1.66%	* CAPITAL STRUCTURE AND COST RATES BASED ON 3/31/08 DATA
			TRUST PREFERRED	0.00%	0.00%	0.00%	0.00%	0.00%	
			PREFERRED STOCK	0.62%	4.24%	0.03%	0.03%	0.03%	
			COMMON EQUITY	51.89%	9.75%	8.59%	5.06%	5.06%	
			TOTAL	100.00%		11.44%	7.91%	6.75%	

USAGE (KWH)			Rate	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Avg	Winter	Summer
1000	Summer	0-750							750	750	750	750				3000			
		over 750							250	250	250	250				1000			
summer	Winter	0-500		500	500	500	500	500					500	500	500	4000			
winter		over 500		500	500	500	500	500					500	500	500	4000			
		Total		1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	12000	1000		
BILL ($)																			
Existing Rates																			
	Customer Charge		$2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 30.12			
	Summer	0-750	0.174401						$ 130.80	$ 130.80	$ 130.80	$ 130.80				$ 523.20			
		over 750	0.188298						$ 47.07	$ 47.07	$ 47.07	$ 47.07				$ 188.28			
	Winter	0-500	0.131575	$ 65.79	$ 65.79	$ 65.79	$ 65.79	$ 65.79					$ 65.79	$ 65.79	$ 65.79	$ 526.32			
		over 500	0.126086	$ 63.04	$ 63.04	$ 63.04	$ 63.04	$ 63.04					$ 63.04	$ 63.04	$ 63.04	$ 504.32			
	Total			$ 131.34	$ 131.34	$ 131.34	$ 131.34	$ 131.34	$ 180.38	$ 180.38	$ 180.38	$ 180.38	$ 131.34	$ 131.34	$ 131.34	$ 1,772.24	$ 147.69	$ 131.34	$ 180.38
Proposed Rates																			
	Customer Charge		$2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 2.51	$ 30.12			
	Summer	0-750	0.174574						$ 130.93	$ 130.93	$ 130.93	$ 130.93				$ 523.72			
		over 750	0.188471						$ 47.12	$ 47.12	$ 47.12	$ 47.12				$ 188.48			
	Winter	0-500	0.131748	$ 65.87	$ 65.87	$ 65.87	$ 65.87	$ 65.87					$ 65.87	$ 65.87	$ 65.87	$ 526.96			
		over 500	0.126259	$ 63.13	$ 63.13	$ 63.13	$ 63.13	$ 63.13					$ 63.13	$ 63.13	$ 63.13	$ 505.04			
	Total			$ 131.51	$ 131.51	$ 131.51	$ 131.51	$ 131.51	$ 180.56	$ 180.56	$ 180.56	$ 180.56	$ 131.51	$ 131.51	$ 131.51	$ 1,774.32	$ 147.86	$ 131.51	$ 180.56
Bill Impact ($)				$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ 0.17	$ 0.18	$ 0.18	$ 0.18	$ 0.18	$ 0.17	$ 0.17	$ 0.17	$ 2.08	$ 0.17	$ 0.17	$ 0.18
Bill Impact(%)				0.13%	0.13%	0.13%	0.13%	0.13%	0.10%	0.10%	0.10%	0.10%	0.13%	0.13%	0.13%	0.12%	0.12%	0.13%	0.10%

RIDER (BGS) continued

Basic Generation Service (BGS)

CIEP Standby Fee $0.000161 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

System Control Charge (SCC) $$x.xxxxxx per kWh
This charge provides for recovery of the Company's direct load control program as delineated in Tariff Rider DLC. This charge includes administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all electric customers.

Retail Margin $0.005377 per kWh
This charge is applicable to all customers taking service under BGS CIEP and those BGS-FP customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary or AGS Primary whose annual PLS for generation capacity is equal to or greater than 750 kW as of November 1 of each year. This charge includes administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT

EXHIBIT B

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

BPU Docket Nos. EO08050326 and EO07110881

TESTIMONY OF
STEPHEN L. SUNDERHAUF

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

BPU Docket Nos. EO08050326 and EO07110881

August 1, 2008

TESTIMONY OF

Stephen L. Sunderhauf

ON BEHALF OF
ATLANTIC CITY ELECTRIC COMPANY

Q. Please state your name, position and address.

A. My name is Stephen L. Sunderhauf. I am the Manager of Program Design and Evaluation for Pepco Holdings, Inc. ("PHI"). PHI is the indirect parent company of Atlantic City Electric Company ("ACE," "Atlantic" or the "Company"). My business address is Edison Place, 701 9th St., N.W., Washington, D.C. 20068-0001.

Q. Please describe your educational and professional background.

A. I currently serve as the Manager of the Program Evaluation Department within the Regulatory Group of PHI. My current responsibilities include the oversight of regulatory issues related to energy efficiency, conservation, demand response and renewable energy sources on behalf of the Potomac Electric Power Company, Delmarva Power & Light Company, and ACE. I have 26 years of professional experience within the U.S. electric utility industry, including more than 22 years at PHI, where I have served in a variety of capacities. I earned a B.A. degree in economics from Bucknell University, an M.S. degree in management from Carnegie-Mellon University, and a J.D. degree from the George Washington University Law School. I am a member of the Maryland Bar and the Association of Energy Services Professionals.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the Company's proposed demand response programs designed to reduce electricity demand during periods of high market prices. The two new proposed programs are as follows: 1) a residential remotely controllable smart thermostat program to permit the Company to reduce summer air conditioner load during peak periods, and 2) an Internet-based demand response platform to support larger-size (i.e. commercial and industrial) customer participation in the PJM demand response program. My testimony includes a description of ACE's proposed programs, projected benefits, projected participation levels, projected demand impact and projected costs, as well as Atlantic's vision of demand response programs in New Jersey. In addition, my testimony represents ACE's response to the Order that was issued by the Board on or about July 1, 2008 in connection with Docket No. EO08050326 (the "Order"). The Order directed electric utilities to submit proposals for demand response programs that could begin installation by June 1, 2009, if approved by the Board.

Q. Please provide a description for each of the proposed two new demand response programs.

A. <u>Residential Controllable Smart Thermostat Program</u>

ACE proposes to install remotely controllable smart thermostats at residential customers' homes with central air conditioners or heat pumps to enable the Company to reduce peak electricity demand during periods of high summer electricity use. The program will be created in a manner that comports to the requirements of the PJM demand response wholesale market. Residential customer participation will be voluntary and incented by the one-time payment of $50 and receipt of a smart thermostat. The deployed remotely controllable thermostats are expected to have the following minimal capabilities: 1) operate as programmable thermostats for customers; 2) be uniquely addressable by ACE; 3) have the capability of communicating in the near term through cellular or radio communications and in the future through an Automated Meter Infrastructure ("AMI") System; and 4) be capable of reducing central air conditioner and electric heat pump system load through both temperature setback and cycling options.

Internet-Based Demand Response Platform

ACE proposes to establish an Internet platform for load curtailments to motivate non-residential customers to participate in the PJM load response programs by providing a convenient method to do so. The number of eligible customers will increase significantly as AMI is deployed, providing the PJM required hourly energy data. Prior to the deployment of an AMI system, individual customers without interval metering may elect to receive an interval meter at their expense. Program participants will receive energy use information, ACE Zonal PJM Locational Marginal Prices ("LMPs") for energy, and load reduction calculations through the Internet Platform. The minimum size for customer participation will be set at 100kW to correspond with existing PJM market rules. ACE will aggregate the load of smaller sized participants to facilitate their participation in the market. Customer incentives will be based upon the load reductions that are achieved. Atlantic proposes to share 70% of the earnings with participants and retain 30% to offset program costs. Payment to customers through ACE will appear as credits on the customer's electric distribution bill. Participants will have the option at any time to exit this Program and participate in any PJM demand response program through a competitive Curtailment Service Provider, a Load Serving Entity, or directly with PJM. ACE expects to enroll 10MW of peak demand reductions in this program after three years.

Q. How do Atlantic's proposed Demand Response programs address the Board's Order in terms of their availability to all customer classes?

A. ACE has sought to rapidly identify demand response initiatives that could be available to all customer segments in the near-term. The proposed residential direct load control program will be available to residential customers with central electric air conditioners and/or heat pumps. The proposed demand response Internet Platform will serve as a portal to the PJM demand response market opportunities for larger customers. ACE has described two additional demand response programs that it has proposed in its "Blueprint for the Future" (the "Blueprint") filing, BPU Docket No. EO07110881. These programs are a dynamic pricing program enabled through the deployment of AMI and a small commercial customer direct load control program similarly enabled by AMI.

Q. What is ACE's vision of the future of demand response programs in New Jersey?

A. ACE articulated its overall vision for the future of demand response activities in New Jersey in the Blueprint filing referenced above. Over time, ACE envisions a future path where the deployment of advanced meters for all customers directly support communications with demand response enabling equipment, such as smart thermostats, and supports the availability of dynamic pricing for all customers. Dynamic pricing will motivate New Jersey electricity consumers to lessen their electricity consumption during high priced periods and will serve as an incentive for consumers to permit ACE to install demand response enabling equipment.

Q. Please describe the Company's planning process for direct load control programs in New Jersey.

A. The Company provided details for its proposed direct load control programs for the period 2009 through 2012 in its Blueprint filing and has adjusted the installation start-time to begin in 2009. The process formally began on May 29, 2006 when the Board issued an order approving a settlement regarding the future operation of existing New Jersey direct load control programs (the "May 2006 Order"). In the May 2006 Order, the Board directed New Jersey utilities to work with Board Staff and the Division of Rate Counsel to evaluate existing utility direct load control programs and to recommend the "future direction" of the programs. In consultation with Staff and the Division of Rate Counsel, the utilities hired Summit Blue Consulting, LLC ("Summit Blue") to work with the parties to develop recommendations regarding these direct load control programs. On June 7, 2007, in conformance with the May 2006 Order, ACE, Jersey Central Power and Light Company, and Public Service Electric & Gas Company, jointly filed a proposal, "New Jersey Direct Load Control Program Proposal," to expand their existing direct load control programs in the manner recommended by Summit Blue. That filing stated that each utility would subsequently submit its company-specific plan to the Board for consideration. On August 20, 2007, Atlantic filed its company-specific plan in connection with Docket No. EO06040297. Proposed program details for the period 2009 through 2012 were presented in the Blueprint filing. The Company has revised the start date of its prior proposal from late 2008 to late 2009.

Q. Does the Company plan to offer a cycling switch as an option, in place of the controllable smart thermostat?

A. Yes. ACE will permit customers to choose the installation of a smart thermostat or an outdoor cycling device, depending upon a customer's preference. In the event that a customer chooses a smart thermostat, but that device is not compatible with the customer's HVAC unit or if a communication signal is unable to reach the smart thermostat, the customer will be offered an outdoor direct load control cycling switch.

Q. What are the projected participation levels in the residential controllable smart thermostat program also referred to as Direct Load Control ("DLC") programs?

A. The targeted residential deployment rates are included in Table 1 below and are consistent with projections contained in the Summit Blue report, "New Jersey Central Air Conditioner Cycling Program Assessment - Final Report," dated June 4, 2007, that approximately 17% of eligible customers will participate in the program.

Table 1

ACE Residential DLC Program Deployment Schedule

Year	2009	2010	2011	2012	2013
Incremental Participants	2,600	9,900	9,900	9,900	9,900
Total Participants	2,600	12,500	22,400	32,300	42,200

Q. What are the peak electricity demand impacts for the residential controllable smart thermostat program?

A. The targeted residential demand impacts are included in Table 2 below and are consistent with Summit Blue's projections.

Table 2
ACE Residential DLC Program Peak Demand Impact
(MW-Year End))

Year	2009	2010	2011	2012	2013
Incremental	3.12	11.88	11.88	11.88	11.88
Cumulative	3.12	15.00	26.88	39.76	50.64

Q. How do the goals set by the Board in the Order compare to targeted MW reductions proposed by the Company?

A. The total MW impact proposed by ACE represents approximately 50MW reduction for the residential controllable smart thermostat program over a five year period and an additional 10MW reduction over three years for the Internet-based demand response platform program. This proposal is expected to provide approximately 12.4 MW by the end of the first energy year (June 1, 1009 to May 31, 2010) and approximately 34.2MW by the end of the third energy year. Note that the Energy Year is defined as the PJM planning year period of June 1 to May 31. The reductions contained in Table 2 are presented on a calendar year basis. The goals set by the Board call for 36MW in the first energy year and an additional 36MW by the end of the third energy year. The deployment and impact values for the proposed residential controllable smart thermostat program are consistent with those recommended by Summit Blue.

Q. Why is the Company unable to achieve the MW goals set by the Board in the Order?

A. As noted above, the Company's objective in developing its demand response programs in response to the Board's July 1, 2008 Order is to obtain the maximum MW reductions achievable based upon the most reasonable and reliable data available to it at this time. For that reason, the Company's proposed residential controllable thermostat program is based upon the actual data collected and conclusions reached by Summit Blue, rather than rely upon hypothetical customer participation levels that may or may not be achievable. ACE believes that its reliance on such verifiable data is consistent with the Board's intent and directive as set forth in ordering paragraph 2 of the "EDC Approach" in the Order. To the extent that further review and comment can provide a sound basis for further enhancing the Company's program participation, Atlantic is open to having those discussions. Further, the implementation of new demand response programs requires significant lead time and is a complex undertaking that requires sufficient time to competitively select equipment vendors and installers, recruit customers, and establish the internal utility processes and procedures necessary to implement successful programs. ACE has described its overall plan for reducing peak electricity demand through demand response programs in its Blueprint filing. A critical component of this plan is the provision of dynamic pricing that is supported through the installation of an AMI system. The Company will implement its proposed residential DLC program and the larger customer Internet demand response platform as rapidly as possible after Board approval to do so.

Q. What are the projected program costs for the proposed new residential DLC program?

A. The program budget for the proposed new residential DLC program is shown in Table 3 below. Program budgets will be revised after program vendors are competitively selected and vendor contract negotiations are completed.

Table 3
ACE Residential DLC Program Budget ($)

Category	**2009**	**2010**	**2011**	**2012**	**2013**	**Total**
Equipment Expense						
T-Stats.	780,000	2,970,000	2,970,000	2,970,000	2,970,000	12,660,000
LR Meters	30,000	0	0	0	0	30,000
LR Feeders	195,000	195,000	195,000	195,000	195,000	975,000
Subtotal	*1,005,000*	*3,165,000*	*3,165,000*	*3,165,000*	*3,165,000*	*13,665,000*
O&M						
Marketing	46,000	32,500	32,500	32,500	32,500	176,000
Incentive	130,000	495,000	495,000	495,000	495,000	2,110,000
Maintenance	9,000	92,000	92,000	92,000	92,000	377,000
LR Mont.	90,000	46,000	46,000	46,000	46,000	274,000
Subtotal	*395,000*	*635,500*	*635,500*	*635,500*	*635,500*	*2,937,000*
Total	**1,280,000**	**3,830,500**	**3,830,500**	**3,830,500**	**3,830,500**	**16,602,000**

Q. Please provide a brief description of the program elements included in the above Table 3.

A. ACE has developed a program budget based upon the deployment schedule contained in Table 1. Actual expenditures will vary based upon vendor selection and negotiations, and customer participation rates. A brief description of each program element is provided below:

a. *Smart Programmable Thermostats* – Summit Blue estimates the cost per thermostat to equal $200 for capital and $100 for installation.

b. *Load Research Meters* – One hundred whole house load research meters, providing adequate sampling for a residential control group and adequate sampling of participants.

c. *Load Research Feeders* – ACE has included funds to support the monitoring of three feeders so that the feeder level impact of deployed smart thermostats or direct load control equipment can be monitored. The Company plans to install three phase metering on each of the monitored feeders and to expand this monitoring capability as the program is expanded.

d. *Marketing expenses* will be incurred for direct recruitment materials, mailing expense, and the handling of customer inquiries.

e. *Incentive amounts* are assumed to be $50 per participant, as recommended by Summit Blue. Additional incentive amounts may be required if targeted market penetration is not achieved. If additional incentive amounts are required, ACE will petition the Board for an increase in incentive payments.

f. *Annual program maintenance expense* is estimated based upon existing annual ACE Peak Savers Club maintenance expense.

g. *Load research monitoring expense* represents the additional expense to retrieve and store program related load research data.

Q. What are the projected program costs for the proposed new Internet-Based Demand Response Platform?

A. The projected budget for the proposed new Internet-Based Demand Response Platform is shown in Table 4 below. Program budgets will be revised after program vendors are competitively selected and vendor contract negotiations are completed.

Table 4
ACE Demand Response Internet Platform Budget

Year	Utility Admin.	Marketing	Outside Services	Equipment Expense	Evaluation	Total $ on-Inc.	Incentives	Total $ Program
1	$30,000	$40,000	$25,000	$170,000	$0	$265,000	Mkt.	$265,000
2	$20,000	$20,000	$25,000	$0	$0	$65,000	Mkt.	$65,000
3	$20,000	$20,000	$25,000	$0	$12,000	$77,000	Mkt.	$77,000
Total	**$70,000**	**$80,000**	**$75,000**	**$170,000**	**$12,000**	**$407,000**	**Mkt.**	**$407,000**

Q. Is the proposed new residential controllable smart thermostat programs cost-effective?

A. As noted in Summit Blue's final Report dated June 4, 2007, Table 6-2 page 64, the proposed new residential controllable smart thermostat program is projected to be cost-effective under both the Total Resource Test ("TRC") and the Rate Impact Test ("RIM"). Table 5 contains the costs and benefits for the program conducted by Summit Blue, based upon a 15-year planning period.

Table 5

	Residential RIM	**Residential TRC**
Benefits	$54,438,000	$57,438,000
Costs	$17,352,000	$3,591,000
Benefit/Cost	3.31	16.00
Net Benefits	$40,087,000	$53,848,000

Q. How does ACE propose to operate the proposed new residential controllable smart thermostat program?

A. ACE proposes a 50% percent cycling program whereby a participating residential customer's air conditioner compressor will by cycled off for 15 minutes of each half-hour period. Participants may override cycling events at any time and may drop out of the program at any time. ACE will evaluate other cycling options during the initial roll-out of the programs to increase peak demand reduction and/or improve customer adoption rates. ACE will seek Board authorization for any programmatic change. In addition, cycling may be initiated by the Company for any of the following reasons: 1) to test cycling equipment; 2) in response to a PJM dispatcher request to activate the program; 3) in response to local ACE electric system constraints; or 4) in response to regional energy market prices. The Company will attempt to minimize customer program attrition by initiating cycle events only when necessary for any of the reasons listed above. The cycling option proposed above for the new program is similar to the cycling option currently being implemented under the existing Peak Savers Club program.

Q. Will the existing Peak Savers Club program participants be given the opportunity to participate in the new proposed residential controllable smart thermostat program?

A. As the new program is implemented, the existing residential Peak Savers Club participants will have the option to continue with their current program or participate in the new cycling program and receive the benefits of the new program. At the time this testimony is being offered, there are approximately 22,000 residential Peak Savers Club participants.

Q. What is ACE's proposed schedule for implementing the proposed new residential controllable smart thermostat program?

A. ACE proposes the following schedule:

a. Board Approval: 4^{th} Quarter (November) 2008;

b. Equipment Vendor Selection: 1^{st} Quarter 2009;

c. Installer Vendor Selection: 1^{st} Quarter 2009;

d. Launch Participant Recruitment: 2^{nd} Quarter 2009; and

e. Start Date of Equipment Installation: 2^{nd} Quarter (June) 2009.

This supports the Procedural Schedule that was attached to the Order as Exhibit A (page 6) for residential controllable smart thermostat program only. ACE suggests that the Internet-Based Demand Response Platform be implemented by mid-2009, assuming Board approval is received in November 2008.

Q. Does ACE intend to use ACE employees or outside contractors to deliver the proposed programs?

A. The Company intends to use ACE employees and outside contractors to deliver the proposed programs. As noted previously, vendors/contractors will be selected on a competitive basis for the scope of work specified. ACE will rely upon internal employees for program administration and outside contractors for equipment installations.

Q. How does the Company plan to market the proposed programs to its customers?

A. ACE has not had sufficient time to prepare a detailed marketing plan for the recommended programs. A proposed marketing plan will be provided to the Board at a later date. ACE envisions the use of separate direct mail pieces for customers, information provided together with monthly customer bills, information presented on ACE's Internet site, use of the local media through informational stories, and in-person customer presentations.

Q. Has PHI received approval to implement similar DLC programs in its other jurisdictions?

A. Yes. The Maryland Public Service Commission recently approved the Company's request for permission to implement various measures designed to help customers reduce their peak energy consumption by Order dated April 18, 2008 (docketed as Case No. 9111) concerning Delmarva Power and Light Demand Response Program, and Order dated April 18, 2008 (docketed as Case No. 9111) concerning Potomac Electric Power Company Demand Response Program. At the heart of those measures is a residential DLC program similar to that being proposed herein for ACE's New Jersey customers. PHI is taking the steps necessary to begin equipment installations in early 2009.

Q. How does ACE plan to use PJM market earnings, assuming participation in those markets?

A. ACE proposes to use PJM market earnings to offset utility program costs through participation in the PJM demand response market. ACE recommends that BGS supplier rules for new utility-sponsored DLC programs be modified to permit

ACE to capture all direct PJM market incentives to offset and lessen ACE's DLC program costs for customers and/or provide additional incentives to program participants. Such a modification will permit Atlantic to bid the demand response resource into the forward PJM Reliability Pricing Model Base Residual Auction, the annual Interruptible Load for Reliability (or "ILR") market, and to capture energy market earnings. Prior to ACE's ability to directly capture these financial benefits, the Company will use the program to participate in the ILR market and PJM energy markets, but any direct market benefits will flow to BGS suppliers. Participating in the PJM forward capacity markets prior to this rule change will create financial risk for utility customers that is not offset by capacity market payments to the utility.

Q. Will a Tariff Rider be necessary?

A. Yes. Atlantic requests that specific program operational rules and participation requirements be included as a rider to the Company's residential rate tariffs. The new program will be designed to operate in a manner that permits the Atlantic to operate the program in conformance with the existing PJM demand response market. ACE's proposed rate rider will be submitted to the Board for approval as part of a compliance filing once the Company receives Board approval to implement the proposed new residential DLC program. A draft of the proposed tariff rider is included as Schedule SLS-1 to this testimony. In addition, the testimony of Joseph F. Janocha, Regulatory Affairs Manager in the Rates and Technical Services Section of PHI, will address proposed cost recovery and the rate impact on customers.

Q. What is ACE requesting of the Board at this time?

A. As more fully described in the Petition filed by Atlantic along with this testimony, ACE is requesting that the Board approve the Company's proposed new residential controllable smart thermostat program and Internet-based platform along with corresponding cost recovery during November 2008 so that the Company can begin equipment installation by June 1, 2009.

Q. What are the benefits of implementing the proposed new residential controllable smart thermostat program during 2009 and not waiting for the proposed deployment of AMI?

A. Implementing the proposed residential controllable smart thermostat program during 2009 will allow customers to begin receiving the benefits of the program earlier. Near-term energy and capacity prices will be lower for all of ACE's customers and, over the long-run, customer electric supply costs will be reduced. Near-term regional supply constraints will be lessened during periods of high summer electricity load and the likelihood of voltage reductions or rotating load shedding will be lessened. Construction of new generating equipment may be deferred and/or avoided. As noted previously, this is a cost effective program for New Jersey electricity consumers.

Q. Does this conclude your testimony?

A. Yes, it does.

RIDER "DLC"
DIRECT LOAD CONTROL RIDER

AVAILABILITY

This rider is applied to and is a part of Rate Schedule RS when a distribution customer volunteers for this demand response resource program subject to the provisions listed below.

GENERAL PROVISIONS

1. The customer will allow the Company to install, own, and maintain a smart thermostat(s) and associated equipment on the customer's central air conditioner or central heat pump equipment for the purpose of the Company's cycling control over the operation of those appliances as described below.

2. Customer volunteering for the program will be subject to the following program:

Rate Schedule	Cycling Program	Program Description
RS	50% Cycling Program	Participating customer's air conditioner compressor will be cycled off for 15 minutes of each half hour period

3. The Company may exercise cycling control whenever required for any of the following reasons:
   1) to test cycling equipment,
   2) in response to a PJM dispatcher request to activate the program,
   3) in response to local supply constraints, or
   4) in response to regional energy market prices.

   Participant override of cycling events will be limited to two events annually and are not permitted during PJM initiated cycling events.

4. Customers may only participate in one direct load control program at a time.

CONTRACT TERMS AND BILLING

1. The customer will receive a One Time Enrollment Installment Credit as specified in the table below for participating in the program. The customer will also receive a smart thermostat installed at no expense. In return, the participants will be required to remain enrolled in the program option for at least one year. The Enrollment Credit will be credited to the participant after the cycling equipment has been installed.

Rate Schedule	One Time Enrollment Installment Credit
RS	$50.00

2. Cost recovery is established through the System Control Charge ("SCC") provided for in Rider BGS.

3. The Customer holds the Company harmless for any damages resulting from participation in the program.

EXHIBIT C

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

BPU Docket Nos. EO08050326 and EO07110881

BRATTLE REPORT

Quantifying Customer Benefits
from Reductions in Critical Peak Loads from
PHI's Proposed Demand-Side Management Programs

Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs

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Prepared for

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September 21, 2007

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.[1] 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*;[2] 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.[3]. In one scenario, customers can voluntarily elect to enroll in a CPP rate structure, resulting in 20 percent of eligible customers participating.[4] In the alternative scenario, CPP is the default (but not mandatory) rate structure, resulting in 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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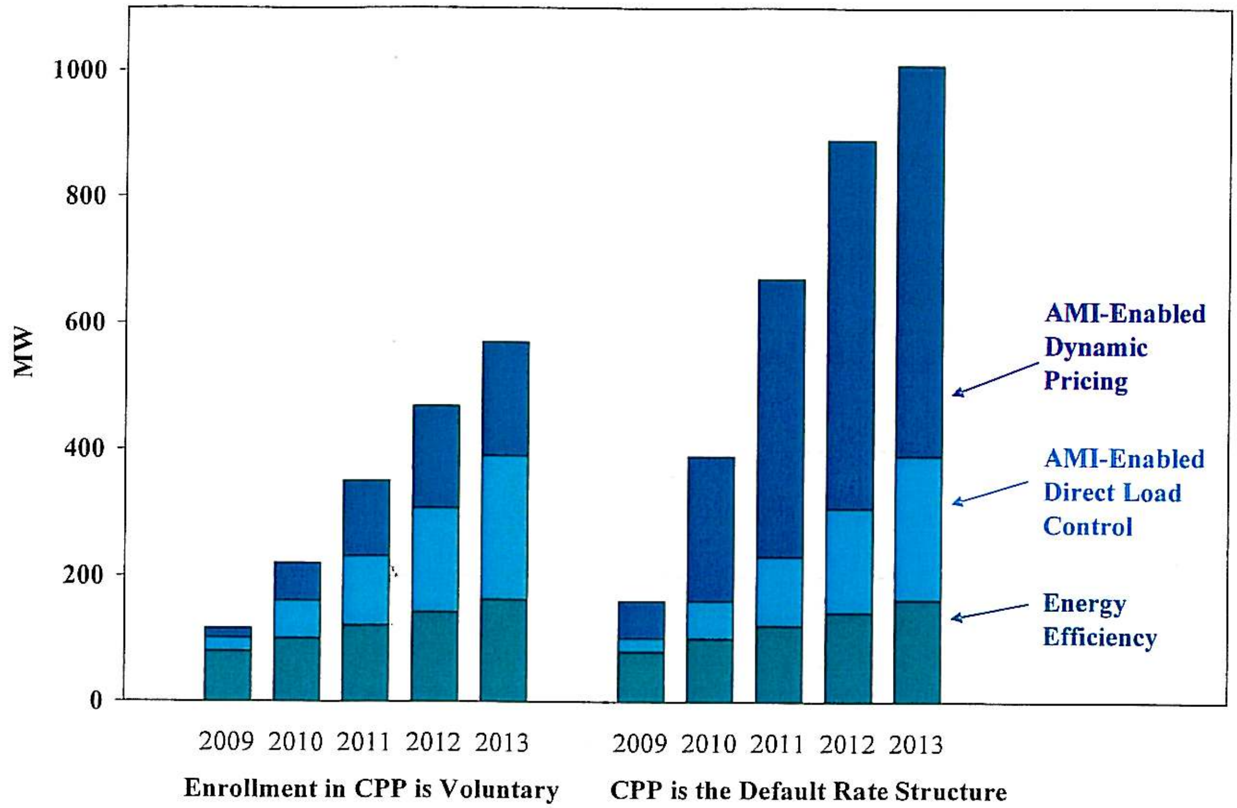
[1] PHI is selling its Virginia electric distribution service territory.

[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. (SMPPI). Board members of SMPPI 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.

Figure 1.1. Estimated Peak Load Reductions from PHI's Proposed DSM Programs (MW)

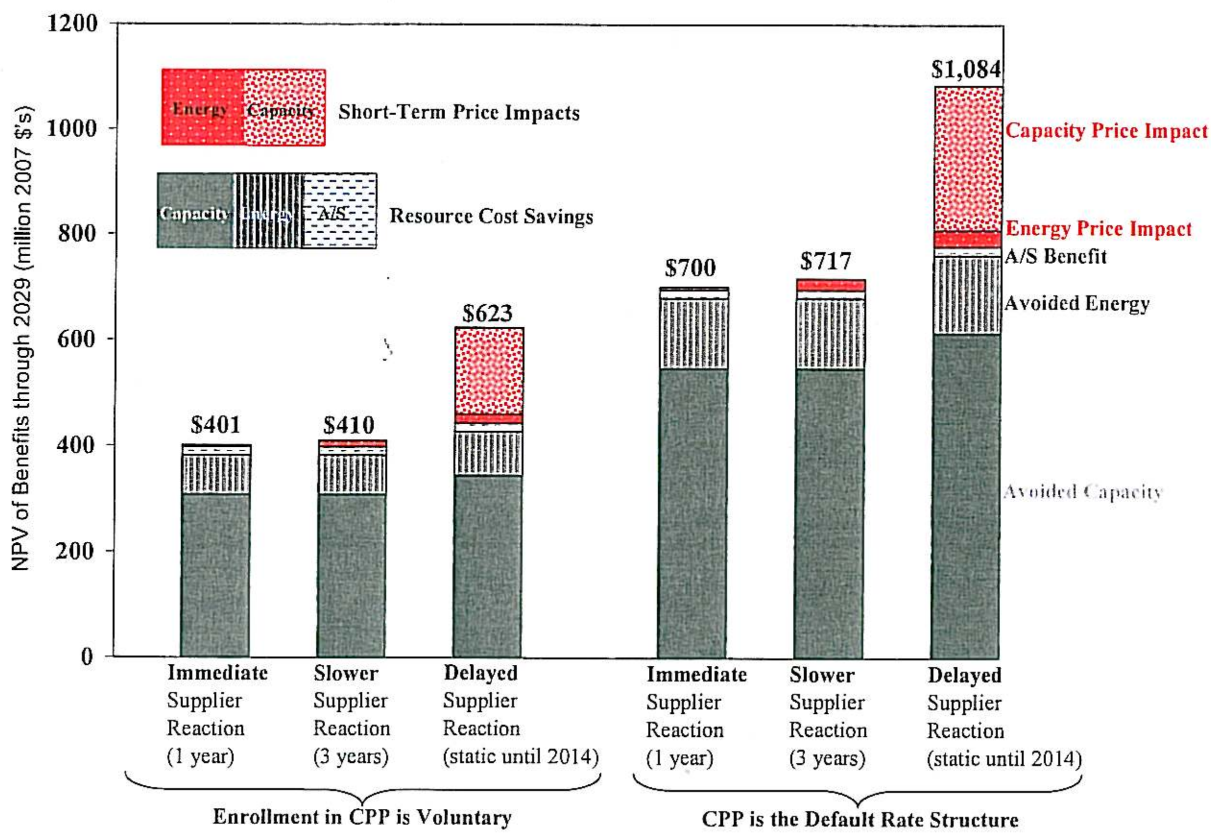


Reducing peak load benefits customers in several ways, including: (1) providing "resource cost savings" by reducing the quantity of capacity, energy, and ancillary services that customers must buy (or enabling them to sell those products); (2) creating "short-term market price impacts," *i.e.*, depressing 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.[5]
- 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.[6] The scenario was constructed to demonstrate the potential value of DSM in a severely supply-constrained situation.

[6] 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.[7]

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 of 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.[8]
- The "Slower Supplier Reaction" scenario is similar to the Immediate scenario except that short-term price impacts last for three-years before

[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.

[8] See "2008/ 2009 RPM Base Residual Auction Results," PJM Docs #428082, July, 2007.

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

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[9] See FERC Order on Rehearing and Clarification and Accepting Compliance Filing, Docket No. ER05-1410-002, *et al.*, paragraph 90, issued on June 25, 2007.

[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.

(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.[12] 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 retail provider 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

[12] ISO-NE's Demand-Response Reserve Pilot Program is discussed in section 6.3 of ISO-NE'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.[13] 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.[14] 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).[15] 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.

[15] See, for example, PJM's RPM Training Materials, Module D – Supply in RPM, http://www.pjm.com/markets/rpm/downloads/training/module-d.pdf

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

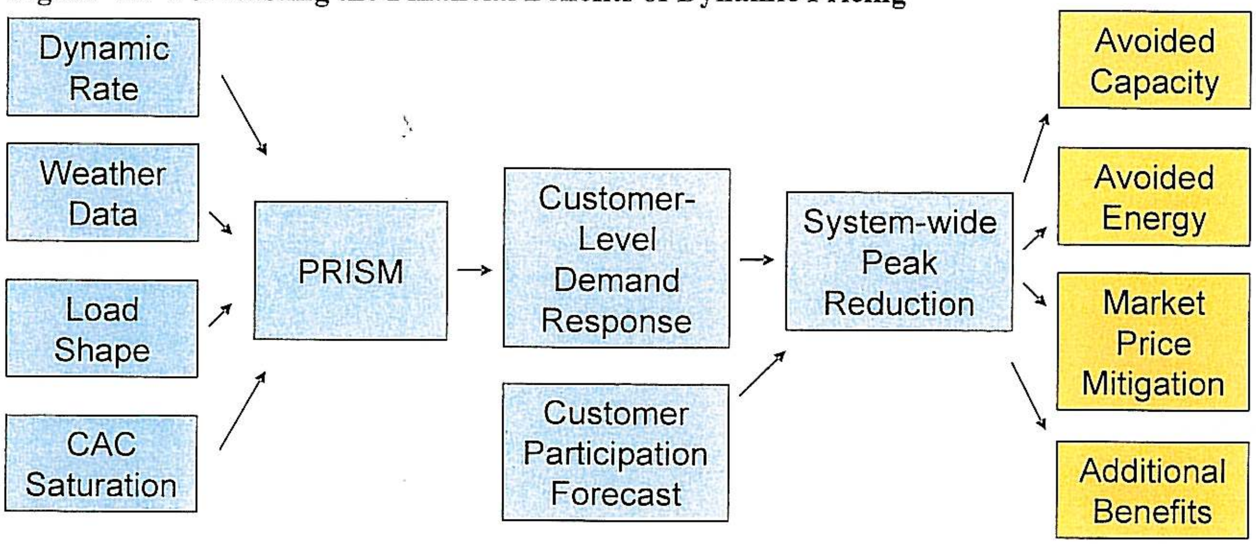
Deployment of AMI will allow PHI to provide dynamic rates to all of its distribution customers.[16] This is expected to yield additional significant reductions in peak demand beyond those that would be achieved through energy efficiency and direct load control programs alone. Specifically, dynamic pricing would allow PHI to provide customers with 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



4.2. DESCRIPTION OF PRISM

PRISM was developed during the California SPP.[17] 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.

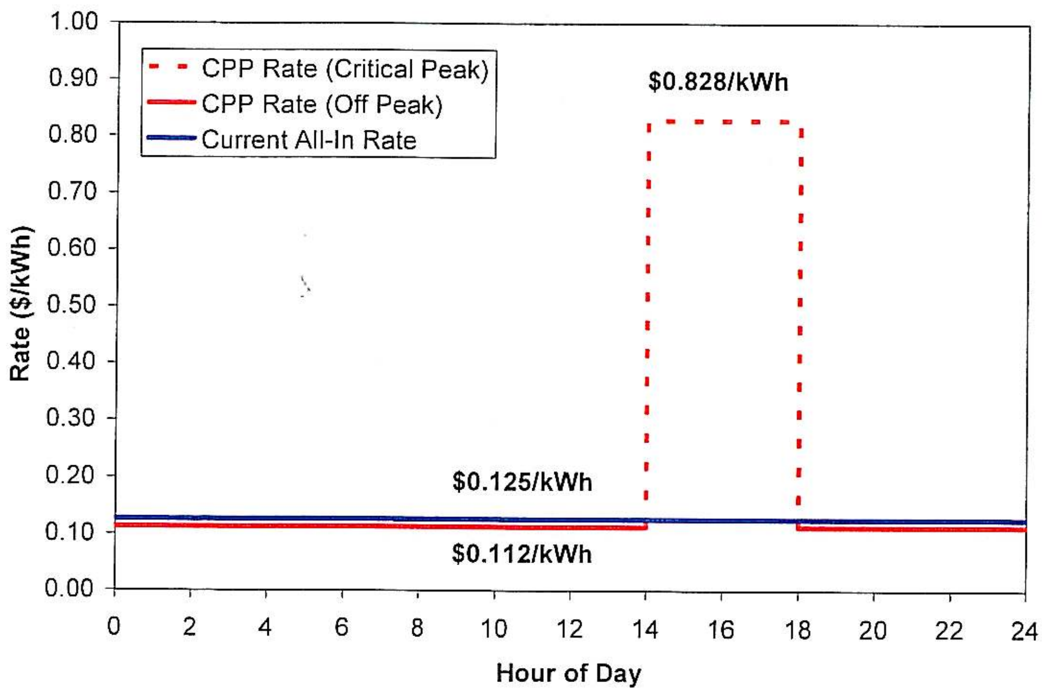
[17] For more information on the California SPP, see CRA International, "Impact Evaluation of the California Statewide Pricing Pilot," March 16, 2005. (http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005-03-24_SPP_FINAL_REP.PDF). See also Ahmad Faruqui and Stephen George, "Quantifying Customer Response to Dynamic Pricing," The Energy Journal, May 2005.

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 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 4.2.

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



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.[18] 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.

Table 4.1. Summary of CPP Rates ($/kWh)

	Existing All-In Rate	New CPP Rate	
	All Hours	Critical Peak	Off Peak
Pepco DC			
Residential	0.125	0.828	0.112
C&I	0.160	1.055	0.143
Pepco MD			
Residential	0.158	1.041	0.141
C&I	0.147	0.969	0.131
Delmarva DE			
Residential	0.143	0.946	0.128
C&I	0.115	0.758	0.103
Delmarva MD			
Residential	0.145	0.954	0.129
C&I	0.166	1.096	0.149
Atlantic City			
Residential	0.165	1.088	0.148
C&I	0.163	1.074	0.146

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.

[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.

[20] Pepco DC Rates and Regulatory Practices Group, "Rate Schedules for Electric Service in the District of Columbia," July 2007.

[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.

Table 4.2. Average Residential Load Shapes (June – September)

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Avg Hrly Critical Peak Consumption (kWh/hr)	1.91	2.90	1.92	2.48	2.13
Avg Hrly Off Peak Consumption (kWh/hr)	1.42	1.52	1.10	1.25	1.09

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.

Table 4.3. Average Non-Interval Meter C&I Load Shapes (June - September)

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Avg Hrly Critical Peak Consumption (kWh/hr)	17.90	18.20	8.06	4.20	4.97
Avg Hrly Off Peak Consumption (kWh/hr)	12.47	12.03	5.43	2.99	3.18

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

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Rate Schedule	"R"	"R"	"R"	"R"	"RS"
Avg Summer Bill ($/Month)	132	178	118	133	133
All-In Rate ($/kWh)	0.125	0.158	0.145	0.143	0.165

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 numbers previously shown in Table 4.3. 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

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Rate Schedule	"GT LV"	"MGT LV II"	"SGS-S I"	"MGS-S"	"MGS-S"
Avg Summer Bill ($/Month)	1,469	1,303	665	253	382
All-In Rate ($/kWh)	0.160	0.147	0.166	0.115	0.163

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

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Residential					
CAC	45%	66%	42%	42%	N/A
Heat Pump	11%	19%	11%	11%	N/A
Total	56%	84%	53%	53%	55%
C&I					
Total	97%	97%	97%	97%	97%

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.[23] 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

[23] 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 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.[24]

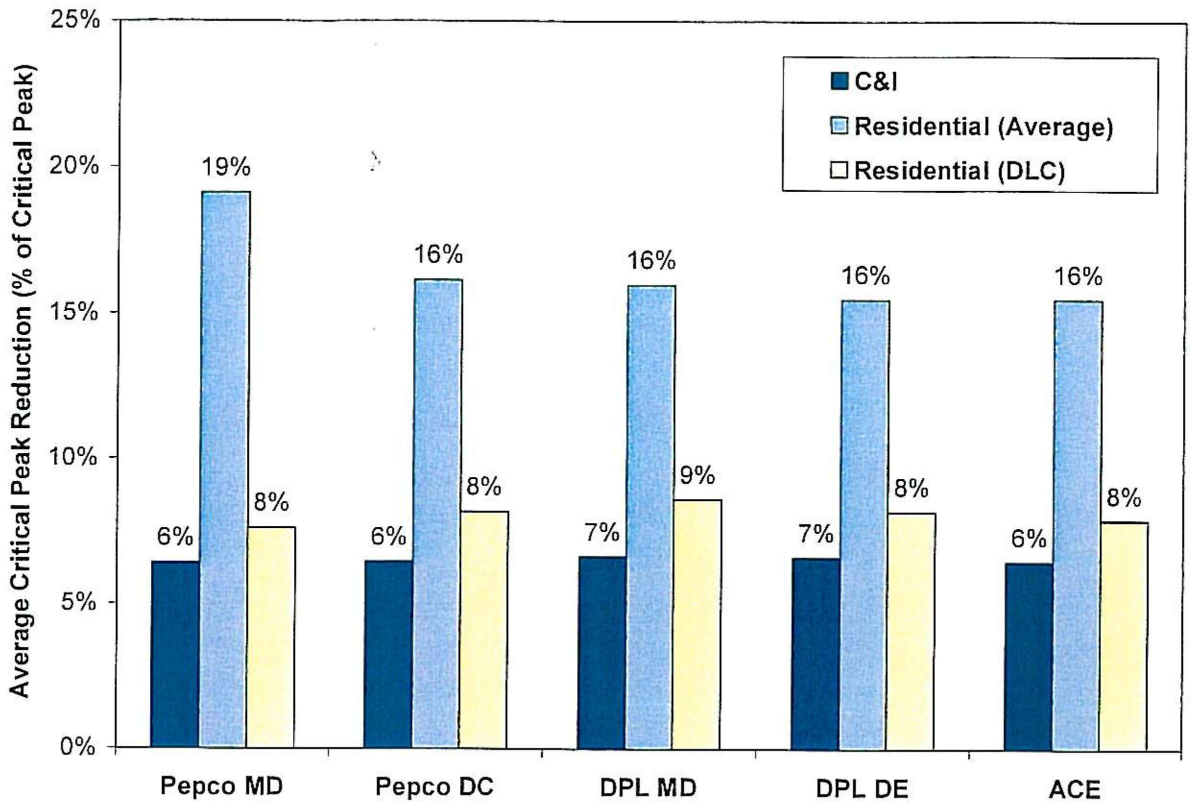
A share of PHI's customers will be participating in a direct load control (DLC) program. Through this program, PHI would control the participating customers' CAC systems through a device called a "smart thermostat" and would have the ability to reduce the customers' CAC load on peak days through the 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.

[24] See CRA International, "California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update," June 2006.

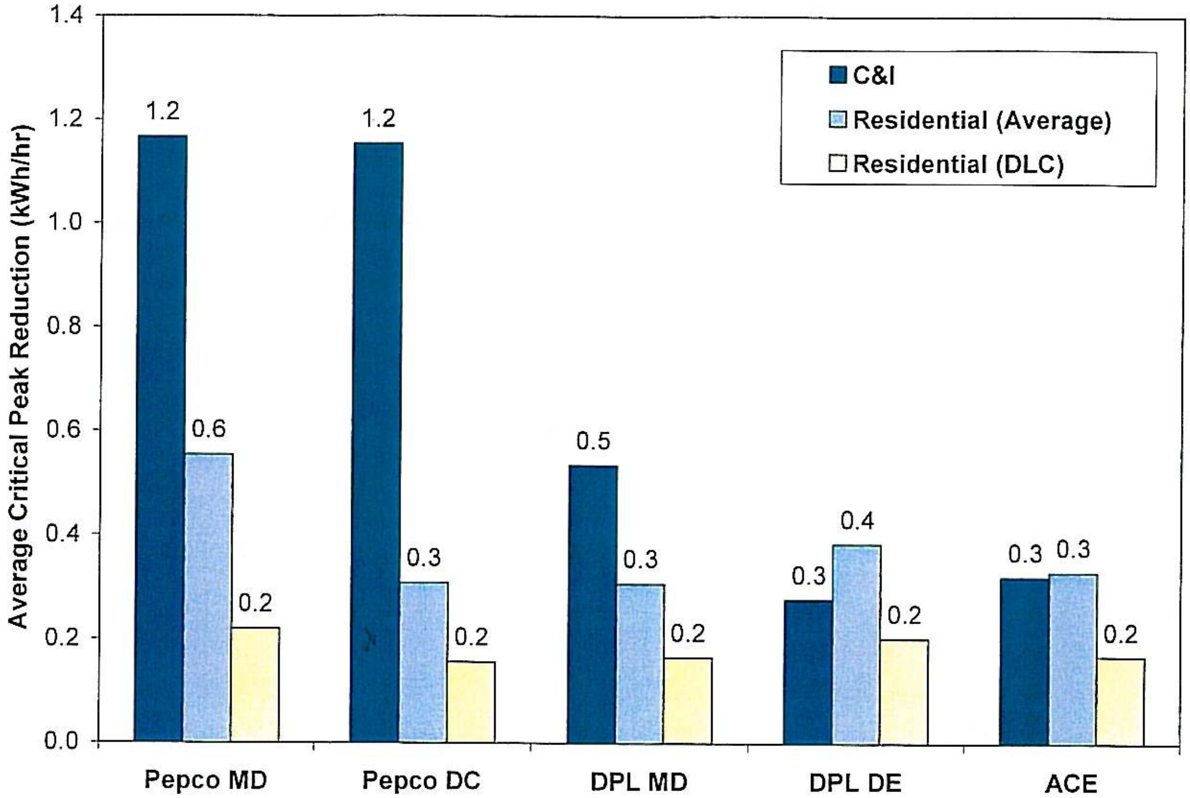
[25] For example, customers could refrain from running their clothes dryers until after the critical peak period ends. This would represent a peak demand reduction incremental to any reduction that would be attributable to the DLC program, which only has an impact on load created by the CAC system.

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.

Figure 4.4. Expected Average Critical Peak Reductions (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.

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

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
Residential					
Total	211,220	469,138	169,993	262,684	474,921
Annual Growth Rate	2.0%	0.8%	1.4%	0.9%	1.6%
C&I					
Total (Non-Interval)	24,704	45,248	27,312	32,625	53,096
Annual Growth Rate	0.9%	0.5%	1.4%	1.3%	1.0%

4.4.2. AMI Deployment Schedule

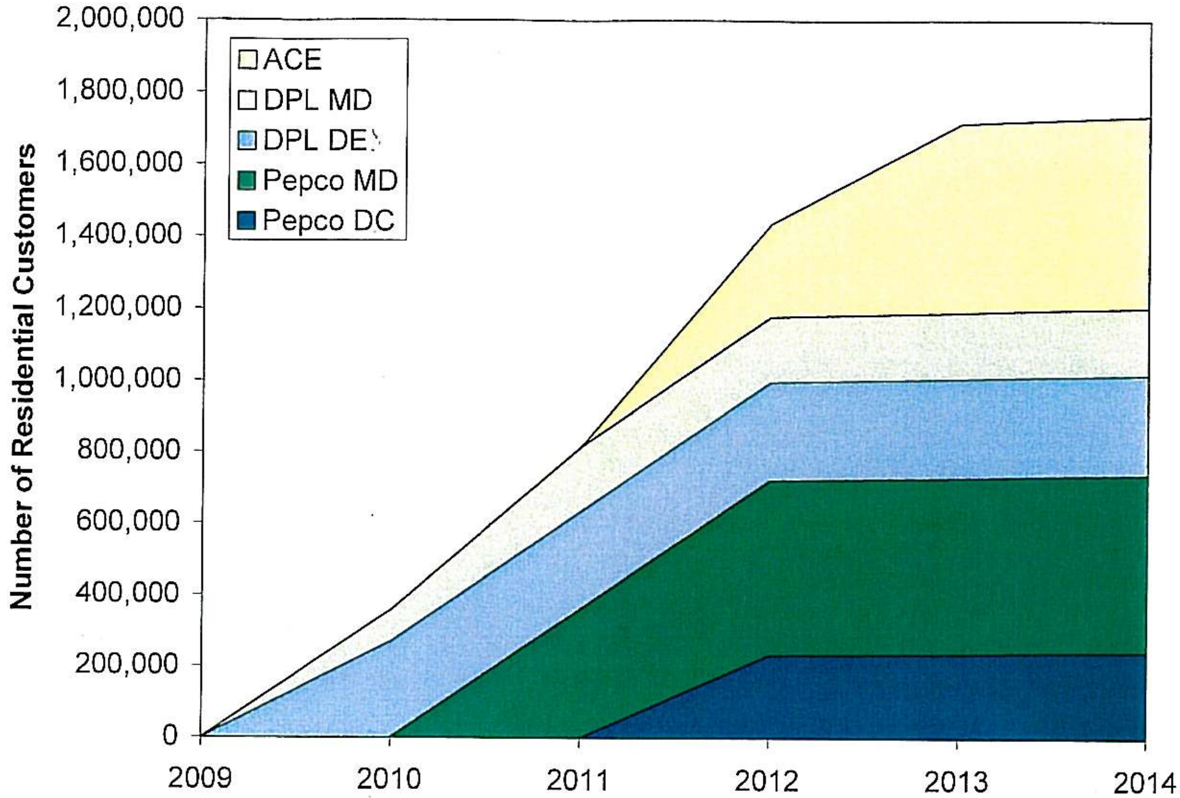
The current plan is to deploy AMI to customers over the period from 2009 to 2013. The deployment schedule varies by jurisdiction. It is assumed that customers are eligible to participate in dynamic pricing once they have been equipped with AMI. In other words, it is not necessary for a jurisdiction to 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)

	Pepco DC	Pepco MD	DPL MD	DPL DE	ACE
2009	0%	0%	25%	50%	0%
2010	0%	38%	75%	100%	0%
2011	50%	88%	100%	100%	25%
2012	100%	100%	100%	100%	75%
2013	100%	100%	100%	100%	100%

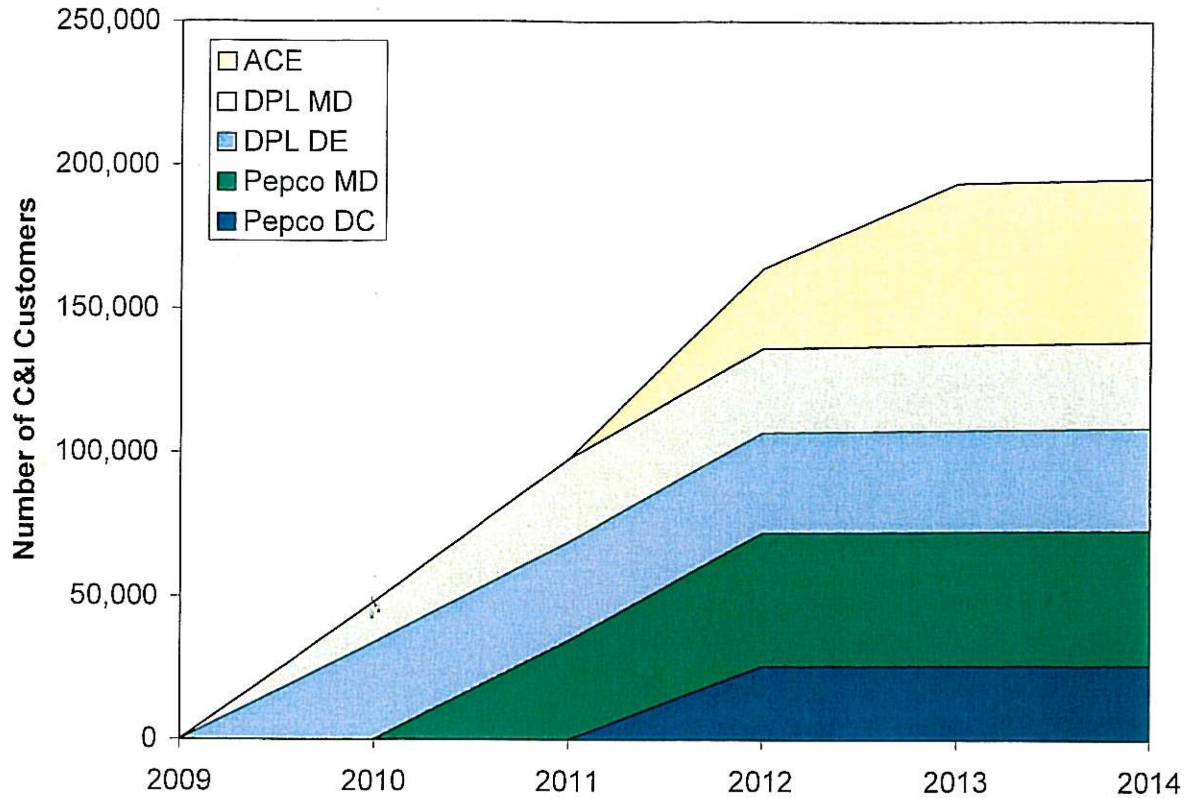
[27] It should be noted that PHI provided an end-of-year AMI deployment schedule, and a mid-year schedule was used in the analysis to approximate the number of customers with AMI during the summer CPP season. Mid-year values were obtained through linear interpolation.

Figure 4.5. Forecast of Residential Customers Equipped with AMI



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.

Figure 4.6. Forecast of C&I Customers Equipped with AMI



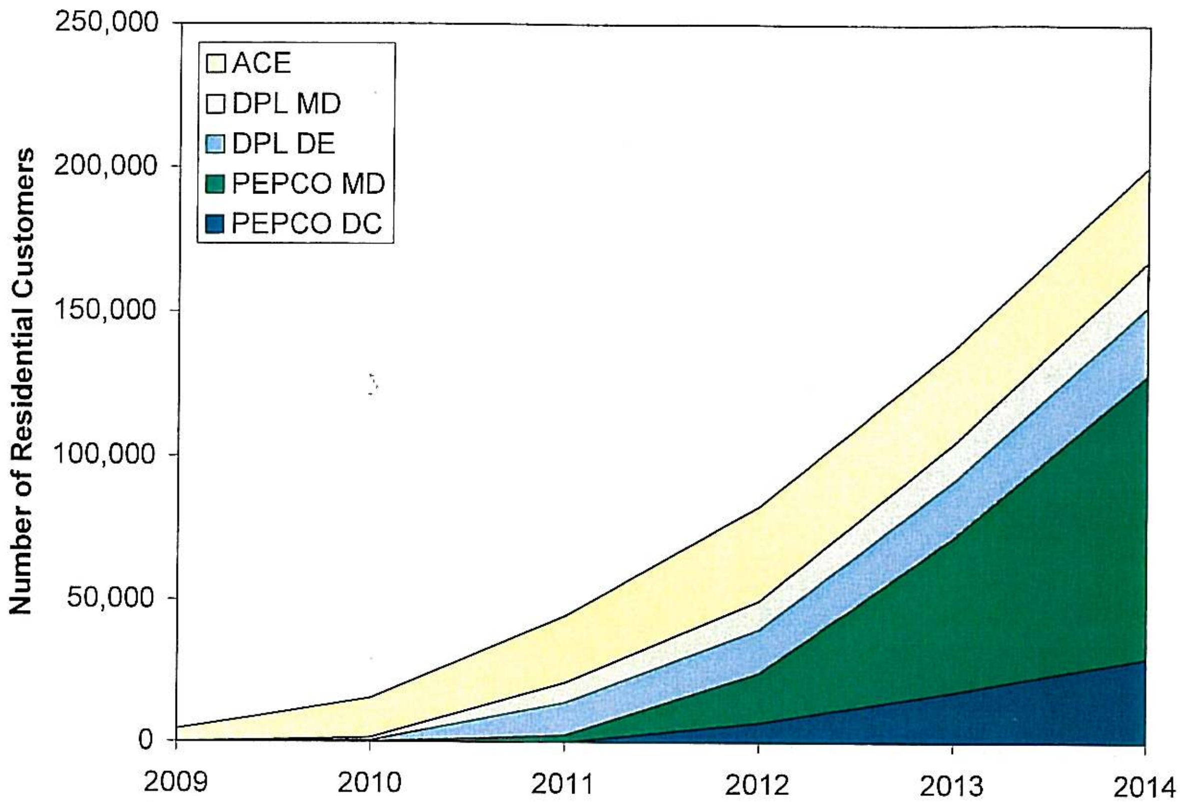
Nearly 200,000 C&I customers will be equipped with AMI in PHI's service territories by the end of 2013. Over 50,000 C&I customers in ACE will be equipped with AMI, representing nearly 30 percent of the total non-interval meter C&I deployment.

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 PHI.[28]

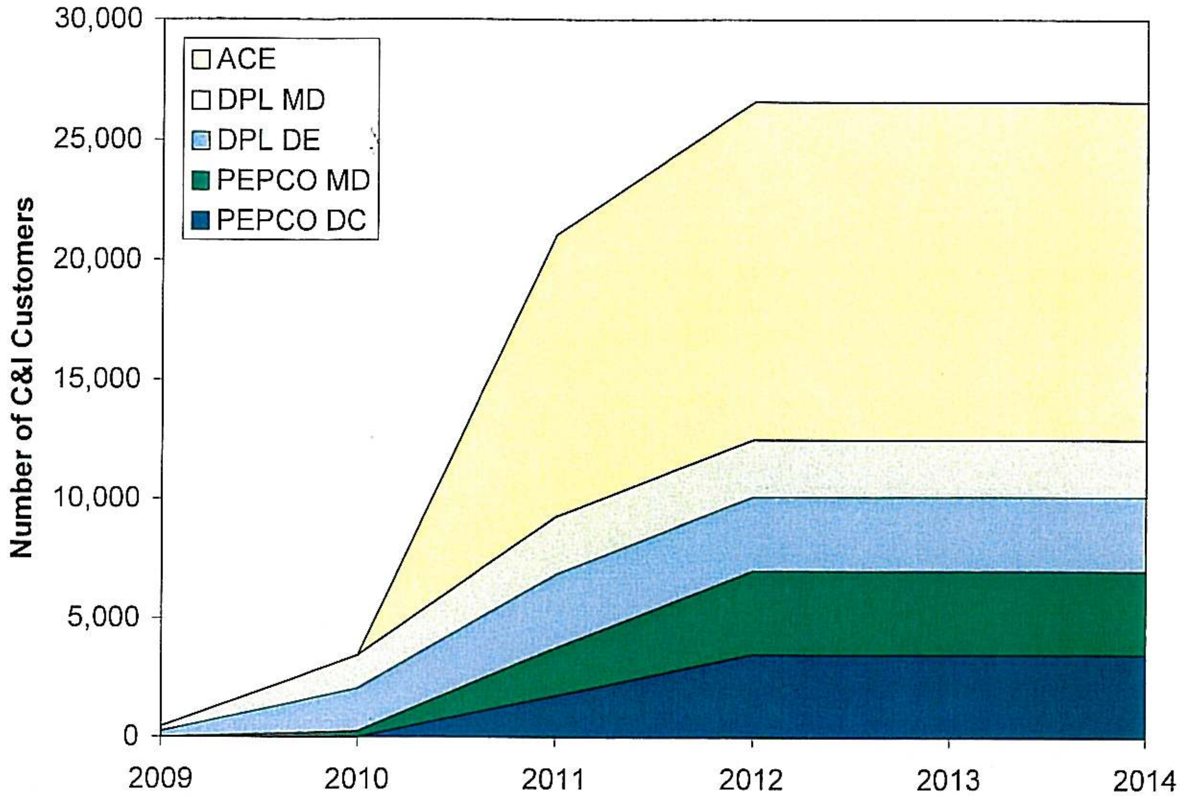
[28] It is assumed that all C&I DLC customers are equipped with AMI rather than interval meters.

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.

Figure 4.8. Forecast of Participation in PHI's Non-residential DLC Program



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.[29] 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.

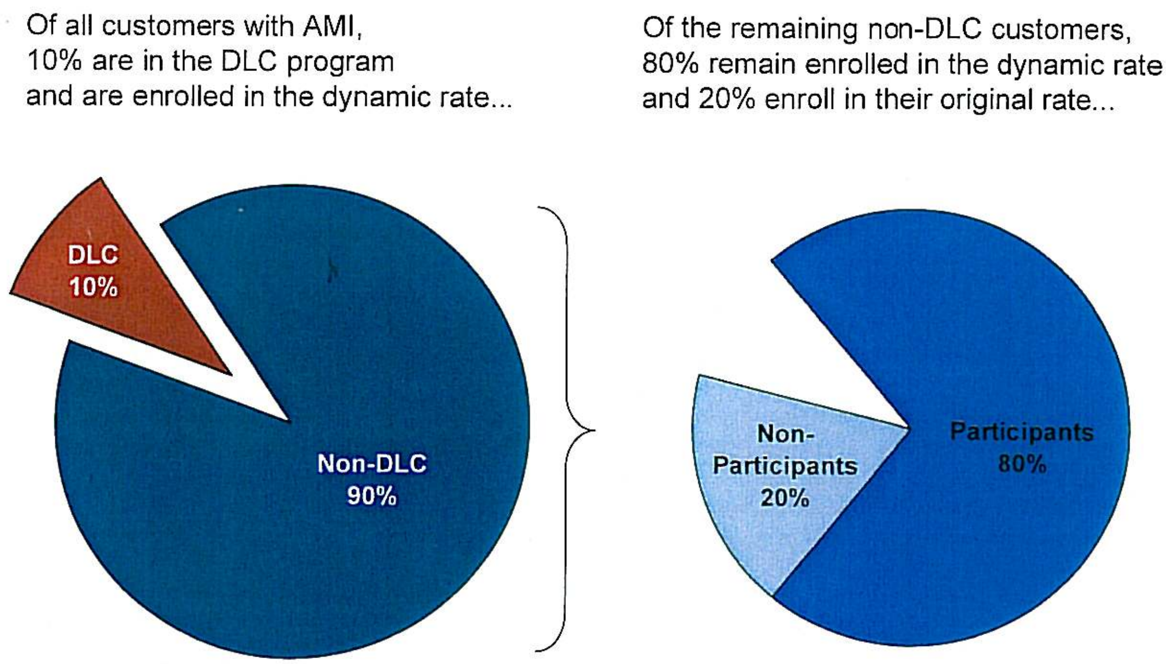
scenarios. Studies have suggested that under the "CPP-Default" scenario, 80 percent of eligible customers could remain on the dynamic tariff. The "CPP-Voluntary" scenario, on the other hand, might lead to only around 20 percent participation in the rate. Due to the wide range of uncertainty surrounding 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.

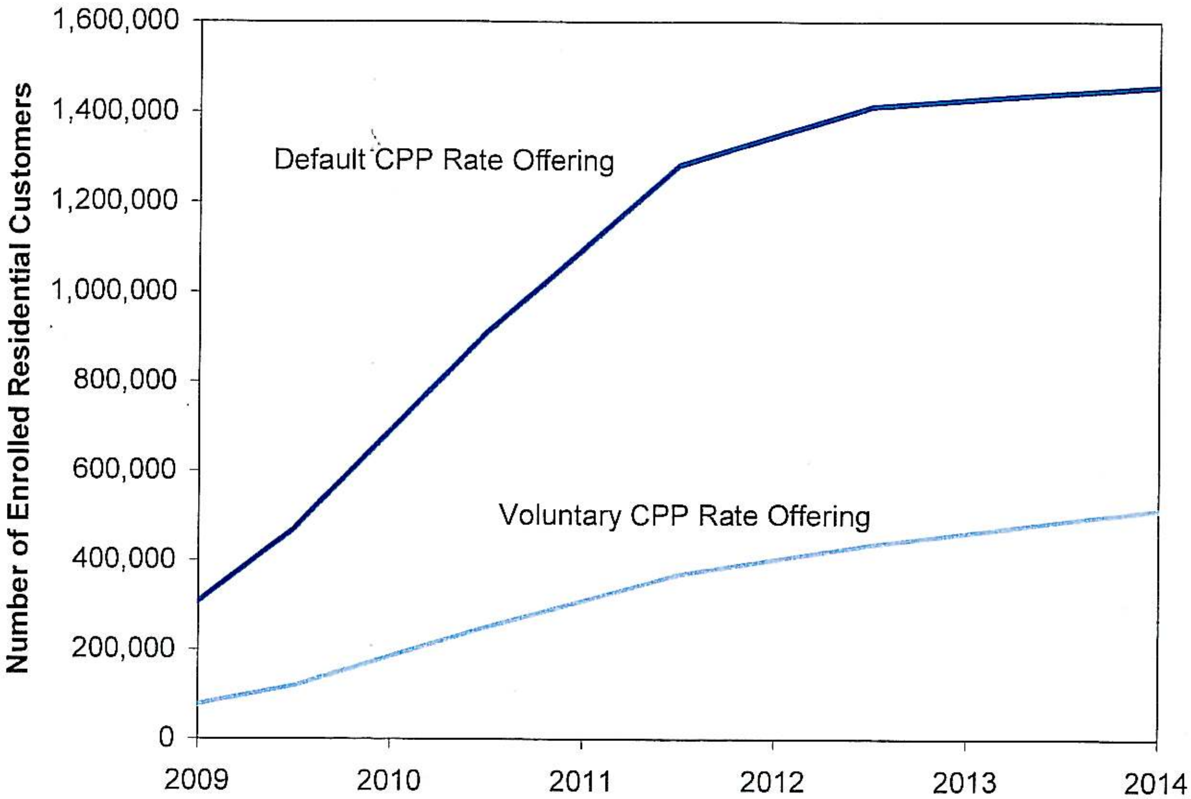
For an illustration of how these factors would determine the number of participating customers, see Figure 4.9. It illustrates the breakout of residential DLC customers, participants, and non-participants under the CPP-Default scenario for Pepco DC in 2013. In this scenario, 82 percent of all residential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

Figure 4.9. Share of Participating Residential Customers in Pepco DC in 2013 (CPP-Default Scenario)



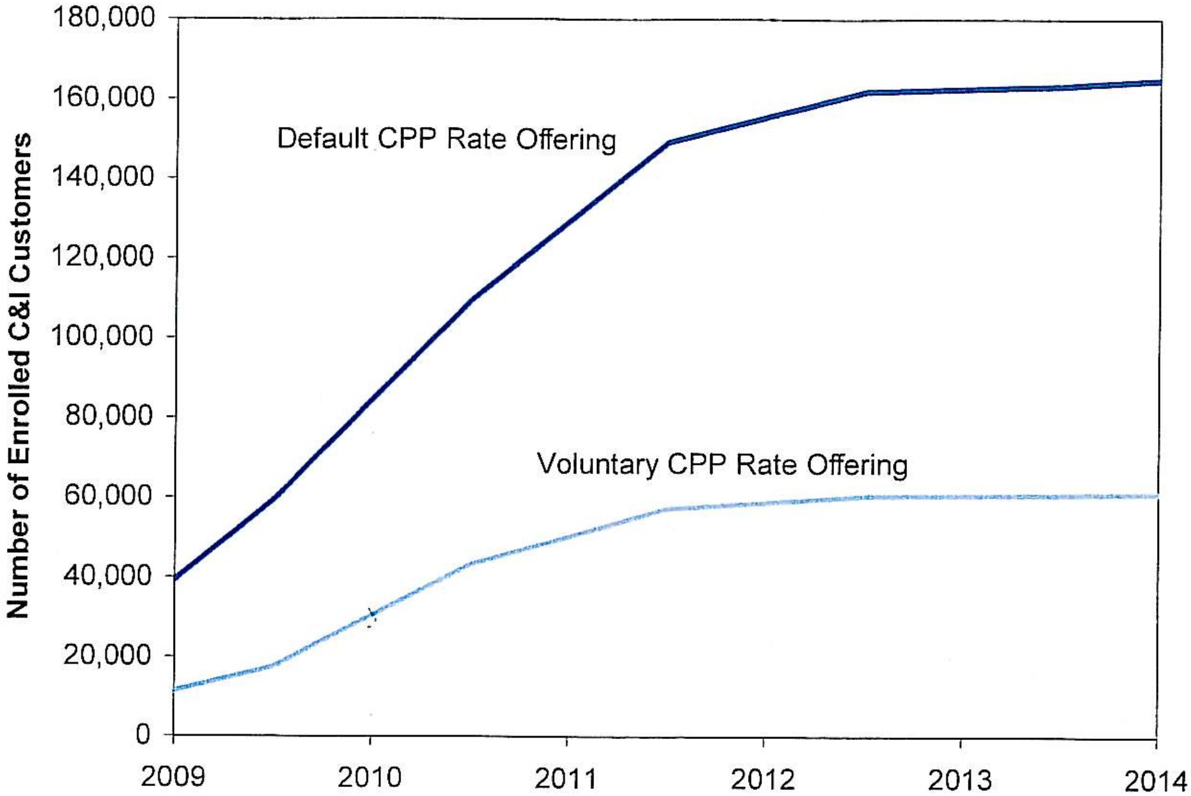
With all of these factors accounted for, the result is a forecast of residential and C&I customers enrolled in the CPP rate in both the CPP-Default scenario and the CPP-Voluntary scenario. These forecasts are summarized in Figure 4.10 and Figure 4.11 below.

Figure 4.10. Forecast of Total Residential CPP Enrollment in All PHI Jurisdictions



Over 1.4 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.

Figure 4.11. Forecast of Total C&I CPP Enrollment in All PHI Jurisdictions

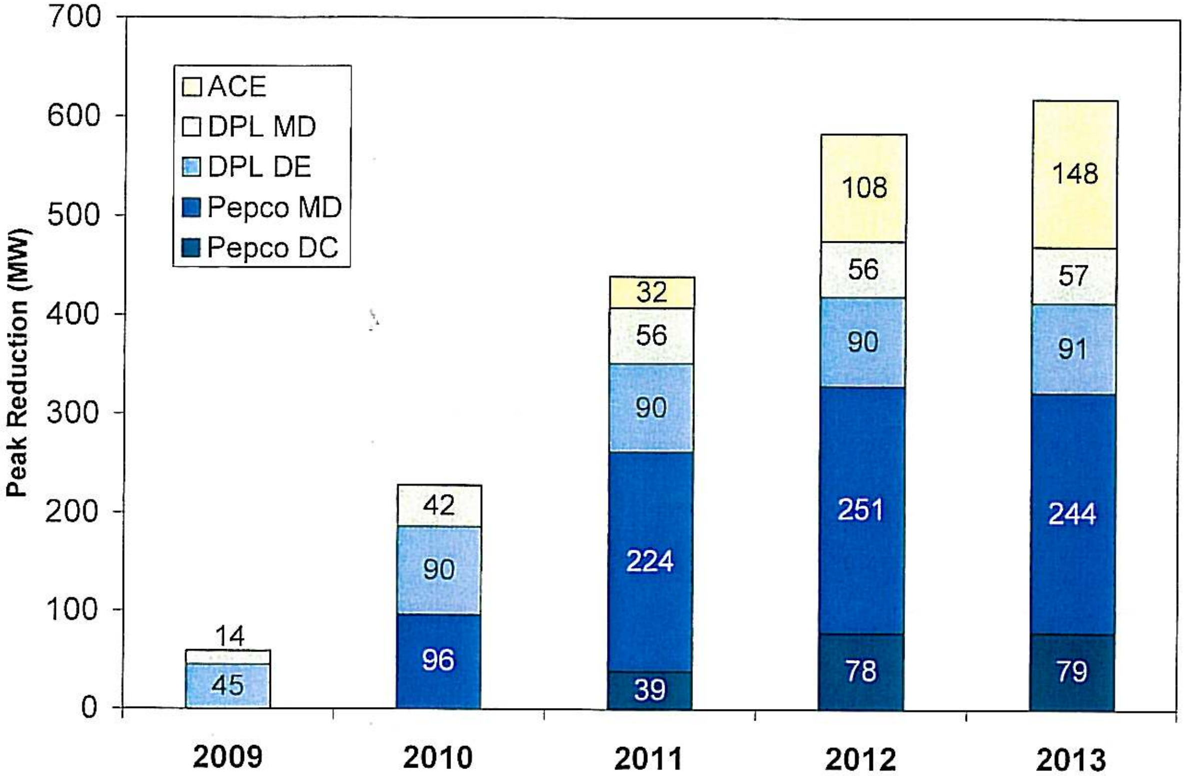


Over 160,000 C&I customers are expected to enroll in the dynamic rate by 2013 if it is offered as the default rate. Approximately 60,000 are anticipated to enroll if it is offered as a voluntary rate.

4.5. SYSTEM-WIDE PEAK DEMAND IMPACTS OF DYNAMIC PRICING

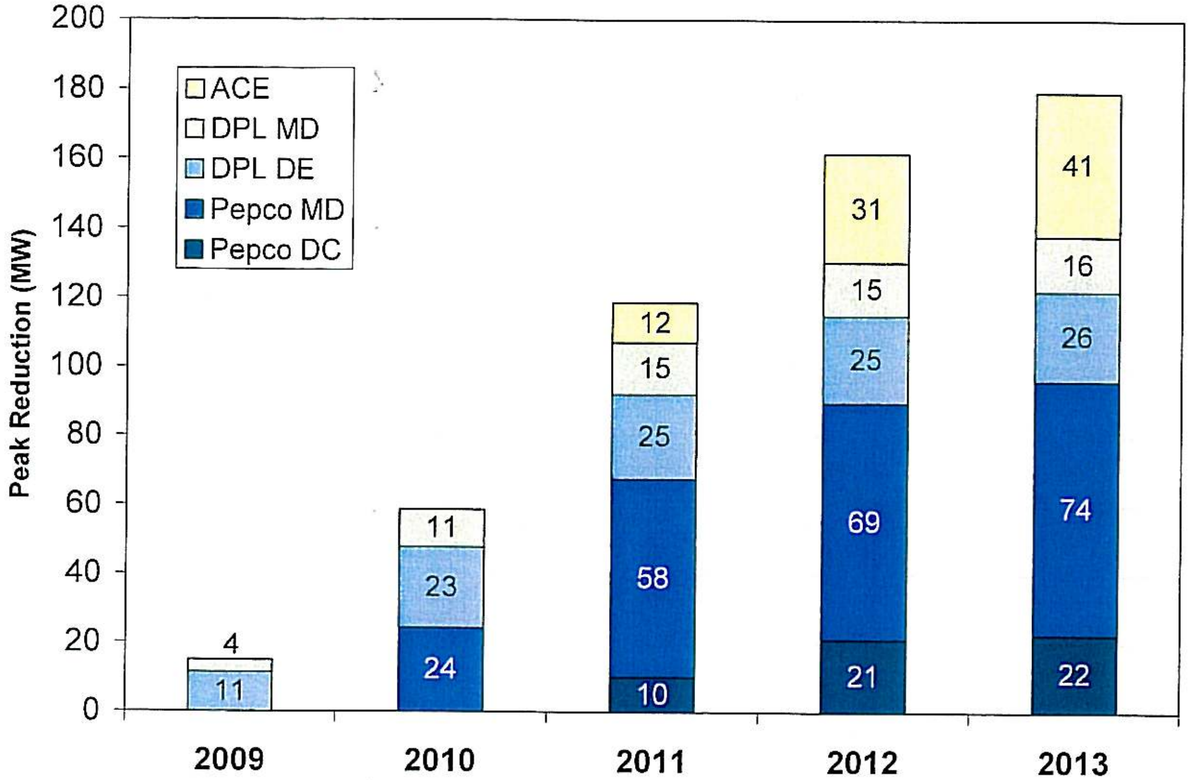
Multiplying the per-customer kilowatthours-per-hour peak reductions by the forecast of participating customers results in an annual forecast of system-wide peak demand reductions for PHI's service territories. These forecasts are summarized in Figure 4.12 for the CPP-Default scenario and Figure 4.13 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.

Figure 4.13. System-Wide Peak Demand Reductions Attributable to Dynamic Pricing
CPP-Voluntary Scenario



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.[30]

[30] 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.[31] 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.[32]

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.

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31 PJM, RPM Planning Period Parameters, http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls

32 See *Rising Utility Construction Costs: Sources and Impacts*, prepared by Prepared by Marc W. Chupka and Gregory Basheda at *The Brattle Group* for The Edison Foundation, September 2007.

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

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	758,523	758,523	758,523	748,357	748,357	748,357
Jurisdictional Reduction (MW)	220	220	220	389	389	389
Reductions Not Offset by Supplier Response	103	220	220	228	389	389
Avoided Capacity Costs (million 2007 $'s)	$11	$11	$16	$20	$20	$28

Table 5.2. Estimated Capacity Savings in 2013

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	737,505	737,505	737,505	711,144	711,144	711,144
Jurisdictional Reduction (MW)	570	570	570	1,009	1,009	1,009
Reductions Not Offset by Supplier Response	101	350	570	119	620	1,009
Avoided Capacity Costs (million 2007 $'s)	$29	$29	$47	$52	$52	$83

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 participate 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

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	758,523	758,523	758,523	748,357	748,357	748,357
Jurisdictional Reduction (MW)	220	220	220	389	389	389
Reductions Not Offset by Supplier Response	103	220	220	228	389	389
Avoided Energy Costs (million 2007 $'s)	$3	$3	$4	$5	$5	$7

Table 5.4. Estimated Generation Savings in 2013

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	737,505	737,505	737,505	711,144	711,144	711,144
Jurisdictional Reduction (MW)	570	570	570	1,009	1,009	1,009
Reductions Not Offset by Supplier Response	101	350	570	119	620	1,009
Avoided Energy Costs (million 2007 $'s)	$7	$7	$11	$12	$12	$20

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 the PJM market does 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 Q_1 to Q_2. This causes the spot price to drop from P_1 to P_2. 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. Conceptual Diagram of Short-Term Energy Spot Price Impacts and Customer Benefits

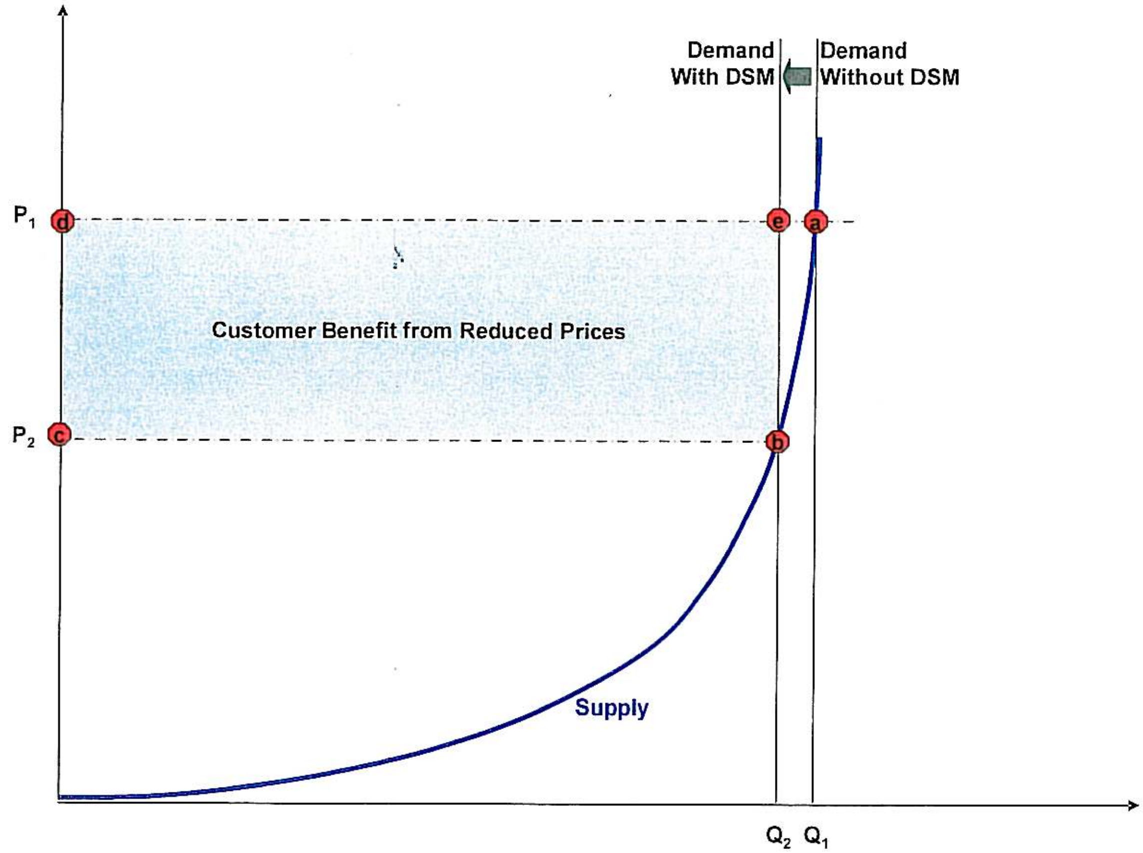


Figure 6.1 represents a short-run equilibrium in which supply remains static in spite of a reduction in demand and prices. In the long-run, the supply side can be expected to adjust to the prospect of depressed returns by accelerating retirements and/or delaying new construction, thus increasing energy 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:

- <u>For DSM implementation by each PHI jurisdiction in isolation, and all PHI jurisdictions in concert</u>: 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.

- <u>For DSM implementation in the entire PJM-East region</u>: 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.[34]

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, $5/6^{th}$ of the load is exposed. These assumptions result in discounted customer benefits relative to the *Brattle*-PJM-MADRI study – a 50 percent

[34] 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

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	758,523	758,523	758,523	748,357	748,357	748,357
Jurisdictional Reduction (MW)	220	220	220	389	389	389
Reductions Not Offset by Supplier Response	103	220	220	228	389	389
Average Price Impact ($/MWh)	$2.3	$4.9	$4.9	$5.8	$9.9	$9.9
Average Price Impact per MW of Load Reduction	$0.01	$0.02	$0.02	$0.01	$0.03	$0.03
Hours affected	60	60	60	60	60	60
Average Residual Load (MW)	12,642	12,642	12,642	12,473	12,473	12,473
Annualized % of Residual Load Exposed to Market	50%	83%	100%	50%	83%	100%
Benefit to Exposed Residual Load (million 2007 $'s)	$1.2	$2.6	$2.6	$3.1	$5.2	$5.2

Table 6.2. Estimated Energy Price Impacts in 2013

	CPP-Voluntary			CPP-Default		
Supply Response Scenario	Immediate	Slower	Delayed	Immediate	Slower	Delayed
Peak Load (MW)	13,480	13,480	13,480	13,480	13,480	13,480
Total Load (MWh)	737,505	737,505	737,505	711,144	711,144	711,144
Jurisdictional Reduction (MW)	570	570	570	1,009	1,009	1,009
Reductions Not Offset by Supplier Response	101	350	570	119	620	1,009
Average Price Impact ($/MWh)	$2.4	$8.2	$13.4	$2.8	$14.6	$23.7
Average Price Impact per MW of Load Reduction	$0.004	$0.014	$0.023	$0.003	$0.014	$0.024
Hours affected	60	60	60	60	60	60
Average Residual Load (MW)	12,292	12,292	12,292	11,852	11,852	11,852
Annualized % of Residual Load Exposed to Market	50%	83%	100%	50%	83%	100%
Benefit to Exposed Residual Load (million 2007 $'s)	$1.4	$4.8	$7.8	$1.5	$8.0	$13.0

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,

[35] This approach is somewhat crude because the price ratios do not capture the differences in price sensitivities to changes in demand in the real-time versus day-ahead markets.

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

		CPP-Voluntary		CPP-Default	
	Locational Delivery Area:	EMAAC	SWMAAC	EMAAC	SWMAAC
Load Reduction Available from DSM	MW	131	80	223	151
Capacity Market Price w/o DSM	$/MW-day	190	237	190	237
Capacity Market Price with DSM	$/MW-day	180	226	175	217
Change in Capacity Price	$/MW-day	-10	-11	-15	-20
Capacity Requirement	MW	39318	17098	39318	17098
Annual Customer Benefit	($ millions)	143	66	213	122

Table 7.2 - Capacity Market Price Impact of DSM in Delivery Year 2013/14
In the "Delayed Supplier Reaction" Scenario

		CPP-Voluntary		CPP-Default	
	Locational Delivery Area:	EMAAC	SWMAAC	EMAAC	SWMAAC
Load Reduction Available from DSM	MW	236	317	437	541
Capacity Market Price w/o DSM	$/MW-day	223	239	223	239
Capacity Market Price with DSM	$/MW-day	223	239	223	239
Change in Capacity Price	$/MW-day	0	0	0	0
Capacity Requirement	MW	41538	17893	41538	17893
Annual Customer Benefit	($ millions)	0	0	0	0

Figure 7.1. Simulated Capacity Auction for EMAAC in 2010
Delayed Supplier Reaction Scenario with CPP as the Default Rate

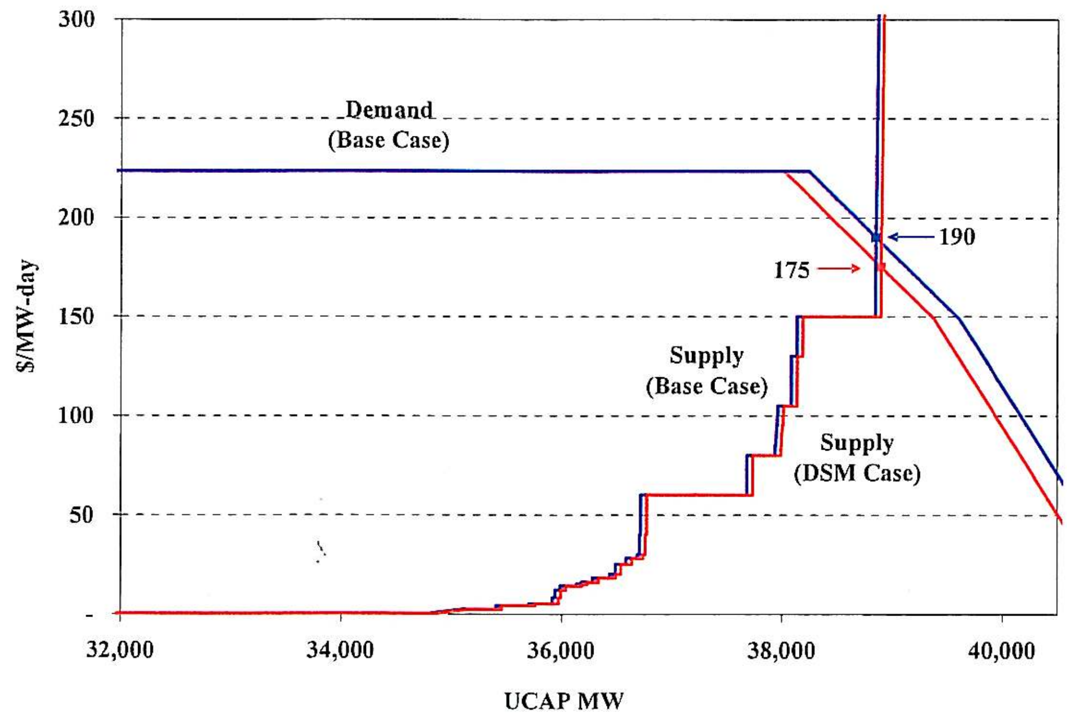


Figure 7.2. Simulated Capacity Auction for EMAAC in 2013
Delayed Supplier Reaction Scenario with CPP as the Default Rate

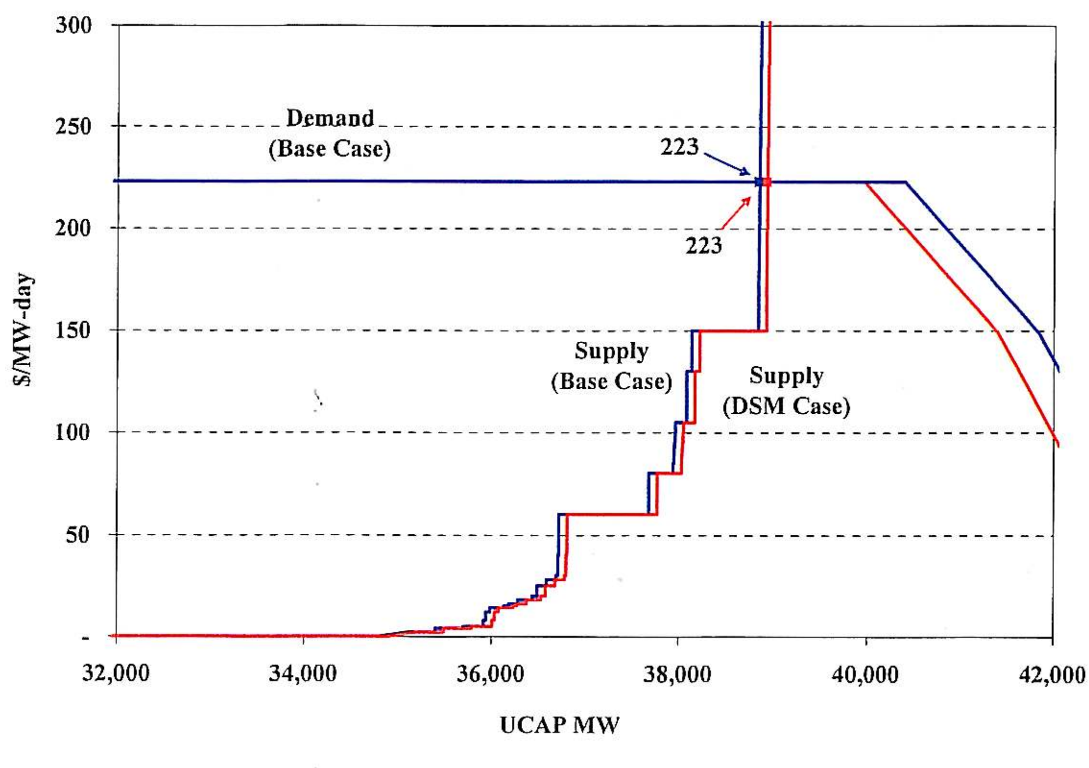


Figure 7.3. Simulated Capacity Auction for SWMAAC in 2010
Delayed Supplier Reaction Scenario with CPP as the Default Rate

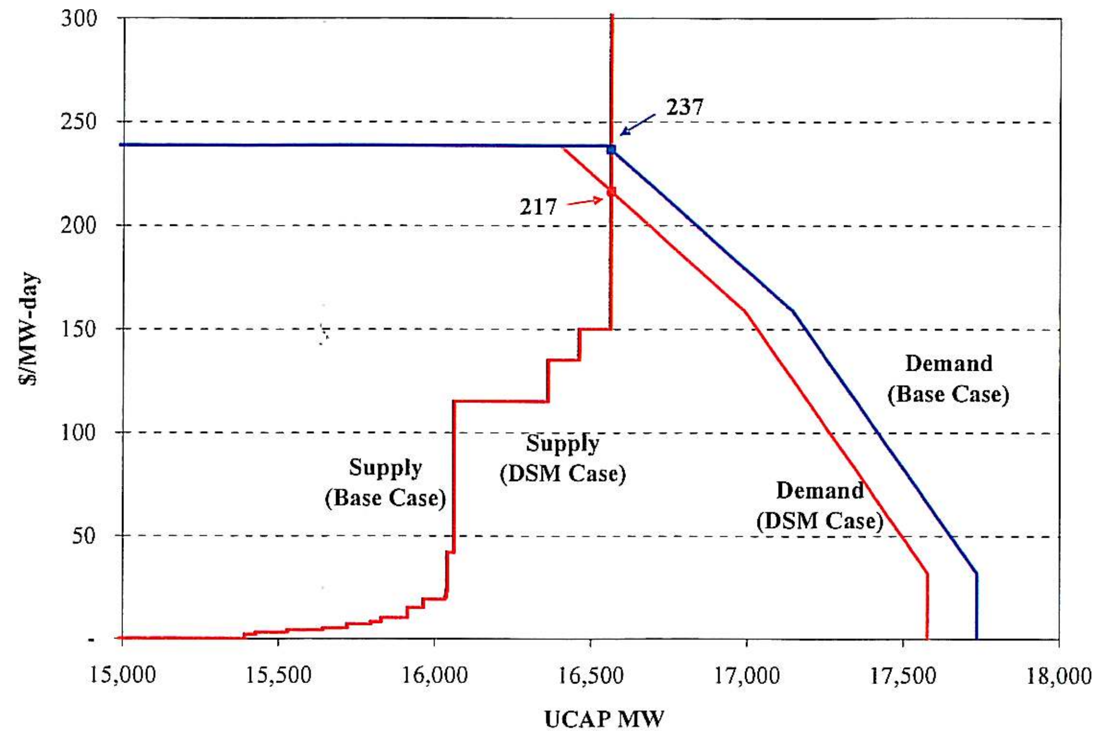
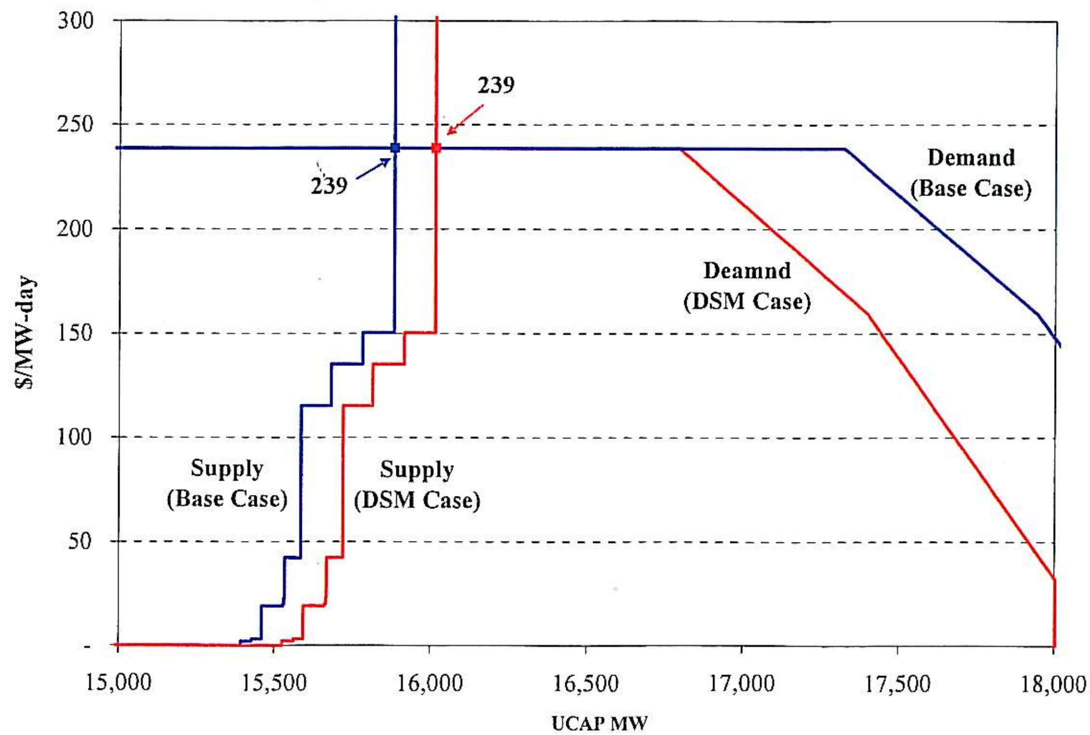


Figure 7.4. Simulated Capacity Auction for SWMAAC in 2013
Delayed Supplier Reaction Scenario with CPP as the Default Rate



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

[36] See *Value of Lost Load*,. Prepared by SAIC for Midwest ISO, May 2006; *Value of a Reliable Supply of Electricity* prepared by ICF for EEI, December 2005; *A Framework and Review of Customer Outage Costs*, prepared by LBL and Population Research Systems for DOE, November 2003; *Value of Service Reliability Study*, Prepared by Hagler Bailly for SCE, September 2000.

Response" scenario. 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		EMAAC LDA	
	2010	**2013**	**2010**	**2013**
Internal Supply (UCAP MW) [1]	16,561	15,983	39,309	39,309
Coincident Peak Load (MW)[2]	14,487	15,161	33,579	35,474
LDA Reliability Requirement[3]	17,098	17,893	39,318	41,538
DR Load Reduction (MW)[4]	151	541	223	437
Pool-wide Avg EFORd[5]	6.13%	6.13%	6.13%	6.13%
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 (%, in UCAP terms)				
Base Case	14.3%	5.4%	17.1%	10.8%
DR Case	15.5%	9.3%	17.8%	12.2%
Projected Reserve Margin (%, in ICAP terms)				
Base Case	**15.2%**	**5.8%**	**18.1%**	**11.5%**
DR Case	**16.5%**	**9.9%**	**18.9%**	**12.9%**

[1] Based on aggregate supply in 2007/2008 Base Residual Auction (BRA). In future years, new capacity under construction construction was added, and units scheduled for retirement removed from supply. No generic capacity additions were assumed.
[2] Source of 2010 peak load: PJM Load Forecast Report, January 2007. Values for 2013 were derived by assuming an annual load growth equal to the growth rate in 2010.
[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 reliabilty 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 nascence 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.

[37] *Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, CAISO, February 24, 2005.

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.[38] 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,

[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 lese the total amount of emissions from all sources will remain unchanged.

can substantially reduce the quantity of generation. The potentially very large value to customers and the potential environmental benefits have not been analyzed in this study.

9.0 NET PRESENT VALUE OF BENEFITS

All of the categories of benefits are calculated on an annual basis, and a net present value is computed using the after-tax weighted average cost of capital provided for the PHI companies. The applicable rates are: ACE NJ 6.69%, Delmarva DE 6.23%, Delmarva DE 7.03%, PEPCO DC 7.09%, PEPCO MD 7.17%. To discount the benefit to all Maryland consumers, a load-weighted average of Delmarva MD and PEPCO MD rates is used (7.1%). To discount the benefit to all New Jersey consumers, the same rate was used as for ACE NJ. To discount the benefit to all consumers in PHI zones, as well as to all consumers in PJM-East, a load-weighted average rate of 6.85% was used.

The net present value of benefits for each scenario and for each combination of implementation area and beneficiary area, as described in Section 3, is tabulated below.

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

DSM Implemented in:	ACE NJ			ACE NJ			DPL DE		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$114	$114	$125	$114	$114	$125	$87	$87	$98
Avoided Energy Costs	$27	$27	$30	$27	$27	$30	$21	$21	$23
Ancillary Services Benefit	$3	$3	$3	$3	$3	$3	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.5	$1.8	$2.5	$3.1	$11.5	$15.9	$1.0	$4.5	$7.8
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$1.4	$2.2	$2.7	$0.6	$1.0	$1.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$17.4	$0.0	$0.0	$125.9	$0.0	$0.0	$18.2
AVERAGE QUANTIFIED BENEFIT **	$145	$146	$178	$147	$156	$300	$112	$116	$151
Low Peak	$131	$132	$162	$133	$138	$280	$102	$104	$136
High Peak	$158	$160	$194	$162	$173	$320	$123	$128	$166

* 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.

DSM Implemented in:	DPL MD			DPL MD			PEPCO DC		
Benefits to Customers in:	DPL MD			All MD			PEPCO DC		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$47	$47	$53	$47	$47	$53	$92	$92	$103
Avoided Energy Costs	$11	$11	$13	$11	$11	$13	$22	$22	$25
Ancillary Services Benefit	$1	$1	$1	$1	$1	$1	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.3	$1.2	$1.8	$0.7	$3.2	$4.9	$0.5	$2.1	$2.8
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$0.5	$0.9	$1.1	$0.2	$0.3	$0.4
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$3.7	$0.0	$0.0	$26.0	$0.0	$0.0	$15.6
AVERAGE QUANTIFIED BENEFIT **	$60	$61	$73	$60	$62	$98	$117	$118	$149
Low Peak	$54	$55	$66	$54	$56	$90	$106	$107	$136
High Peak	$65	$67	$80	$66	$69	$106	$128	$130	$162

EXHIBIT C

DSM Implemented in:	PEPCO MD			PEPCO MD			All PHI		
Benefits to Customers in:	PEPCO MD			All MD			PHI		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$204	$204	$231	$206	$206	$233	$548	$548	$614
Avoided Energy Costs	$49	$49	$55	$49	$49	$56	$131	$131	$147
Ancillary Services Benefit	$5	$5	$5	$5	$5	$5	$16	$16	$16
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$2.9	$12.2	$16.6	$6.4	$27.1	$36.7	$5.4	$22.0	$31.7
Potential Additional Real-Time Benefit	$2.3	$3.8	$4.6	$5.0	$8.4	$10.0	$3.5	$5.8	$7.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$89.9	$0.0	$0.0	$90.2	$0.0	$0.0	$275.4
AVERAGE QUANTIFIED BENEFIT **	$261	$271	$398	$267	$288	$421	$700	$717	$1,084
Low Peak	$237	$243	$365	$241	$255	$381	$634	$644	$1,000
High Peak	$286	$299	$431	$293	$321	$461	$766	$789	$1,168

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$117	$117	$125	$117	$117	$125	$80	$80	$98
Avoided Energy Costs	$28	$28	$30	$28	$28	$30	$19	$19	$23
Ancillary Services Benefit	$3	$3	$3	$23	$23	$23	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$10.4	$41.4	$58.8	$58.9	$236.0	$335.1	$5.8	$22.2	$31.0
Potential Additional Real-Time Benefit	$3.9	$6.6	$7.9	$30.7	$51.4	$62.0	$2.5	$4.3	$5.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$238.0	$0.0	$0.0	$1,723.7	$0.0	$0.0	$244.3
AVERAGE QUANTIFIED BENEFIT **	$158	$190	$455	$227	$404	$2,237	$108	$124	$400
Low Peak	$140	$157	$413	$192	$303	$2,098	$96	$105	$375
High Peak	$177	$222	$497	$263	$505	$2,376	$120	$144	$425

EXHIBIT C

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	PEPCO DC			DPL MD			PEPCO MD		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$93	$93	$103	$44	$44	$53	$205	$205	$231
Avoided Energy Costs	$22	$22	$25	$11	$11	$13	$49	$49	$55
Ancillary Services Benefit	$2	$2	$2	$1	$1	$1	$5	$5	$5
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$5.4	$21.6	$30.7	$2.4	$9.4	$13.1	$13.5	$54.1	$76.8
Potential Additional Real-Time Benefit	$3.8	$6.4	$7.7	$1.1	$1.8	$2.2	$9.6	$16.0	$19.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$122.1	$0.0	$0.0	$95.1	$0.0	$0.0	$281.7
AVERAGE QUANTIFIED BENEFIT **	$123	$140	$283	$59	$66	$175	$273	$313	$650
Low Peak	$111	$121	$260	$52	$56	$163	$244	$270	$596
High Peak	$136	$158	$306	$65	$75	$187	$301	$357	$705

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	All MD			PHI			PJM East		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$250	$250	$286	$543	$543	$614	$2,838	$2,838	$3,054
Avoided Energy Costs	$60	$60	$68	$130	$130	$147	$680	$680	$732
Ancillary Services Benefit	$16	$16	$16	$16	$16	$16	$78	$78	$78
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$41.6	$165.8	$234.8	$37.1	$147.4	$208.5	$179.3	$715.7	$1,014.5
Potential Additional Real-Time Benefit	$27.8	$46.6	$56.3	$21.2	$35.4	$42.8	$93.3	$156.2	$188.6
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$951.5	$0.0	$0.0	$990.7	$0.0	$0.0	$3,604.8
AVERAGE QUANTIFIED BENEFIT **	$368	$493	$1,557	$725	$836	$1,976	$3,776	$4,313	$8,484
Low Peak	$325	$408	$1,445	$647	$713	$1,820	$3,381	$3,724	$7,763
High Peak	$412	$577	$1,669	$804	$958	$2,132	$4,171	$4,901	$9,206

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

DSM Implemented in:	ACE NJ			ACE NJ			DPL DE		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$62	$62	$69	$62	$62	$69	$47	$47	$53
Avoided Energy Costs	$15	$15	$17	$15	$15	$17	$11	$11	$13
Avoided Ancillary Services Costs	$3	$3	$3	$3	$3	$3	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.3	$1.1	$1.7	$1.7	$7.2	$10.9	$0.6	$2.5	$4.2
Potential Additional Real-Time Benefit	$0.1	$0.2	$0.2	$0.8	$1.3	$1.6	$0.3	$0.4	$0.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$14.2	$0.0	$0.0	$102.9	$0.0	$0.0	$9.9
AVERAGE QUANTIFIED BENEFIT **	$81	$82	$105	$82	$88	$203	$63	$65	$84
Low Peak	$74	$74	$97	$75	$78	$191	$57	$58	$76
High Peak	$88	$90	$114	$90	$98	$215	$69	$72	$92

* Supplier Reaction Scenario; Immediate: short-term price impacts last for 1 year; Slower response: short-term price impacts last for 3 years, Delayed response: there is no generic entry, and short-term price impacts last through 2013.

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

DSM Implemented in:	DPL MD			DPL MD			PEPCO DC		
Benefits to Customers in:	DPL MD			All MD			PEPCO DC		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$25	$25	$28	$25	$25	$28	$62	$62	$70
Avoided Energy Costs	$6	$6	$7	$6	$6	$7	$15	$15	$17
Avoided Ancillary Services Costs	$1	$1	$1	$1	$1	$1	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.1	$0.6	$1.0	$0.4	$1.7	$2.7	$0.4	$1.4	$2.0
Potential Additional Real-Time Benefit	$0.1	$0.1	$0.1	$0.2	$0.4	$0.5	$0.1	$0.1	$0.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$2.1	$0.0	$0.0	$14.9	$0.0	$0.0	$12.2
AVERAGE QUANTIFIED BENEFIT **	$33	$33	$40	$33	$34	$54	$80	$81	$104
Low Peak	$30	$30	$36	$30	$31	$50	$72	$73	$95
High Peak	$36	$37	$43	$36	$38	$58	$87	$89	$112

DSM Implemented in:	PEPCO MD			PEPCO MD			All PHI		
Benefits to Customers in:	PEPCO MD			All MD			PHI		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$109	$109	$121	$109	$109	$122	$309	$309	$345
Avoided Energy Costs	$26	$26	$29	$26	$26	$29	$74	$74	$83
Avoided Ancillary Services Costs	$5	$5	$5	$5	$5	$5	$16	$16	$16
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$1.7	$6.1	$8.3	$3.6	$13.4	$18.2	$2.9	$11.6	$17.3
Potential Additional Real-Time Benefit	$0.9	$1.6	$1.9	$2.0	$3.4	$4.1	$1.5	$2.5	$3.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$39.7	$0.0	$0.0	$39.9	$0.0	$0.0	$162.8
AVERAGE QUANTIFIED BENEFIT **	$141	$146	$203	$144	$154	$214	$401	$410	$623
Low Peak	$128	$131	$186	$130	$137	$194	$364	$369	$576
High Peak	$155	$161	$220	$158	$171	$235	$438	$451	$670

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$61	$61	$69	$61	$61	$69	$45	$45	$53
Avoided Energy Costs	$15	$15	$17	$15	$15	$17	$11	$11	$13
Avoided Ancillary Services Costs	$3	$3	$3	$24	$24	$24	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$6.0	$24.0	$35.3	$34.9	$138.9	$204.4	$3.1	$12.2	$17.7
Potential Additional Real-Time Benefit	$2.0	$3.3	$4.0	$15.5	$25.9	$31.3	$1.2	$2.0	$2.4
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$144.8	$0.0	$0.0	$1,048.8	$0.0	$0.0	$148.2
AVERAGE QUANTIFIED BENEFIT **	$85	$103	$270	$134	$238	$1,363	$62	$71	$235
Low Peak	$75	$85	$245	$114	$180	$1,279	$56	$61	$221
High Peak	$95	$121	$294	$154	$297	$1,447	$69	$82	$250

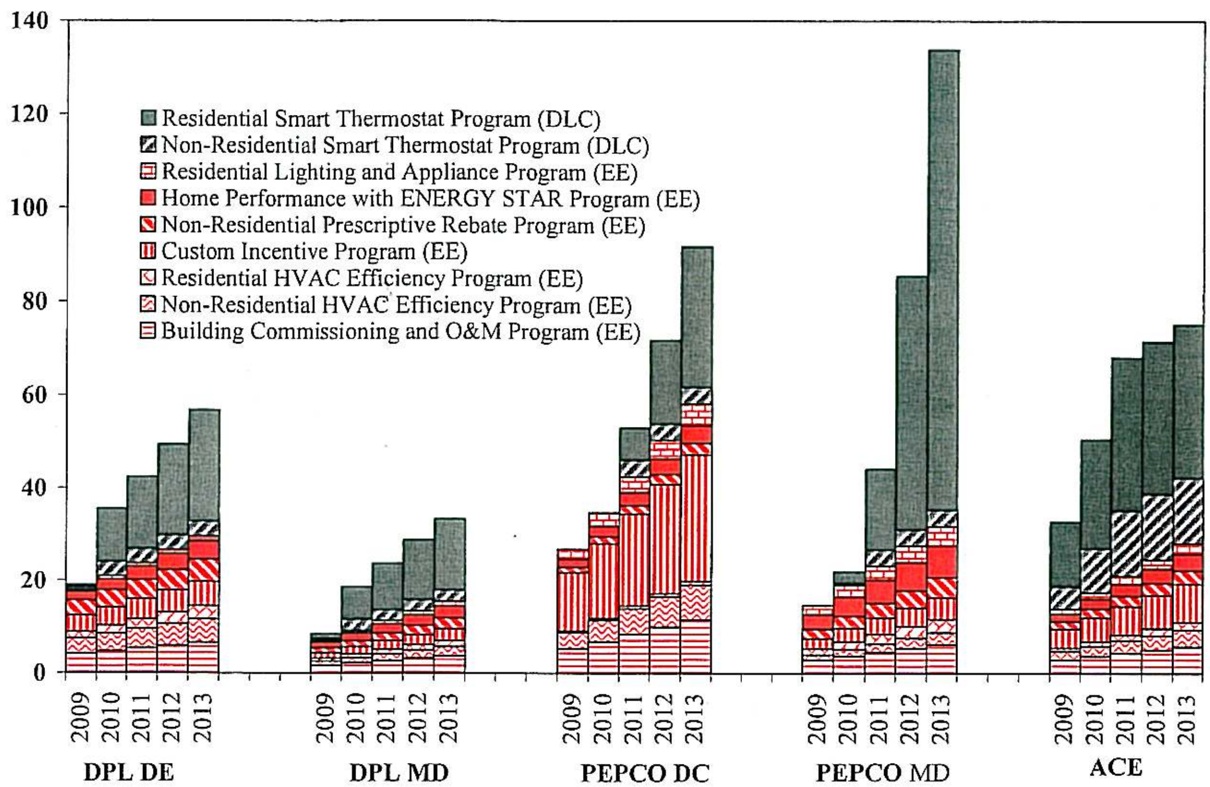
DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	PEPCO DC			DPL MD			PEPCO MD		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$63	$63	$70	$24	$24	$28	$113	$113	$121
Avoided Energy Costs	$15	$15	$17	$6	$6	$7	$27	$27	$29
Avoided Ancillary Services Costs	$2	$2	$2	$1	$1	$1	$5	$5	$5
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$3.1	$12.7	$18.7	$1.3	$5.2	$7.5	$7.9	$31.7	$46.9
Potential Additional Real-Time Benefit	$1.9	$3.2	$3.9	$0.5	$0.8	$1.0	$4.8	$8.1	$9.7
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$57.7	$0.0	$0.0	$58.0	$0.0	$0.0	$133.2
AVERAGE QUANTIFIED BENEFIT **	$83	$93	$166	$33	$37	$102	$154	$177	$336
Low Peak	$75	$81	$151	$29	$32	$95	$138	$153	$304
High Peak	$92	$105	$181	$36	$42	$109	$170	$202	$367

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	All MD			PHI			PJM East		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$138	$138	$150	$309	$309	$345	$1,578	$1,578	$1,697
Avoided Energy Costs	$33	$33	$36	$74	$74	$83	$378	$378	$407
Avoided Ancillary Services Costs	$16	$16	$16	$16	$16	$16	$79	$79	$79
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$24.2	$96.5	$142.2	$21.3	$84.9	$124.9	$104.3	$415.5	$611.7
Potential Additional Real-Time Benefit	$13.9	$23.2	$28.1	$10.5	$17.6	$21.3	$46.7	$78.0	$94.4
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$541.8	$0.0	$0.0	$547.7	$0.0	$0.0	$2,081.9
AVERAGE QUANTIFIED BENEFIT **	$212	$285	$887	$420	$484	$1,116	$2,139	$2,450	$4,876
Low Peak	$188	$236	$821	$376	$414	$1,025	$1,917	$2,116	$4,458
High Peak	$236	$333	$952	$465	$554	$1,206	$2,360	$2,784	$5,294

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.)

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



Tables A.1 and A.2 provide the net present value of each of PHI's proposed programs through 2024 and excluding the load reductions from energy efficiency to correlate with the Company's AMI business case. These tables are 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 corresponds to the scenarios in which dynamic pricing is the default rate structure, while Table A.2 corresponds to the scenarios in which enrollment in dynamic pricing is voluntary.

The benefits from AMI-enabled direct load control and dynamic pricing in Delmarva, DE shown in Tables A.1 and A.2 differ slightly from the preliminary estimates presented to the Delaware Public Service Commission on September 5, 2007 because of three revisions to the analysis. First, the "Delayed Supplier Reaction" scenario was modified to reflect construction of adequate supply and return to long-run equilibrium by 2014 instead of 2016, causing short-term market price impacts to last only through 2013 instead of 2015. Second, as described in Section 5.1.2, the capacity prices used to value avoided capacity costs in the "Delayed Supplier Reaction" scenario were projected based on supply conditions consistent with the scenario definition, instead of assuming capacity prices would be determined the net cost of new entry (Net CONE). Net CONE is assumed to set capacity prices only once the market is assumed to reach equilibrium. Third, in all scenarios, estimates of ancillary services benefits were replaced by a point estimate instead of a range.

Table A.1. NPV of Benefits to Customers through 2024 *CPP Default Scenario* (million 2007 $'s)

DSM Implemented in:	ACE NJ			ACE NJ			DPL DE		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$79	$79	$88	$79	$79	$88	$57	$57	$66
Avoided Energy Costs	$19	$19	$21	$19	$19	$21	$14	$14	$16
Ancillary Services Benefit	$2	$2	$2	$2	$2	$2	$3	$3	$3
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.4	$1.5	$2.0	$2.7	$9.7	$13.0	$0.8	$3.7	$6.2
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$1.4	$2.2	$2.7	$0.6	$1.0	$1.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$12.9	$0.0	$0.0	$93.3	$0.0	$0.0	$14.6
AVERAGE QUANTIFIED BENEFIT **	$100	$101	$126	$102	$109	$218	$74	$77	$105
Low Peak	$91.0	$91	$115	$92	$97	$203	$67	$68	$94
High Peak	$110	$111	$138	$113	$122	$233	$81	$85	$115

* 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.

DSM Implemented in:	DPL MD			DPL MD			PEPCO DC		
Benefits to Customers in:	DPL MD			All MD			PEPCO DC		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$32	$32	$37	$32	$32	$37	$47	$47	$53
Avoided Energy Costs	$8	$8	$9	$8	$8	$9	$11	$11	$13
Ancillary Services Benefit	$1	$1	$1	$1	$1	$1	$1	$1	$1
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.2	$1.0	$1.5	$0.6	$2.7	$4.1	$0.3	$1.3	$1.5
Potential Additional Real-Time Benefit	$0.2	$0.3	$0.3	$0.5	$0.9	$1.1	$0.2	$0.3	$0.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$3.1	$0.0	$0.0	$21.5	$0.0	$0.0	$0.0
AVERAGE QUANTIFIED BENEFIT **	$41	$42	$52	$41	$43	$72	$60	$61	$69
Low Peak	$37	$38	$47	$37	$39	$66	$54	$55	$62
High Peak	$45	$46	$57	$45	$48	$78	$65	$67	$75

DSM Implemented in:	PEPCO MD			PEPCO MD			All PHI		
Benefits to Customers in:	PEPCO MD			All MD			PHI		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$152	$152	$176	$153	$153	$177	$369	$369	$423
Avoided Energy Costs	$36	$36	$42	$37	$37	$42	$89	$89	$101
Ancillary Services Benefit	$4	$4	$4	$4	$4	$4	$11	$11	$11
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$2.6	$11.2	$14.8	$5.8	$24.7	$32.8	$4.5	$18.2	$25.4
Potential Additional Real-Time Benefit	$2.3	$3.8	$4.6	$5.0	$8.4	$10.0	$3.5	$5.8	$7.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$77.2	$0.0	$0.0	$77.4	$0.0	$0.0	$208.3
AVERAGE QUANTIFIED BENEFIT **	$195	$203	$314	$199	$218	$334	$473	$487	$769
Low Peak	$176	$182	$288	$180	$192	$302	$428	$436	$709
High Peak	$213	$225	$340	$219	$244	$365	$518	$537	$828

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$80	$80	$87	$80	$80	$87	$54	$54	$68
Avoided Energy Costs	$19	$19	$21	$19	$19	$21	$13	$13	$16
Ancillary Services Benefit	$2	$2	$2	$16	$16	$16	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$8.8	$34.8	$47.9	$50.1	$198.5	$272.9	$4.9	$18.5	$25.1
Potential Additional Real-Time Benefit	$3.9	$6.6	$7.9	$30.7	$51.4	$62.0	$2.5	$4.3	$5.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$191.3	$0.0	$0.0	$1,385.3	$0.0	$0.0	$196.5
AVERAGE QUANTIFIED BENEFIT **	$110	$136	$349	$165	$314	$1,782	$74	$88	$308
Low Peak	$97	$111	$317	$137	$231	$1,671	$66	$73	$289
High Peak	$124	$162	$381	$193	$396	$1,893	$83	$102	$327

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	PEPCO DC			DPL MD			PEPCO MD		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$64	$64	$73	$30	$30	$37	$141	$141	$164
Avoided Energy Costs	$15	$15	$17	$7	$7	$9	$34	$34	$39
Ancillary Services Benefit	$2	$2	$2	$1	$1	$1	$4	$4	$4
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$4.6	$18.2	$25.0	$2.1	$7.8	$10.6	$11.5	$45.5	$62.6
Potential Additional Real-Time Benefit	$3.8	$6.4	$7.7	$1.1	$1.8	$2.2	$9.6	$16.0	$19.3
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$93.5	$0.0	$0.0	$76.4	$0.0	$0.0	$215.8
AVERAGE QUANTIFIED BENEFIT **	$86	$99	$210	$41	$46	$134	$190	$224	$485
Low Peak	$77	$85	$193	$36	$39	$125	$170	$192	$444
High Peak	$95	$114	$227	$45	$53	$143	$211	$257	$527

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	All MD			PHI			PJM East		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$173	$173	$202	$373	$373	$431	$1,949	$1,949	$2,127
Avoided Energy Costs	$41	$41	$48	$89	$89	$103	$467	$467	$510
Ancillary Services Benefit	$11	$11	$11	$11	$11	$11	$53	$53	$53
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$35.3	$139.2	$191.1	$31.5	$123.7	$169.5	$152.2	$601.4	$825.9
Potential Additional Real-Time Benefit	$27.8	$46.6	$56.3	$21.2	$35.4	$42.8	$93.3	$156.2	$188.6
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$753.9	$0.0	$0.0	$780.9	$0.0	$0.0	$2,865.8
AVERAGE QUANTIFIED BENEFIT **	$261	$364	$1,207	$504	$596	$1,495	$2,621	$3,070	$6,382
Low Peak	$229	$298	$1,119	$448	$503	$1,377	$2,339	$2,627	$5,836
High Peak	$293	$431	$1,294	$560	$690	$1,614	$2,903	$3,514	$6,927

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

DSM Implemented in:	ACE NJ			ACE NJ			DPL DE		
Benefits to Customers in:	ACE NJ			All NJ			DPL DE		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$38	$38	$43	$38	$38	$43	$25	$25	$28
Avoided Energy Costs	$9	$9	$10	$9	$9	$10	$6	$6	$7
Avoided Ancillary Services Costs	$2	$2	$2	$2	$2	$2	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.2	$0.8	$1.2	$1.3	$5.4	$7.8	$0.4	$1.6	$2.6
Potential Additional Real-Time Benefit	$0.1	$0.2	$0.2	$0.8	$1.3	$1.6	$0.3	$0.4	$0.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$9.7	$0.0	$0.0	$70.3	$0.0	$0.0	$5.9
AVERAGE QUANTIFIED BENEFIT **	$49	$50	$67	$50	$54	$134	$33	$34	$45
Low Peak	$45	$45	$61	$46	$48	$126	$30	$30	$41
High Peak	$54	$55	$72	$55	$61	$142	$36	$38	$50

* 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.

DSM Implemented in:	DPL MD			DPL MD			PEPCO DC		
Benefits to Customers in:	DPL MD			All MD			PEPCO DC		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$14	$14	$16	$14	$14	$16	$23	$23	$26
Avoided Energy Costs	$3	$3	$4	$3	$3	$4	$6	$6	$6
Avoided Ancillary Services Costs	$1	$1	$1	$1	$1	$1	$1	$1	$1
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$0.1	$0.4	$0.7	$0.3	$1.2	$1.8	$0.2	$0.6	$0.7
Potential Additional Real-Time Benefit	$0.1	$0.1	$0.1	$0.2	$0.4	$0.5	$0.1	$0.1	$0.2
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$1.4	$0.0	$0.0	$9.7	$0.0	$0.0	$0.0
AVERAGE QUANTIFIED BENEFIT **	$18	$19	$23	$19	$19	$32	$29	$30	$34
Low Peak	$17	$17	$21	$17	$17	$30	$27	$27	$30
High Peak	$20	$21	$25	$20	$22	$35	$32	$33	$37

EXHIBIT C

DSM Implemented in:		PEPCO MD			PEPCO MD			All PHI	
Benefits to Customers in:		PEPCO MD			All MD			PHI	
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$73	$73	$83	$73	$73	$83	$174	$174	$198
Avoided Energy Costs	$17	$17	$20	$18	$18	$20	$42	$42	$47
Avoided Ancillary Services Costs	$3	$3	$3	$3	$3	$3	$9	$9	$9
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$1.4	$5.0	$6.4	$3.0	$11.0	$14.1	$2.0	$8.0	$11.2
Potential Additional Real-Time Benefit	$0.9	$1.6	$1.9	$2.0	$3.4	$4.1	$1.5	$2.4	$3.0
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$26.6	$0.0	$0.0	$26.7	$0.0	$0.0	$92.4
AVERAGE QUANTIFIED BENEFIT **	$95	$99	$139	$97	$105	$147	$227	$233	$358
Low Peak	$86	$88	$127	$88	$93	$133	$206	$209	$330
High Peak	$104	$109	$151	$107	$118	$162	$248	$256	$385

DSM Implemented in:		PJM East			PJM East			PJM East	
Benefits to Customers in:		ACE NJ			All NJ			DPL DE	
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$36	$36	$41	$36	$36	$41	$26	$26	$31
Avoided Energy Costs	$9	$9	$10	$9	$9	$10	$6	$6	$8
Avoided Ancillary Services Costs	$2	$2	$2	$14	$14	$14	$2	$2	$2
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$4.4	$17.1	$23.8	$25.4	$98.8	$137.8	$2.3	$8.6	$11.9
Potential Additional Real-Time Benefit	$2.0	$3.3	$4.0	$15.5	$26.0	$31.4	$1.2	$2.0	$2.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$90.1	$0.0	$0.0	$652.7	$0.0	$0.0	$92.3
AVERAGE QUANTIFIED BENEFIT **	$51	$63	$167	$83	$157	$855	$37	$43	$145
Low Peak	$45	$51	$151	$70	$116	$800	$33	$36	$136
High Peak	$57	$75	$183	$97	$198	$911	$41	$50	$154

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	PEPCO DC			DPL MD			PEPCO MD		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$37	$37	$42	$14	$14	$17	$67	$67	$73
Avoided Energy Costs	$9	$9	$10	$3	$3	$4	$16	$16	$17
Avoided Ancillary Services Costs	$1	$1	$1	$1	$1	$1	$3	$3	$3
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$2.3	$9.0	$12.7	$1.0	$3.6	$5.0	$5.8	$22.6	$31.7
Potential Additional Real-Time Benefit	$1.9	$3.2	$3.9	$0.5	$0.9	$1.0	$4.8	$8.0	$9.7
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$35.2	$0.0	$0.0	$36.1	$0.0	$0.0	$81.3
AVERAGE QUANTIFIED BENEFIT **	$50	$56	$101	$20	$22	$63	$92	$109	$206
Low Peak	$44	$49	$92	$17	$19	$59	$82	$93	$186
High Peak	$55	$64	$111	$22	$25	$67	$102	$124	$226

DSM Implemented in:	PJM East			PJM East			PJM East		
Benefits to Customers in:	All MD			PHI			PJM East		
Supplier Responsiveness Scenario*	Immediate	Slower	Delayed	Immediate	Slower	Delayed	Immediate	Slower	Delayed
RESOURCE COST SAVINGS									
Avoided Capacity Costs	$82	$82	$90	$181	$181	$206	$926	$926	$1,008
Avoided Energy Costs	$20	$20	$22	$43	$43	$49	$222	$222	$242
Avoided Ancillary Services Costs	$10	$10	$10	$9	$9	$9	$45	$45	$45
SHORT-TERM PRICE IMPACTS									
Short-Term Energy Price Benefit	$17.6	$68.7	$96.0	$15.5	$60.4	$84.3	$76.0	$295.7	$412.5
Potential Additional Real-Time Benefit	$13.9	$23.2	$28.1	$10.5	$17.6	$21.3	$46.8	$78.1	$94.5
Short-Term Capacity Market Price Benefit	$0.0	$0.0	$335.3	$0.0	$0.0	$338.5	$0.0	$0.0	$1,290.6
AVERAGE QUANTIFIED BENEFIT **	$128	$179	$553	$249	$294	$687	$1,269	$1,488	$2,998
Low Peak	$113	$147	$510	$222	$249	$629	$1,134	$1,274	$2,731
High Peak	$144	$212	$595	$277	$340	$745	$1,404	$1,703	$3,264

EXHIBIT D

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BPU Docket Nos. EO08050326 and EO07110881

MINIMUM FILING REQUIREMENTS

EXHIBIT D

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

BPU DOCKET N0S. EO08050326 AND EO07110881

MIMIMUM FILING REQUIREMENTS FOR PETITIONS UNDER N.J.S.A. 48:3-98.1

I. General Filing Requirements	Filing Reference
a. The utility shall provide with all filings, information and data pertaining to the specific program proposed, as set forth in applicable sections of N.J.A.C. 14:1-5.11 and N.J.A.C. 14:1-5.12.	Attachment 1 – Comparative Balance Sheet for 3 years – 2005, 2006 and 2007 from FERC FORM 1 Report Attachment 2 – Comparative Income Statement for 3 years – 2005, 2006 and 2007 from FERC FORM 1 Report Attachment 3 – Most recent Balance Sheet – March 2008 from FERC FORM 1 Report Joseph F. Janocha Testimony - Pro-forma Income Statement Attachment 4 – Draft Public Notice Petition - Certification
b. All filings shall contain information and financial statements for the proposed program in accordance with the applicable Uniform System of Accounts that is set forth in N.J.A.C. 14:1-5.12. The utility shall provide the Accounts and Account numbers that will be utilized in booking the revenues, costs, expenses and assets pertaining to each proposed program so that they can be properly separated and allocated from other regulated and/or other programs.	To be provided
c. The utility shall provide supporting explanations, assumptions, calculations, and work papers for each proposed program and cost recovery mechanism petition filed under N.J.S.A. 48:3-98.1 and for all qualitative and quantitative analyses therein. The utility shall provide electronic copies of all materials and supporting schedules, with all inputs and formulae intact.	Joseph F. Janocha Testimony – Schedules JFJ 1-4 (electronic format) Attachment 5 – Summit Blue Report (also in electronic format)
d. The utility shall file testimony supporting its petition.	Steven L. Sunderhauf Testimony Joseph F. Janocha Testimony
e. For any small scale or pilot program, the utility shall only be subject to the requirements in this Section and Sections II, III, and IV. The utility shall, however, provide its estimate of costs and a list of data it intends to collect in a subsequent review of the benefits of the program. Information in Section V may be	Steven L. Sunderhauf Testimony Joseph F. Janocha Testimony

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required for pilot and small programs if such programs are particularly large or complex. A "small scale" project is defined as one that would result in either a rate increase of less than a half of one percent of the average residential customer's bill or an additional annual total revenue requirement of less than $5 million. A pilot program shall be no longer than three years, but can be extended under appropriate circumstances.	
f. If the utility is filing for an increase in rates, charges etc., or for approval of a program which may increase rates/charges to ratepayers in the future, the utility shall include a draft public notice with the petition and proposed publication dates.	Attachment 4 – Draft Public Notice
II. Program Description	**Filing Reference**
a. The utility shall provide a detailed description of each proposed program for which the utility seeks approval.	Steven L. Sunderhauf Testimony
b. The utility shall provide a detailed explanation of the differences and similarities between each proposed program and existing and/or prior programs offered by the New Jersey Clean Energy Program, or the utility.	Steven L. Sunderhauf Testimony
c. The utility shall provide a description of how the proposed program will complement, and impact existing programs being offered by the utility and the New Jersey Clean Energy Program with all supporting documentation.	Steven L. Sunderhauf Testimony
d. The utility shall provide a detailed description of how the proposed program is consistent with and/or different from other utility programs or pilots in place or proposed with all supporting documentation.	Steven L. Sunderhauf Testimony
e. The utility shall provide a detailed description of how the proposed program comports with New Jersey State policy as reflected in reports, including the New Jersey Energy Master Plan, or, pending issuance of the final Energy Master Plan, the draft Energy Master Plan, and the greenhouse gas emissions reports to be issued by the New Jersey Department of Environmental Protection pursuant to N.J.S.A.	To be provided

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

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26:2C-42(b) and (c) and N.J.S.A. 26:2C-43 of the Global Warming Response Act, N.J.S.A. 26:2C-37 et seq.	
f. The utility shall provide the features and benefits for each proposed program including the following: i. the target market and customer eligibility if incentives are to be offered; ii. the program offering and customer incentives; iii. the quality control method including inspection; iv. program administration; and v. program delivery mechanisms.	Steven L. Sunderhauf Testimony
g. The utility shall provide the criteria upon which it chose the program.	Steven L. Sunderhauf Testimony
h. The utility shall provide the estimated program costs by the following categories: administrative (all utility costs), marketing/sales, training, rebates/incentives including inspections and quality control, program implementation (all contract costs) and evaluation and other.	Steven L. Sunderhauf Testimony
i. The utility shall provide the extent to which the utility intends to utilize employees, contractors or both to deliver the program and, to the extent applicable, the criteria the utility will use for contractor selection.	Steven L. Sunderhauf Testimony
j. In the event the program contemplates an agreement between the utility and its contractors and/or the utility and its ratepayers, copies of the proposed standard contract or agreement between the ratepayer and the utility, the contractor and the utility, and/or the contractor and the ratepayer shall be provided.	Attachment 6 – PHI Standard Terms and Conditions for Service Contracts
k. The utility shall provide a detailed description of the process for resolving any customer complaints related to these programs.	Process to be developed and provided
l. The utility shall describe the program goals including number of participants on an annual basis and the energy savings, renewable energy generation and resource savings, both projected annually and over the life of the measures.	Steven L. Sunderhauf Testimony

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m. Marketing – The utility shall provide the following: a description of where and how the proposed program/project will be marketed or promoted throughout the demographic segments of the utility's customer base including an explanation of how prices and the service for each proposed program/project will be conveyed to customers.	Steven L. Sunderhauf Testimony Formal plan to be developed and will be provided.
III. Additional Required Information	**Filing Reference**
a. The utility shall describe whether the proposed programs will generate incremental activity in the energy efficiency/conservation/renewable energy marketplace and what, if any, impact on competition may be created, including any impact on employment, economic development and the development of new business with all supporting documentation. This shall include a breakdown of the impact on the employment within this marketplace as follows: marketing/sales, training, program implementation, installation, equipment, manufacturing and evaluation and other applicable markets. With respect to the impact on competition the analysis should include the competition between utilities and other entities already currently delivering the service in the market or new markets that may be created.	NOT APPLICABLE (filing made as per July 1, 2008 Board Order)
b. The utility shall provide a description of any known market barriers that may impact the program and address the potential impact on such known market barriers for each proposed program with all supporting documentation. This analysis shall include barriers across the various markets including residential (both single and multi-family), commercial and industrial (both privately owned and leased buildings), as well as between small, medium and large commercial and industrial markets. This should include both new development and retrofit or replacement upgrades across the market sectors.	NOT APPLICABLE (filing made as per July 1, 2008 Board Order)

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c. The utility shall provide a qualitative/quantitative description of any anticipated environmental benefits associated with the proposed program and a quantitative estimate of such benefits for the program overall and for each participant in the program with all supporting documentation. This shall include an estimate of the energy saved in kWh and/or therms and the avoided air emissions, wastewater discharges, waste generation and water use or other saved or avoided resources.	NOT APPLICABLE (filing made as per July 1, 2008 Board Order)
d. To the extent known, the utility shall identify whether there are similar programs available in the existing marketplace and provide supporting documentation if applicable. This shall include those programs that provide other societal benefits to other under-served markets. This should include an analysis of the services already provided in the market place, and the level of competition.	NOT APPLICABLE (filing made as per July 1, 2008 Board Order)
e. The utility shall provide an analysis of the benefits or impacts in regard to Smart Growth.	NOT APPLICABLE
f. The utility shall propose the method for treatment of Renewable Energy Certificates ("REC") including solar RECs or any other certificate developed by the Board of Public Utilities, including Greenhouse Gas Emissions Portfolio and Energy Efficiency Portfolio Standards including ownership, and use of the certificate revenue stream(s).	NOT APPLICABLE
g. The utility shall propose the method for treatment of any air emission credits and offsets, including Regional Greenhouse Gas Initiative carbon dioxide allowances and offsets including ownership, and use of the certificate revenue stream(s).	NOT APPLICABLE
h. The utility shall analyze the proposed quantity and expected prices for any REC, solar REC, air emission credits, offsets or allowances or other certificates to the extent possible.	NOT APPLICABLE

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IV. Cost Recovery Mechanism	Filing Reference
a. The utility shall provide appropriate financial data for the proposed program, including estimated revenues, expenses and capitalized investments, for each of the first three years of operations and at the beginning and end of each year of said three-year period. The utility shall include pro forma income statements for the proposed program, for each of the first three years of operations and actual or estimated balance sheets as at the beginning and end of each years of said three year period.	Joseph F. Janocha Testimony
b. shall provide detailed spreadsheets of the accounting treatment of the cost recovery including describing how costs will be amortized, which accounts will be debited or credited each month, and how the costs will flow through the proposed method of recovery of program costs.	Joseph F. Janocha Testimony
c. The utility shall provide a detailed explanation, with all supporting documentation, of the recovery mechanism it proposes to utilize for cost recovery of the proposed program, including proposed recovery through the Societal Benefits Charge, a separate clause established for these programs, base rate revenue requirements, government funding reimbursement, retail margin, and/or other.	Joseph F. Janocha Testimony
d. The utility's petition for approval, including proposed tariff sheets and other required information, shall be verified as to its accuracy and shall be accompanied by a certification of service demonstrating that the petition was served on the Department of the Public Advocate, Division of Rate Counsel simultaneous to its submission to the Board.	Joseph F. Janocha Testimony
e. The utility shall provide an annual rate impact summary by year for the proposed program, and an annual cumulative rate impact summary for all approved and proposed programs showing the impact of individual programs as well as the cumulative impact of	Joseph F. Janocha Testimony

all programs upon each customer class of implementing each program and all approved and proposed programs based upon a revenue requirement analysis that identifies all estimated program costs and revenues for each proposed program on an annual basis. The utility shall also provide an annual bill impact summary by year for each program, and an annual cumulative bill impact summary by year for all approved and proposed programs showing bill impacts on a typical customer for each class.	
f. The utility shall provide, with supporting documentation, a detailed breakdown of the total costs for the proposed program, identified by cost segment (capitalized costs, operating expense, administrative expense, etc.). This shall also include a detailed analysis and breakdown and separation of the embedded and incremental costs that will be incurred to provide the services under the proposed program with all supporting documentation.	Steven L. Sunderhauf Testimony
g. The utility shall provide a detailed revenue requirement analysis that clearly identifies all estimated program costs and revenues for the proposed program on an annual basis, including effects upon rate base and pro forma income calculations.	Joseph F. Janocha Testimony
h. The utility shall provide, with supporting documentation: (i) a calculation of its current capital structure as well as its calculation of the capital structure approved by the Board in its most recent electric and/or gas base rate cases, and (ii) a statement as to its allowed overall rate of return approved by the Board in its most recent electric and/or gas base rate cases.	Joseph F. Janocha Testimony
i. If the utility is seeking carrying costs for a proposed program, the filing shall include a description of the methodology, capital structure, and capital cost rates used by the utility.	NOT APPLICABLE

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j. A utility seeking incentives or rate mechanism that decouples utility revenues from sales, shall provide all supporting justification, and rationale for incentives, along with supporting documentation, assumptions and calculations.	Joseph F. Janocha Testimony
V. Cost/Benefit Analysis	**Filing Reference**
a. The utility shall provide a detailed analysis with supporting documentation of the net benefits associated with the proposed program, including, if appropriate, a comprehensive and detailed avoided cost savings study with supporting documentation. The value of the avoided environmental impacts and the environmental benefits and the value of any avoided or deferred energy infrastructure should be stated separately.	NOT APPLICABLE
b. The utility shall calculate a cost/benefit analysis utilizing the Total Resource Cost ("TRC") test that assesses all program costs and benefits from a societal perspective. The utility may also provide any cost benefit analysis that it believes appropriate with supporting rationales and documentation.	NOT APPLICABLE
c. The utility shall quantify all direct and indirect benefits as well as provide projected costs resulting from a proposed program that is subject to a cost/benefit test.	NOT APPLICABLE
d. Renewable energy programs shall not be subject to a cost/benefit test but the utility must quantify all direct and indirect benefits resulting from such a proposed program as well as provide the projected costs. The utility must also demonstrate how such a proposed program will support energy and environmental statewide planning objectives, such as attainment of the Renewable Portfolio Standard and any emission requirements.	NOT APPLICABLE

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e. The utility must demonstrate for the proposed program that it results in a positive benefit/cost ratio, or, if the utility cannot make such a demonstration, it must provide the rationale for why the proposed program should be approved.	NOT APPLICABLE
f. The level of energy and capacity savings utilized in these calculations shall be based upon the most recent protocols approved by the Board of Public Utilities to measure energy savings for the New Jersey Clean Energy Program. In the event no such protocols exist, or to the extent that a protocol does not exist for a filed program, the utility must submit a measurement protocol for the program or contemplated measure for approval by the Board.	NOT APPLICABLE
g. The utility shall also quantify and deduct from the energy and capacity savings any free rider effects and the business as usual benefits from homeowners and businesses installing Energy Efficiency or Renewable Energy without the N.J.S.A. 48:3-98.1 benefits or incentives.	NOT APPLICABLE

Atlantic City Electric Company
Comparative Balance Sheet
Assets

	FERC FORM NO. 1		
ACCOUNTS	2007	2006	2005
1 UTILITY PLANT			
2 Utility Plant (101-106, 114)	$1,955,208,578.00	$1,940,621,122.00	$1,857,360,758.00
3 Construction Work in Progress (107)	$121,443,556.00	$71,366,100.00	$56,832,094.00
4 TOTAL Utility Plant (Enter Total of lines 2 and 3)	$2,076,652,134.00	$2,011,987,222.00	$1,914,192,852.00
5 (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	$633,518,715.00	$629,819,870.00	$585,280,042.00
6 Net Utility Plant (Enter Total of line 4 less 5)	$1,443,133,419.00	$1,382,167,352.00	$1,328,912,810.00
7 Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	$0.00	$0.00	$0.00
8 Nuclear Fuel Materials and Assemblies-Stock Account (120.2)	$0.00	$0.00	$0.00
9 Nuclear Fuel Assemblies in Reactor (120.3)	$0.00	$0.00	$0.00
10 Spent Nuclear Fuel (120.4)	$0.00	$0.00	$0.00
11 Nuclear Fuel Under Capital Leases (120.6)	$0.00	$0.00	$0.00
12 (Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	$0.00	$0.00	$0.00
13 Net Nuclear Fuel (Enter Total of lines 7-11 less 12)	$0.00	$0.00	$0.00
14 Net Utility Plant (Enter Total of lines 6 and 13)	$1,443,133,419.00	$1,382,167,352.00	$1,328,912,810.00
15 Utility Plant Adjustments (116)	$0.00	$0.00	$0.00
16 Gas Stored Underground - Noncurrent (117)	$0.00	$0.00	$0.00
17 OTHER PROPERTY AND INVESTMENTS	$0.00	$0.00	$0.00
18 Nonutility Property (121)	$1,339,040.00	$1,339,040.00	$1,339,040.00
19 (Less) Accum. Prov. for Depr. and Amort. (122)	$0.00	$0.00	$0.00
20 Investments in Associated Companies (123)	$0.00	$0.00	$0.00
21 Investment in Subsidiary Companies (123.1)	$2,960,001.00	$2,960,001.00	$2,960,001.00
22 (For Cost of Account 123.1, See Footnote Page 224, line 42)	$0.00	$0.00	$0.00
23 Noncurrent Portion of Allowances	$0.00	$0.00	$0.00
24 Other Investments (124)	$0.00	$0.00	$0.00
25 Sinking Funds (125)	$0.00	$0.00	$0.00
26 Depreciation Fund (126)	$0.00	$0.00	$0.00
27 Amortization Fund - Federal (127)	$0.00	$0.00	$0.00
28 Other Special Funds (128)	$1,026,290.00	$6,213,958.00	$6,199,037.00
29 Special Funds (Non Major Only) (129)	$0.00	$0.00	$0.00
30 Long-Term Portion of Derivative Assets (175)	$0.00	$0.00	$0.00
31 Long-Term Portion of Derivative Assets – Hedges (176)	$0.00	$0.00	$0.00
32 TOTAL Other Property and Investments (Lines 18-21 and 23-31)	$5,325,331.00	$10,512,999.00	$10,498,078.00
33 CURRENT AND ACCRUED ASSETS	$0.00	$0.00	$0.00
34 Cash and Working Funds (Non-major Only) (130)	$0.00	$0.00	$0.00
35 Cash (131)	$7,014,464.00	$5,365,268.00	$3,819,631.00
36 Special Deposits (132-134)	$0.00	$4,040,296.00	$0.00
37 Working Fund (135)	$133,636.00	$145,107.00	$412,382.00
38 Temporary Cash Investments (136)	$0.00	$0.00	$0.00
39 Notes Receivable (141)	$0.00	$0.00	$0.00
40 Customer Accounts Receivable (142)	$119,333,686.00	$97,203,059.00	$94,329,211.00
41 Other Accounts Receivable (143)	$42,209,327.00	$36,173,997.00	$70,322,695.00
42 (Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	$4,896,000.00	$5,457,462.00	$5,153,079.00
43 Notes Receivable from Associated Companies (145)	$0.00	$0.00	$4,042,005.00
44 Accounts Receivable from Assoc. Companies (146)	$0.00	$0.00	$0.00
45 Fuel Stock (151)	$0.00	$7,898,180.00	$20,746,643.00
46 Fuel Stock Expenses Undistributed (152)	$0.00	$0.00	$0.00
47 Residuals (Elec) and Extracted Products (153)	$0.00	$0.00	$0.00
48 Plant Materials and Operating Supplies (154)	$12,973,200.00	$17,021,299.00	$15,604,463.00
49 Merchandise (155)	$0.00	$0.00	$0.00
50 Other Materials and Supplies (156)	$0.00	$0.00	$0.00
51 Nuclear Materials Held for Sale (157)	$0.00	$0.00	$0.00
52 Allowances (158.1 and 158.2)	$121,288.00	$442,694.00	$1,790,655.00
53 (Less) Noncurrent Portion of Allowances	$0.00	$0.00	$0.00
54 Stores Expense Undistributed (163)	$1,031,369.00	$1,684,512.00	$1,427,523.00
55 Gas Stored Underground - Current (164.1)	$0.00	$0.00	$0.00
56 Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	$0.00	$0.00	$0.00
57 Prepayments (165)	$57,140,806.00	$66,428,998.00	$9,930,540.00
58 Advances for Gas (166-167)	$0.00	$0.00	$0.00
59 Interest and Dividends Receivable (171)	$0.00	$0.00	$507,329.00
60 Rents Receivable (172)	$3,293,300.00	$3,273,785.00	$3,954,507.00
61 Accrued Utility Revenues (173)	$38,129,515.00	$31,830,243.00	$42,025,983.00
62 Miscellaneous Current and Accrued Assets (174)	$0.00	$0.00	$0.00
63 Derivative Instrument Assets (175)	$0.00	$0.00	$0.00
64 (Less) Long-Term Portion of Derivative Instrument Assets (175)	$0.00	$0.00	$0.00
65 Derivative Instrument Assets - Hedges (176)	$0.00	$0.00	$0.00
66 (Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176	$0.00	$0.00	$0.00
67 Total Current and Accrued Assets (Lines 34 through 66)	$276,484,591.00	$266,049,976.00	$263,760,486.00
68 DEFERRED DEBITS	$0.00	$0.00	$0.00
69 Unamortized Debt Expenses (181)	$4,713,966.00	$4,964,861.00	$4,561,214.00
70 Extraordinary Property Losses (182.1)	$0.00	$0.00	$0.00
71 Unrecovered Plant and Regulatory Study Costs (182.2)	$0.00	$0.00	$0.00
72 Other Regulatory Assets (182.3)	$818,753,197.00	$903,054,850.00	$1,031,092,650.00
73 Prelim. Survey and Investigation Charges (Electric) (183)	$53,934.00	$39,677.00	$0.00
74 Preliminary Natural Gas Survey and Investigation Charges 183.1)	$0.00	$0.00	$0.00
75 Other Preliminary Survey and Investigation Charges (183.2)	$0.00	$0.00	$0.00
76 Clearing Accounts (184)	($2,412,729.00)	($2,662,630.00)	($84,440.00)
77 Temporary Facilities (185)	$0.00	$0.00	$0.00
78 Miscellaneous Deferred Debits (186)	$42,986,206.00	$29,632,647.00	$17,908,941.00
79 Def. Losses from Disposition of Utility Plt. (187)	$0.00	$0.00	$0.00
80 Research, Devel. and Demonstration Expend. (188)	$0.00	$0.00	$0.00
81 Unamortized Loss on Reaquired Debt (189)	$14,101,084.00	$15,341,732.00	$16,586,877.00
82 Accumulated Deferred Income Taxes (190)	$129,118,987.00	$119,163,130.00	$125,381,158.00
83 Unrecovered Purchased Gas Costs (191)	$0.00	$0.00	$0.00
84 Total Deferred Debits (lines 69 through 83)	$1,007,314,645.00	$1,069,534,267.00	$1,195,446,400.00
85 TOTAL ASSETS (lines 14-16, 32, 67, and 84)	$2,732,257,986.00	$2,728,264,594.00	$2,798,617,776.00

Atlantic City Electric Company
Comparative Balance Sheet
Liabilities

ACCOUNTS	FERC FORM NO. 1 2007	2006	2005
1 PROPRIETARY CAPITAL			
2 Common Stock Issued (201)	$25,638,051.00	$25,638,051.00	$25,638,051.00
3 Preferred Stock Issued (204)	$6,214,500.00	$6,214,500.00	$6,214,500.00
4 Capital Stock Subscribed (202, 205)	$0.00	$0.00	$0.00
5 Stock Liability for Conversion (203, 206)	$0.00	$0.00	$0.00
6 Premium on Capital Stock (207)	$107,755,439.00	$107,755,439.00	$107,755,439.00
7 Other Paid-In Capital (208-211)	$202,755,707.00	$199,734,733.00	$186,273,658.00
8 Installments Received on Capital Stock (212)	$0.00	$0.00	$0.00
9 (Less) Discount on Capital Stock (213)	$0.00	$0.00	$0.00
10 (Less) Capital Stock Expense (214)	$574,285.00	$574,285.00	$574,285.00
11 Retained Earnings (215, 215.1, 216)	$141,846,141.00	$132,006,896.00	$178,619,821.00
12 Unappropriated Undistributed Subsidiary Earnings (216.1)	$0.00	$0.00	$0.00
13 (Less) Reaquired Capital Stock (217)	$0.00	$0.00	$0.00
14 Noncorporate Proprietorship (Non-major only) (218)	$0.00	$0.00	$0.00
15 Accumulated Other Comprehensive Income (219)	$0.00	$0.00	$0.00
16 Total Proprietary Capital (lines 2 through 15)	$483,635,553.00	$470,775,334.00	$503,927,184.00
17 LONG-TERM DEBT	$0.00	$0.00	$0.00
18 Bonds (221)	$438,715,000.00	$438,715,000.00	$333,715,000.00
19 (Less) Reaquired Bonds (222)	$0.00	$0.00	$0.00
20 Advances from Associated Companies (223)	$450,656,501.00	$469,505,563.00	$501,558,253.00
21 Other Long-Term Debt (224)	$50,000,000.00	$66,000,000.00	$131,000,000.00
22 Unamortized Premium on Long-Term Debt (225)	$0.00	$0.00	$0.00
23 (Less) Unamortized Discount on Long-Term Debt-Debit (226)	$396,669.00	$422,136.00	$447,603.00
24 Total Long-Term Debt (lines 18 through 23)	$938,974,832.00	$973,798,427.00	$965,825,650.00
25 OTHER NONCURRENT LIABILITIES	$0.00	$0.00	$0.00
26 Obligations Under Capital Leases - Noncurrent (227)	$0.00	$0.00	$189,545.00
27 Accumulated Provision for Property Insurance (228.1)	$0.00	$0.00	$0.00
28 Accumulated Provision for Injuries and Damages (228.2)	$0.00	$0.00	$0.00
29 Accumulated Provision for Pensions and Benefits (228.3)	$0.00	$0.00	$2,909,100.00
30 Accumulated Miscellaneous Operating Provisions (228.4)	$0.00	$0.00	$0.00
31 Accumulated Provision for Rate Refunds (229)	$0.00	$0.00	$0.00
32 Long-Term Portion of Derivative Instrument Liabilities	$0.00	$0.00	$0.00
33 Long-Term Portion of Derivative Instrument Liabilities - Hedges	$0.00	$0.00	$0.00
34 Asset Retirement Obligations (230)	$122,107.00	$63,357,915.00	$0.00
35 Total Other Noncurrent Liabilities (lines 26 through 34)	$122,107.00	$63,357,915.00	$3,098,645.00
36 CURRENT AND ACCRUED LIABILITIES	$0.00	$0.00	$0.00
37 Notes Payable (231)	$29,096,160.00	$1,199,818.00	$0.00
38 Accounts Payable (232)	$96,596,081.00	$80,670,339.00	$152,275,937.00
39 Notes Payable to Associated Companies (233)	$0.00	$0.00	$0.00
40 Accounts Payable to Associated Companies (234)	$18,311,702.00	$27,318,253.00	$38,332,070.00
41 Customer Deposits (235)	$20,659,857.00	$19,492,095.00	$16,966,232.00
42 Taxes Accrued (236)	$25,297,304.00	$8,504,565.00	$75,805,836.00
43 Interest Accrued (237)	$8,807,059.00	$9,036,267.00	$8,082,338.00
44 Dividends Declared (238)	$43,807.00	$43,807.00	$43,807.00
45 Matured Long-Term Debt (239)	$0.00	$0.00	$0.00
46 Matured Interest (240)	$0.00	$0.00	$0.00
47 Tax Collections Payable (241)	$0.00	$142,450.00	$142,450.00
48 Miscellaneous Current and Accrued Liabilities (242)	$137,195,856.00	$136,773,133.00	$150,210,508.00
49 Obligations Under Capital Leases-Current (243)	$0.00	$0.00	$18,059.00
50 Derivative Instrument Liabilities (244)	$0.00	$0.00	$0.00
51 (Less) Long-Term Portion of Derivative Instrument Liabilities	$0.00	$0.00	$0.00
52 Derivative Instrument Liabilities - Hedges (245)	$0.00	$0.00	$0.00
53 (Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges	$0.00	$0.00	$0.00
54 Total Current and Accrued Liabilities (lines 37 through 53)	$336,007,826.00	$283,180,727.00	$441,877,237.00
55 DEFERRED CREDITS	$0.00	$0.00	$0.00
56 Customer Advances for Construction (252)	$438,736.00	$567,071.00	$677,141.00
57 Accumulated Deferred Investment Tax Credits (255)	$11,059,154.00	$14,942,923.00	$16,505,493.00
58 Deferred Gains from Disposition of Utility Plant (256)	$0.00	$0.00	$0.00
59 Other Deferred Credits (253)	$4,936,944.00	$13,236,626.00	$9,297,479.00
60 Other Regulatory Liabilities (254)	$433,443,068.00	$360,808,520.00	$309,904,957.00
61 Unamortized Gain on Reaquired Debt (257)	$0.00	$0.00	$0.00
62 Accum. Deferred Income Taxes-Accel. Amort.(281)	$0.00	$0.00	$0.00
63 Accum. Deferred Income Taxes-Other Property (282)	$500,647,370.00	$459,138,014.00	$404,102,260.00
64 Accum. Deferred Income Taxes-Other (283)	$22,992,396.00	$88,459,037.00	$143,401,730.00
65 Total Deferred Credits (lines 56 through 64)	$973,517,668.00	$937,152,191.00	$883,889,060.00
66 TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54,65)	$2,732,257,986.00	$2,728,264,594.00	$2,798,617,776.00

Atlantic City Electric Company
Comparative Income Statement

FERC FORM NO. 1

Account	2007	2006	2005
1 UTILITY OPERATING INCOME			
2 Operating Revenues (400)	$1,556,072,815.00	$1,491,679,944.00	$1,025,348,479.00
3 Operating Expenses	$0.00	$0.00	$0.00
4 Operation Expenses (401)	$1,262,158,048.00	$1,149,891,474.00	$676,478,223.00
5 Maintenance Expenses (402)	$23,029,213.00	$41,262,792.00	$38,589,755.00
6 Depreciation Expense (403)	$50,670,278.00	$48,529,835.00	$50,867,672.00
7 Depreciation Expense for Asset Retirement Costs (403.1)	$0.00	$0.00	$0.00
8 Amort. & Depl. of Utility Plant (404-405)	($12,712,445.00)	($10,698,422.00)	($4,645,861.00)
9 Amort. of Utility Plant Acq. Adj. (406)	$0.00	$0.00	$0.00
10 Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)	$0.00	$0.00	$0.00
11 Amort. of Conversion Expenses (407)	$0.00	$0.00	$0.00
12 Regulatory Debits (407.3)	$42,193,087.00	$73,577,159.00	$77,722,569.00
13 (Less) Regulatory Credits (407.4)	$0.00	$0.00	$2,244,172.00
14 Taxes Other Than Income Taxes (408.1)	$26,087,232.00	$29,959,741.00	$29,353,089.00
15 Income Taxes - Federal (409.1)	$60,950,345.00	$20,203,418.00	$105,349,795.00
16 - Other (409.1)	$14,703,196.00	$11,540,138.00	$22,725,137.00
17 Provision for Deferred Income Taxes (410.1)	$87,626,164.00	$151,483,525.00	$36,347,012.00
18 (Less) Provision for Deferred Income Taxes-Cr. (411.1)	$122,030,300.00	$147,844,736.00	$119,420,200.00
19 Investment Tax Credit Adj. - Net (411.4)	$127,106.00	($1,366,091.00)	($1,002,312.00)
20 (Less) Gains from Disp. of Utility Plant (411.6)	$0.00	$0.00	$0.00
21 Losses from Disp. of Utility Plant (411.7)	$0.00	$0.00	$0.00
22 (Less) Gains from Disposition of Allowances (411.8)	$0.00	$0.00	$0.00
23 Losses from Disposition of Allowances (411.9)	$0.00	$0.00	$0.00
24 Accretion Expense (411.10)	$0.00	$0.00	$0.00
25 TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)	$1,432,801,924.00	$1,366,538,833.00	$910,120,707.00
26 Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27	$123,270,891.00	$125,141,111.00	$115,227,772.00
27 Net Utility Operating Income (Carried forward from page 114)	$123,270,891.00	$125,141,111.00	$115,227,772.00
28 Other Income and Deductions	$0.00	$0.00	$0.00
29 Other Income	$0.00	$0.00	$0.00
30 Nonutilty Operating Income	$0.00	$0.00	$0.00
31 Revenues From Merchandising, Jobbing and Contract Work (415)	$5,716,154.00	$5,601,053.00	$6,879,123.00
32 (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)	$7,894,108.00	$7,067,677.00	$7,930,355.00
33 Revenues From Nonutility Operations (417)	$114,850.00	$159,068.00	$338,184.00
34 (Less) Expenses of Nonutility Operations (417.1)	$953,046.00	$1,816,761.00	$10,036,277.00
35 Nonoperating Rental Income (418)	$0.00	$0.00	$0.00
36 Equity in Earnings of Subsidiary Companies (418.1)	$0.00	$0.00	$0.00
37 Interest and Dividend Income (419)	$807,413.00	$2,189,448.00	$2,185,836.00
38 Allowance for Other Funds Used During Construction (419.1)	$1,085,799.00	$675,442.00	$1,584,040.00
39 Miscellaneous Nonoperating Income (421)	$3,993,026.00	$1,858,942.00	$4,608,387.00
40 Gain on Disposition of Property (421.1)	$376,613.00	$108.00	$101,725.00
41 TOTAL Other Income (Enter Total of lines 31 thru 40)	$3,246,701.00	$1,599,623.00	($2,269,337.00)
42 Other Income Deductions	$0.00	$0.00	$0.00
43 Loss on Disposition of Property (421.2)	$0.00	$0.00	$0.00
44 Miscellaneous Amortization (425)	$0.00	$0.00	$0.00
45 Donations (426.1)	$110,296.00	$186,168.00	$161,674.00
46 Life Insurance (426.2)	($235,404.00)	($445,052.00)	$0.00
47 Penalties (426.3)	$51,453.00	$80,239.00	$45,074.00
48 Exp. for Certain Civic, Political & Related Activities (426.4)	$84,733.00	$30,623.00	$0.00
49 Other Deductions (426.5)	$3,253,053.00	$12,012.00	$0.00
50 TOTAL Other Income Deductions (Total of lines 43 thru 49)	$3,264,131.00	($136,010.00)	$206,748.00
51 Taxes Applic. to Other Income and Deductions	$0.00	$0.00	$0.00
52 Taxes Other Than Income Taxes (408.2)	$0.00	$0.00	$0.00
53 Income Taxes-Federal (409.2)	$577,414.00	$653,006.00	($546,242.00)
54 Income Taxes-Other (409.2)	$163,162.00	$184,523.00	($154,354.00)
55 Provision for Deferred Inc. Taxes (410.2)	$0.00	$0.00	$0.00
56 (Less) Provision for Deferred Income Taxes-Cr. (411.2)	$0.00	$0.00	$0.00
57 Investment Tax Credit Adj.-Net (411.5)	$0.00	$0.00	$0.00
58 (Less) Investment Tax Credits (420)	$0.00	$0.00	$0.00
59 TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)	$740,576.00	$837,529.00	($700,596.00)
60 Net Other Income and Deductions (Total of lines 41, 50, 59)	($758,006.00)	$898,104.00	($1,775,489.00)
61 Interest Charges	$0.00	$0.00	$0.00
62 Interest on Long-Term Debt (427)	$28,943,604.00	$28,562,883.00	$27,993,765.00
63 Amort. of Debt Disc. and Expense (428)	$1,720,303.00	$2,491,690.00	$1,509,624.00
64 Amortization of Loss on Reaquired Debt (428.1)	$1,240,648.00	$1,245,145.00	$1,245,145.00
65 (Less) Amort. of Premium on Debt-Credit (429)	$0.00	$0.00	$0.00
66 (Less) Amortization of Gain on Reaquired Debt-Credit (429.1)	$0.00	$0.00	$0.00
67 Interest on Debt to Assoc. Companies (430)	$23,508,077.00	$24,476,852.00	$26,074,634.00
68 Other Interest Expense (431)	$8,821,831.00	$7,372,406.00	$3,214,131.00
69 (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)	$1,830,348.00	$759,674.00	$761,038.00
70 Net Interest Charges (Total of lines 62 thru 69)	$62,404,115.00	$63,389,302.00	$59,276,261.00
71 Income Before Extraordinary Items (Total of lines 27, 60 and 70)	$60,108,770.00	$62,649,913.00	$54,176,022.00
72 Extraordinary Items	$0.00	$0.00	$0.00
73 Extraordinary Income (434)	$0.00	$0.00	$0.00
74 (Less) Extraordinary Deductions (435)	$0.00	$0.00	($15,195,721.00)
75 Net Extraordinary Items (Total of line 73 less line 74)	$0.00	$0.00	$15,195,721.00
76 Income Taxes-Federal and Other (409.3)	$0.00	$0.00	$6,207,452.00
77 Extraordinary Items After Taxes (line 75 less line 76)	$0.00	$0.00	$8,988,269.00
78 Net Income (Total of line 71 and 77)	$60,108,770.00	$62,649,913.00	$63,164,291.00

Atlantic City Electric Company
Balance Sheet
Assets- March 2008

ACCOUNTS	FERC FORM NO. 1 1 Q 31-Mar-08
1 UTILITY PLANT	
2 Utility Plant (101-106, 114)	$1,977,239,919.00
3 Construction Work in Progress (107)	$146,919,775.00
4 TOTAL Utility Plant (Enter Total of lines 2 and 3)	$2,124,159,694.00
5 (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	$640,531,137.00
6 Net Utility Plant (Enter Total of line 4 less 5)	$1,483,628,557.00
7 Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	$0.00
8 Nuclear Fuel Materials and Assemblies-Stock Account (120.2)	$0.00
9 Nuclear Fuel Assemblies in Reactor (120.3)	$0.00
10 Spent Nuclear Fuel (120.4)	$0.00
11 Nuclear Fuel Under Capital Leases (120.6)	$0.00
12 (Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	$0.00
13 Net Nuclear Fuel (Enter Total of lines 7-11 less 12)	$0.00
14 Net Utility Plant (Enter Total of lines 6 and 13)	$1,483,628,557.00
15 Utility Plant Adjustments (116)	$0.00
16 Gas Stored Underground - Noncurrent (117)	$0.00
17 OTHER PROPERTY AND INVESTMENTS	$0.00
18 Nonutility Property (121)	$1,339,040.00
19 (Less) Accum. Prov. for Depr. and Amort. (122)	$0.00
20 Investments in Associated Companies (123)	$0.00
21 Investment in Subsidiary Companies (123.1)	$2,960,001.00
22 (For Cost of Account 123.1, See Footnote Page 224, line 42)	$0.00
23 Noncurrent Portion of Allowances	$0.00
24 Other Investments (124)	$0.00
25 Sinking Funds (125)	$0.00
26 Depreciation Fund (126)	$0.00
27 Amortization Fund - Federal (127)	$0.00
28 Other Special Funds (128)	$961,222.00
29 Special Funds (Non Major Only) (129)	$0.00
30 Long-Term Portion of Derivative Assets (175)	$0.00
31 Long-Term Portion of Derivative Assets – Hedges (176)	$0.00
32 TOTAL Other Property and Investments (Lines 18-21 and 23-31)	$5,260,263.00
33 CURRENT AND ACCRUED ASSETS	$0.00
34 Cash and Working Funds (Non-major Only) (130)	$0.00
35 Cash (131)	$8,158,026.00
36 Special Deposits (132-134)	$0.00
37 Working Fund (135)	$132,102.00
38 Temporary Cash Investments (136)	$2,700,239.00
39 Notes Receivable (141)	$0.00
40 Customer Accounts Receivable (142)	$114,823,339.00
41 Other Accounts Receivable (143)	$43,395,933.00
42 (Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	$5,502,187.00
43 Notes Receivable from Associated Companies (145)	$0.00
44 Accounts Receivable from Assoc. Companies (146)	$0.00
45 Fuel Stock (151)	$0.00
46 Fuel Stock Expenses Undistributed (152)	$0.00
47 Residuals (Elec) and Extracted Products (153)	$0.00
48 Plant Materials and Operating Supplies (154)	$13,914,257.00
49 Merchandise (155)	$0.00
50 Other Materials and Supplies (156)	$0.00
51 Nuclear Materials Held for Sale (157)	$0.00
52 Allowances (158.1 and 158.2)	$121,289.00
53 (Less) Noncurrent Portion of Allowances	$0.00
54 Stores Expense Undistributed (163)	$854,335.00
55 Gas Stored Underground - Current (164.1)	$0.00
56 Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	$0.00
57 Prepayments (165)	$55,390,448.00
58 Advances for Gas (166-167)	$0.00
59 Interest and Dividends Receivable (171)	$0.00
60 Rents Receivable (172)	$4,833,950.00
61 Accrued Utility Revenues (173)	$20,374,285.00
62 Miscellaneous Current and Accrued Assets (174)	$0.00
63 Derivative Instrument Assets (175)	$0.00
64 (Less) Long-Term Portion of Derivative Instrument Assets (175)	$0.00
65 Derivative Instrument Assets - Hedges (176)	$0.00
66 (Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176	$0.00
67 Total Current and Accrued Assets (Lines 34 through 66)	$259,196,016.00
68 DEFERRED DEBITS	$0.00
69 Unamortized Debt Expenses (181)	$4,182,803.00
70 Extraordinary Property Losses (182.1)	$0.00
71 Unrecovered Plant and Regulatory Study Costs (182.2)	$0.00
72 Other Regulatory Assets (182.3)	$768,223,124.00
73 Prelim. Survey and Investigation Charges (Electric) (183)	$8,000.00
74 Preliminary Natural Gas Survey and Investigation Charges 183.1)	$0.00
75 Other Preliminary Survey and Investigation Charges (183.2)	$0.00
76 Clearing Accounts (184)	($819,701.00)
77 Temporary Facilities (185)	$0.00
78 Miscellaneous Deferred Debits (186)	$38,833,656.00
79 Def. Losses from Disposition of Utility Plt. (187)	$0.00
80 Research, Devel. and Demonstration Expend. (188)	$0.00
81 Unamortized Loss on Reaquired Debt (189)	$14,238,519.00
82 Accumulated Deferred Income Taxes (190)	$138,438,689.00
83 Unrecovered Purchased Gas Costs (191)	$0.00
84 Total Deferred Debits (lines 69 through 83)	$963,105,090.00
85 TOTAL ASSETS (lines 14-16, 32, 67, and 84)	$2,711,189,926.00

Atlantic City Electric Company
Balance Sheet
Liabilities - March 2008

ACCOUNTS	FERC FORM NO. 1 1 Q 31-Mar-08
1 PROPRIETARY CAPITAL	
2 Common Stock Issued (201)	$25,638,051.00
3 Preferred Stock Issued (204)	$6,214,500.00
4 Capital Stock Subscribed (202, 205)	$0.00
5 Stock Liability for Conversion (203, 206)	$0.00
6 Premium on Capital Stock (207)	$107,755,439.00
7 Other Paid-In Capital (208-211)	$237,755,707.00
8 Installments Received on Capital Stock (212)	$0.00
9 (Less) Discount on Capital Stock (213)	$0.00
10 (Less) Capital Stock Expense (214)	$574,285.00
11 Retained Earnings (215, 215.1, 216)	$147,052,494.00
12 Unappropriated Undistributed Subsidiary Earnings (216.1)	$0.00
13 (Less) Reaquired Capital Stock (217)	$0.00
14 Noncorporate Proprietorship (Non-major only) (218)	$0.00
15 Accumulated Other Comprehensive Income (219)	$0.00
16 Total Proprietary Capital (lines 2 through 15)	$523,841,906.00
17 LONG-TERM DEBT	$0.00
18 Bonds (221)	$413,715,000.00
19 (Less) Reaquired Bonds (222)	$0.00
20 Advances from Associated Companies (223)	$444,593,525.00
21 Other Long-Term Debt (224)	$35,000,000.00
22 Unamortized Premium on Long-Term Debt (225)	$0.00
23 (Less) Unamortized Discount on Long-Term Debt-Debit (226)	$390,319.00
24 Total Long-Term Debt (lines 18 through 23)	$892,918,206.00
25 OTHER NONCURRENT LIABILITIES	$0.00
26 Obligations Under Capital Leases - Noncurrent (227)	$0.00
27 Accumulated Provision for Property Insurance (228.1)	$0.00
28 Accumulated Provision for Injuries and Damages (228.2)	$0.00
29 Accumulated Provision for Pensions and Benefits (228.3)	$0.00
30 Accumulated Miscellaneous Operating Provisions (228.4)	$0.00
31 Accumulated Provision for Rate Refunds (229)	$0.00
32 Long-Term Portion of Derivative Instrument Liabilities	$0.00
33 Long-Term Portion of Derivative Instrument Liabilities - Hedges	$0.00
34 Asset Retirement Obligations (230)	$124,519.00
35 Total Other Noncurrent Liabilities (lines 26 through 34)	$124,519.00
36 CURRENT AND ACCRUED LIABILITIES	$0.00
37 Notes Payable (231)	$35,000,000.00
38 Accounts Payable (232)	$85,189,142.00
39 Notes Payable to Associated Companies (233)	$0.00
40 Accounts Payable to Associated Companies (234)	$23,040,461.00
41 Customer Deposits (235)	$20,662,657.00
42 Taxes Accrued (236)	$20,442,230.00
43 Interest Accrued (237)	$6,852,792.00
44 Dividends Declared (238)	$43,807.00
45 Matured Long-Term Debt (239)	$0.00
46 Matured Interest (240)	$0.00
47 Tax Collections Payable (241)	$0.00
48 Miscellaneous Current and Accrued Liabilities (242)	$96,525,764.00
49 Obligations Under Capital Leases-Current (243)	$0.00
50 Derivative Instrument Liabilities (244)	$0.00
51 (Less) Long-Term Portion of Derivative Instrument Liabilities	$0.00
52 Derivative Instrument Liabilities - Hedges (245)	$0.00
53 (Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges	$0.00
54 Total Current and Accrued Liabilities (lines 37 through 53)	$287,756,853.00
55 DEFERRED CREDITS	$0.00
56 Customer Advances for Construction (252)	$425,941.00
57 Accumulated Deferred Investment Tax Credits (255)	$10,803,762.00
58 Deferred Gains from Disposition of Utility Plant (256)	$0.00
59 Other Deferred Credits (253)	$5,118,105.00
60 Other Regulatory Liabilities (254)	$457,403,841.00
61 Unamortized Gain on Reaquired Debt (257)	$0.00
62 Accum. Deferred Income Taxes-Accel. Amort.(281)	$0.00
63 Accum. Deferred Income Taxes-Other Property (282)	$510,139,255.00
64 Accum. Deferred Income Taxes-Other (283)	$22,657,538.00
65 Total Deferred Credits (lines 56 through 64)	$1,006,548,442.00
66 TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)	$2,711,189,926.00

DRAFT PUBLIC NOTICE

NOTICE OF
FILING AND PUBLIC HEARING
TO CUSTOMERS OF
ATLANTIC CITY ELECTRIC COMPANY

IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S RESPONSIVE PETITION TO THE BOARD OF PUBLIC UTILITIES ORDER DATED JULY 1, 2008 REGARDING THE SUBMISSION OF DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 FOR ELECTRIC DISTRIBUTION COMPANIES, AND FOR SUPPLEMENTAL INCLUSION OF SAME IN ITS "BLUEPRINT FOR THE FUTURE" FILING DATED NOVEMBER, 19, 2007

Docket Nos. EO08050326 and EO07110881

PLEASE TAKE NOTICE that, on August 1, 2008, Atlantic City Electric Company ("ACE" or the "Company") filed for approval with respect to its proposal for demand response programs designed to be implemented by June 2009 to reduce electricity demands on its system during periods of high market prices.

In response to the Board's July 1, 2008 Order in Docket. No. EO08050326, the Company seeks the cost recovery authorizations to enable the Company to commit the necessary financial resources to make its proposed Demand Response program a reality for ACE's New Jersey customers. ACE is seeking authorization to recover program costs for the demand response program proposed in its filing through the existing System Control Charge ("SCC") across all electric distribution customers. The SCC provides for recovery of the Company's direct load control program as delineated in Tariff Rider DLC. This charge includes administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT and is assessed on all kWhs delivered to all electric customers

The proposed charges for customers are as follows:

System Control Charge					
	2009	**2010**	**2011**	**2012**	**2013**
($ per kWhr)	$.000055	$0.000127	$0.000168	$0.000199	$0.000223
($ per kWhr) w/SUT	$000059	$0.000136	$0.000180	$0.000213	$0.000239

If approved by the Board, the effect of the proposed changes to the SCC on a residential electric bill is illustrated below. The table below is calculated using the proposed rate for 2013.:

Monthly kWhr Use	Present Bill [1]	Proposed Bill [2]	Increase ($):	Increase (%)
100	$ 17.10	$ 17.11	$ 0.01	0.08%
300	$ 46.26	$ 46.31	$ 0.05	0.11%
500	$ 75.44	$ 75.52	$ 0.08	0.11%
750	$ 110.98	$ 111.11	$ 0.12	0.11%
1000	$ 147.69	$ 147.86	$ 0.17	0.12%
2000	$ 294.51	$ 294.86	$ 0.34	0.12%
2500	$ 367.92	$ 368.35	$ 0.43	0.12%
3000	$ 441.34	$ 441.85	$ 0.51	0.12%

Copies of ACE's August 1, 2008 filing are available for review at the Company's offices (5100 Harding Highway, Mays Landing, N.J.) and at the offices of the Board of Public Utilities (Two Gateway Center, Newark, N.J.).

The following date, time and location for a public hearing have been scheduled so that members of the public may present their views on the above-referenced filing:

Date xx 2008
Time x
Atlantic County Library
Mays Landing, New Jersey 08330

The public is invited to attend and interested persons will be permitted to make a statement of their views. In order to encourage full participation in this opportunity for public comment, please submit any requests for needed accommodations, including interpreters, listening devices or mobility assistance, 48 hours prior to the hearing. Customers may file written comments with the Secretary of the Board of Public Utilities at Two Gateway Center, Newark, New Jersey 07102 Attention: Kristi Izzo, whether or not they attend the public hearings.

Atlantic City Electric Company

SUMMIT BLUE
CONSULTING

NEW JERSEY CENTRAL AIR CONDITIONER CYCLING PROGRAM ASSESSMENT

— *FINAL* REPORT —

Prepared for:

Atlantic City Electric
Jersey Central Power & Light
and Public Service Electric & Gas

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June 4, 2007

ACKNOWLEDGEMENTS

The analysis and recommendations presented in this report are solely the responsibility of the authors though the authors benefited from significant technical input and review from a variety of sources. Staff from Atlantic City Electric, Jersey Central Power & Light, and Public Service Electric and Gas provided critical data on their operations in New Jersey and information on the functioning of and prices in the PJM market. Staff from the EDCs and the New Jersey Board of Public Utilities and Division of Rate Counsel and their consultant provided thoughtful review of key inputs, analysis, and portions of this report during extensive discussions held throughout the course of this project.

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E. Executive Summary

Central air conditioning (AC) direct load control (DLC) programs have been operated by the three electric delivery companies (EDCs) (Public Service Electric and Gas (PSE&G), Jersey Central Power and Light (JCP&L) and Atlantic Electric Company (AEC)) for the past 15 years and have provided reliable load response over this period. While these programs have enrolled approximately 219,000 customers, they are currently not taking new customers, and the infrastructure to administer these programs is dated. Advances in load control and communications technology during recent years have resulted in this being an appropriate time to review current programs and consider upgrades or new program designs.

The objectives of this effort include:

1. Provide cost-effective technology and operational assessments;
2. Develop, recommend and apply a cost-effectiveness methodology for a new, improved, direct load control program that could be operated by each of the EDCs; and,
3. Provide supported recommendations for appropriate strategies for either upgrading the existing infrastructure or complete replacement.

A stakeholder process was used for this effort with weekly progress reports and telephone meetings with key participants. This stakeholder process included the Energy Division of the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel (formerly Rate Payer Advocate). All of these stakeholders were involved with the on-going communications and review of memorandums and interim deliverables.

To complete this assignment, the project was organized into a process comprised of seven steps:

STEP 1: Project Initiation and Scope Review.

STEP 2: Review load control technology and communications capabilities and options for New Jersey.

STEP 3: Review program designs at other utilities and develop option and candidate program approaches for New Jersey.

STEP 4: Develop cost-effectiveness tests for New Jersey, possibly incorporating more than one approach – a simple transparent method along with a more complex forecast-based approach.

STEP 5: Assess the cost-effectiveness of alternative technology and program design options developed in Steps 2 and 3 and using the approaches from Step 4.

STEP 6: Develop recommended technology program design with options as well as assessing the need for decision nodes and flexibility as the program is rolled out to accommodate areas of uncertainty in participation, implementation, electric system conditions and other potential success factors.

STEP 7: This step encompassed the project communications process which consisted of progress reports on each step, a draft final report for comment by stakeholders and a final report incorporating those comments.

E.1 Technology Scenarios

One key step in this process was to look at the many ways AC DLC programs have been delivered, examine different technology options, and develop a set of technology options or "scenarios" that would be examined in greater detail. AC DLC load control programs have combined technologies in many ways in test situations, pilots, and full scale programs. To assess these options, a technology matrix was constructed with common or viable options assessed. Five technology options or "scenarios" representing different combinations of equipment and communication methods were selected from this technology assessment. These five scenarios were examined in more detail and were also examined in the cost-effectiveness models. These five scenarios are shown in the Table E-1.

In this table (and throughout the report) "automated return communication" is defined as data flowing from the thermostat or switch to a central collection point wirelessly or via wires that can be initiated and completed without the need for a person to be physically near each thermostat or switch. Examples include thermostats that send signals through commercial paging systems or communicate with meters that communicate with an Advanced Metering Infrastructure (AMI) system to send data back to the utility. Two of the scenarios (B and D) have no automated return communication in the initial years but automated return communication in later years through an AMI system after it is installed. Of course these scenarios will only be possible if an AMI system is deployed.

With respect to AMI, this report does not take a position on whether AMI is economic. This report is meant to be neutral on that topic. It is believed that the economics of AMI rely on the other (mostly operational) benefits offered, and it would be inappropriate in this assessment to allocate any of the AMI costs (as they run to the meter) to an AC DLC program because any incremental AMI system costs and benefits that an AMI system would provide will be extremely small for this AC DLC program as a fraction of total AMI costs. However, costs clearly incremental to any AMI system such as additional needed communications between the meter and the thermostat or AC switch are included as costs in the technology scenarios and also in the benefit-cost tests. As a result, the AMI costs that run through to the meter are not counted in the technology scenarios, but any additional costs required to go beyond the meter to facilitate the AC DLC program are counted as program costs. Also, any such allocation of base AMI system costs would be essentially arbitrary, not knowing the AMI variant being installed and overall costs of the AMI system.[1]

[1] Several comments received on the draft report indicated that they believed that some portion of the base AMI system costs should be allocated to the AC DLC program. So, there was a difference of opinion on this point. The report states how the AMI costs were treated and readers can take this into account when reviewing the results. In general, no base AMI costs are allocated to the AC DLC program; but incremental costs that would go beyond the AMI buildout to the meter are included (e.g., wireless communications from the meter to the thermostat). In general, the position is taken that for this AC DLC program any allocation of costs and benefits specifically to the base AMI deployment through to the meter would be very small given all that AMI is meant to accomplish.

Table E-1. Technology Scenarios

Scenario	Technology Description
A. Switch with no automated return communication now or in the future	Switch with intelligent cycling; Private radio frequency paging communication
B. Switch with automated return communication through the meter when AMI is in place	Intelligent cycling switch with both private radio frequency paging and an AMI-compatible communications module
C. Thermostat with no automated return communication now or in the future	Programmable thermostat; Private radio frequency paging communication
D. Thermostat with automated return communication through the meter when AMI is in place	Programmable thermostat with both private radio frequency paging and an AMI-compatible communications module
E. Thermostat with current automated return communication capability	Programmable thermostat with commercial paging communication each way (900 MHz range)

Section 3 in the main body of this report presents details on the technology in each of these scenarios as well as a discussion of the benefits and drawbacks or shortcomings of each approach.

E.2 Program Design Review

Thermostats and load control switches have been tested and implemented in DLC programs in a variety of settings throughout the country. These programs were reviewed to summarize program design and technology lessons learned. The study team developed a list of fifty-four programs for review, as summarized in the following table.

Table E-2. AC DLC Programs Reviewed by Type

Type	Number of Programs
Thermostat Programs	6
Thermostat Pilots	12
Switch Programs	32
Combination Switch and Thermostat Programs	4
Total	54

Section 4 of the main report presents the findings from this program design review. This effort helped develop the list of operations and program implementation tasks needed for a successful program. This helped in developing the estimated costs of delivering these programs used in the cost-effectiveness assessment.

E.3 Cost-Effectiveness Inputs for AC DLC Program Assessment

Assessing the cost-effectiveness (C-E) of demand response programs requires the compilation of data from many sources to formulate the best possible assumptions on what the program will be, how many customers will participate, what it will cost and the value of the reductions that may be achieved by the program. Section 5 presents the rationale for the inputs used in the following categories:

- Avoided Capacity Costs

- Control Strategy
- Avoided Energy Costs
- kW Impact per Central Air-Conditioner
- Control Device Equipment Costs
- Customer Incentive
- Participation Rates
- Communication System Costs

The inputs to the cost-effectiveness analyses were incorporated within a spreadsheet to allow for easy testing of alternative assumptions because many of the costs were dependent on other factors, e.g., the estimated number of participants annually impacts the per participant enrollment costs in any one year. This spreadsheet was made available to the EDCs and Stakeholders as an internal project deliverable.

E.4 Cost-Effectiveness Results

Section 6 presents the results of the C-E analysis using two approaches. The first approach is based on a standard spreadsheet model used to calculate the Total Resource Cost (TRC) test and the Rate Payer Impact (RIM) test. The second approach uses the DSMore model available from Integral Analytics, Inc. and used by Duke Power and other utilities for C-E analyses. This model has a market price forecasting module integrated into the analysis that can help examine future prices in PJM and it also has a Monte Carlo capability that allows for the development of high price days.

The results of the TRC benefit-cost assessments for the two methods are shown in Table E-3 below, using the scenarios defined above (and in Section 3).

In general, the DSMore approach produces greater benefit-cost ratios, due to the fact that the DSMore model is able to include the higher benefits of additional load impacts at higher prices during extreme weather events. However, in terms of discriminating between the scenarios, the scenarios were still found to be ranked the same based on the benefit-cost results in both approaches. The fact that both methods produced results that were somewhat similar provides a greater overall level of confidence in the results.

Table E-3. Total Resource Cost (TRC) Test Results

Scenario	MW Impact	Total Resource Cost Benefit/Cost Ratio *(with incentives as transfer payments)*	
		Spreadsheet Model	DSMore Model
(A) Switch with **no change** to automated return communication in the future through AMI	303	1.6 to 2.2	1.5 to 2.2
(B) Switch with automated return communication through the meter when **AMI** is in place	349	2.3 to 3.3	2.5 to 3.7
(C) Thermostat with **no change** to automated return communication in the future through AMI	303	2.0 to 2.9	1.8 to 2.7
(D) Thermostat with automated return communication through the meter when **AMI** is in place	322	4.3 to 6.3	3.6 to 5.3
(E) Thermostat with current automated return communication capability	322	2.9 to 4.2	2.8 to 4.1

Note 1: The ranges show the difference in test results when avoided capacity is valued at $65 per kW per year and $100 per kW per year.
Note 2: Scenarios B and D do not include costs for the AMI system itself.
Source: Analysis by Summit Blue Consulting, May 2007

Scenario D, thermostats with AMI, has the highest TRC test score. This is largely due to the fact that the maintenance costs decline and the achieved impacts rise when AMI starts. As with the other thermostat scenarios, the thermostat itself is part of the incentive to the participant. The purchase and installation costs for the thermostats are netted out of the equation from the societal perspective, and these are significant program costs.

The other thermostat programs would also be expected to have high TRC test scores for the same reason. They are also high, but tempered by other significant costs. Scenario C, thermostats with no AMI, has high costs for a manual inspection program. Scenario E, the thermostat with current automated return communication capability, has the highest device purchase and installation costs of all the scenarios, plus high on-going communication system costs.

Scenario B, switches with AMI, has a relatively high TRC test score even though all purchase and installation costs for the switches are included. However, the annual incentive payments are excluded.

E.5 AC DLC Program Design Recommendations

Recommendations were developed for a central AC DLC program that could be rolled out at scale in 2008. Five themes ran through these recommendations:

THEME 1: Proven Technology and Program Concepts. One goal is to develop a program that can have measured steps in marketing, implementation and roll-out that will result in a program that can be delivered at scale next summer, i.e., in 2008. The recommendations call for a five-year implementation plan resulting in a target of 17% penetration of the program among residential customers with central AC, and an additional increment of small business customers that can use the same technology. The target number of new device installations is shown in Table E-4. This rollout would attain the targets of new installations through a migration of current AC DLC program participants to the new program as well as seeking new participants. The first-year rate accounts for a ramp up of activities, given that only half a year of time will be available for recruiting and equipment installation. Even given this first year ramp up, this represents an aggressive schedule, particularly for the early years of the program when design assumptions are being validated through ongoing customer research. This schedule requires that the technologies that form the basis of the program be proven and ready for immediate application without foreclosing future options that might improve the programs as the technologies continue to advance. The rate of converting existing participants from the legacy program to the new program was assumed to be constant after the first year. As the factors that influence customer sign-up will vary from year-to-year, these are not meant to be exact goals but target mileposts that could be exceeded or fall a bit short. These mileposts are designed to help ensure the five-year participation goal is met, with some variation in the year-to-year new participation milestones. In fact, it is expected that the EDCs may vary from this projected year-to-year participation as they fine tune their marketing efforts and field work to meet the five year goal and make significant contributions to that goal on an annual basis.

Table E-4. Program Participation in the New AC DLC by Program Year

	2008	2009	2010	2011	2012
Transfer Legacy Participants[2]	27,000	48,000	48,000	48,000	48,000
New Participants	4,000	14,000	14,000	14,000	14,000
Total Participants Added	31,000	61,000	61,000	61,000	61,000
Cumulative Participants	31,000	92,000	153,000	214,000	275,000

<u>THEME 2: Switch Program Maintenance Costs</u>. Without AMI or automated return communication, it is impossible to know if a switch is operating properly without physically examining each switch on-site on a regular basis. Without an aggressive inspection and maintenance program, the reliable demand impacts of a switch program decline significantly over time. As a result, to implement a viable program, the significant costs of an aggressive inspection and maintenance process need to be incorporated into the program costs.

<u>THEME 3: Benefits of Thermostat Technologies for both Utilities and Ratepayers</u>. Thermostats provide additional benefits to participants compared to switches and can support other program options, such as time-of-use (TOU) rates and real-time-pricing.

<u>THEME 4: Rapidly Evolving Communication Technologies</u>. Communication technologies for AMI, for communication between switches and thermostats and AMI systems, and for AMI-independent communication between thermostats and utilities are evolving rapidly. It is not yet possible to reliably predict which communication approaches will prove to be most stable, useful, and accepted by the market. As a result, it is too soon to specify the best approach for automated return communication from thermostats or switches to utilities. The DLC program design and technology specification should be flexible to enable the EDCs to track changes in the development of technology and the maturation of the market so that they can easily adopt their DLC program to the communications platform they select.

<u>THEME 5: Flexibility to Upgrade the Program Technologies and Design</u>. Designing a program that provides the best solution for New Jersey requires adapting approaches as the market changes and as utility knowledge of the market increases. As a result, the most effective approach to a DLC is one that preserves a generous amount of flexibility. Both thermostats and switches present significant benefits for program implementation, and they may appeal to different segments of the market. Thus a program that supports both technologies can capture the largest share of the market most cost-effectively. Solutions for automated return communication from thermostats and switches are undergoing rapid evolution and no

[2] There are approximately 219,000 participants in the current program, labeled "Legacy Participants". Over time they will all be transitioned over to the new program.

clear winner has appeared. Therefore, a technology approach that is designed to adapt when a winner becomes clear can provide a load control solution that will remain viable and effective well into the future. Finally, it is impossible to know exactly how the New Jersey electric utility customers will react to program designs and to load control events. To adapt to customer information as it is developed and at the same time maximize the demand savings achievable from the program, it is important to provide significant flexibility to program implementers on the details of control strategies while planning for significant research into customer reactions.

E.6 Summary of Program Design Recommendations

Section 7 of the main report presents the list of recommendations across eight high level program design and technology categories. A summary of key components of these recommendations that flow from the five themes is presented below:

Equipment. The program should offer customers a choice between switches and thermostats. The current radio system should be used for sending out control signals to both switches and thermostats. The EDCs should not initially require that the system have built-in automated return communication capability. The EDCs should require that the devices can eventually be retrofitted with automated return communication capability without replacing the entire device. The EDCs should have rights to the communications protocol and to head-end software and controls platforms so they can use the system with equipment from other vendors in the future. In their RFPs sent to potential vendors, the EDCs should specify the equipment features they believe are critical and ask for the vendor's approach to dealing with other issues. Because the technology is rapidly evolving, this approach will specify minimum criteria but allow the vendors latitude for creatively addressing the EDCs' needs.

Cycling and Ramping Strategy. The EDCs should test a variety of cycling and ramping strategies to determine the strategies that best serve their needs in a variety of scenarios. The impact of these strategies should be tested for the New Jersey program as the program is being rolled out. These test strategies should measure total load response, the duration of load response, and participant reactions and satisfaction.

Event Criteria. The report makes an aggressive recommendation in the number of events that can be called and the number of hours per event. This is meant to allow the program to be available when additional reliability is needed on the system. It is not expected that the full number of events will be called nor the full event period be called, except during very rare circumstances. Given this, it is recommended that the EDCs should set a limit on the number of events per summer to 20. They should set no maximum hours per day that can be under control. They should set no maximum number of days in a row control can be called. As a general rule, the EDCs should call control events when the day-ahead market predicts greater than $250/MWh and weather conditions are right.

Program Incentives. For switches, the New Jersey EDCs should maintain their current incentives ($4 per month plus $1 per event for PSE&G and JCP&L, $1.50 per month plus $1.50 per event for ACE) to minimize disruption and confusion for current participants. For thermostats, the EDCs should provide and install the thermostat for free and provide a $50 signing bonus for new customers (including new occupants in a home with a program thermostat installed). The EDCs should monitor their success in marketing the program and modify the signing bonus as needed to manage their sign-up rate.

Customer Eligibility. Participants must have a central AC system or electric heat pump. They must own and live in the home (Owner-Occupied). If a home has more than one central AC unit and has elected to get a switch, each AC unit must receive a switch. Each unit receives an incentive. If a home has more than one AC unit and has one thermostat that controls both compressors, they will be eligible for one thermostat and one incentive. If each thermostat controls its own compressor, they are eligible for one thermostat and one incentive per compressor. All thermostats must be controlled. Small commercial customers whose AC equipment can be matched to the curtailment technology should be eligible for the program when processes and standards are ready. Each utility should define the size of commercial customer eligible to participate to match its own unique population.

Maintenance and Monitoring & Verification. Demand response (DR) programs are becoming viewed as resources by more utilities and reliability organizations. Just as a power plant needs maintenance, a DR program such as the AC DLC proposed here needs maintenance and measurement of the load delivered. Key components of the maintenance and measurement and verification (M&V) related recommendations include:

- Prior to some method of automated return communication, to determine if the control devices are operating correctly, the EDCs should go on-site to each participant's site to check for the existence and correct operation of the device. Each device should be visited at least once every five years, and synergies with other customer contact programs should be utilized to lower the costs of this activity. These synergies might occur with energy efficiency program participants.
- Yearly independent impact assessments should be implemented using a sample of participants with interval meters or compressor run-time logger data. A single impact assessment should be implemented to cover all New Jersey central air-conditioning DLC programs.
- After some method for automated return communication is established, each utility should develop procedures to test each control device remotely. The system should send control signals to shut down the AC then use the meter data to look for evidence of a change in usage that corresponds to shutting off the AC.[3] Such a test should be run on each device at least once a year.
- With some mechanism for automated return communication, data should be collected from each thermostat and switch after each event to support calculating impacts and verifying device status.

Program Roll-out and Customer Research. The final pages of Section 7 provide a suggested schedule for designing and rolling out the program. A Request for Proposal (RFP) should be sent to potential vendors by September or October 2007 to ensure time for ordering equipment. Customer recruiting ought to begin by January 2008 and installations by February 2008 in order to be ready to begin the active program in July 2008. It will be important to have a customer research program in place to test how participants are responding to incentives and to make any mid-course corrections needed in program operations.

[3] The length of the shut off need only be long enough to ensure that its effects are visible in the meter data.

1. BACKGROUND

New Jersey EDCs have delivered load control programs focused on central air conditioning for the past 15 years. While these programs have enrolled approximately 219,000 customers, they are currently not taking new customers, and the infrastructure to administer these programs is dated. Advances in load control and communications technology during recent years have rendered much of the existing equipment obsolete, or at least in need of an upgrade and make this an appropriate time to review current programs and consider upgrades or new program designs.

The objectives of this effort include:

1. Provide cost-effective technology and operational assessments;
2. Develop, recommend and apply a cost-effectiveness methodology for a new, improved, direct load control program that could be operated by each of the EDCs; and,
3. Provide supported recommendations for appropriate strategies for either upgrading the existing infrastructure or complete replacement.

This report addresses these assignment objectives.

A stakeholder process was used for this effort with weekly progress reports and telephone meetings with key participants. This stakeholder process included the Energy Division of the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel (formerly Rate Payer Advocate). All of these stakeholders were involved with the on-going communications and review of memorandums and interim deliverables. While a stakeholder process was used, there were differences of opinion on some issues and the report worked to take into account the different positions expressed by the parties through sensitivity analysis and by stating the assumptions that underlie the assessment.

The next section discusses the approach taken to complete this assignment and prepare this report. Section 3 presents details on the technology in each of the scenarios examined as well as a discussion of the benefits and drawbacks or shortcomings of each approach. Section 4 presents the findings from the program design review. Section 5 discusses the assumptions and calculations made to create the inputs to the cost-effectiveness analysis. Section 6 presents the results of the C-E analysis. Section 7 presents the list of recommendations across eight high level program design and technology categories. Appendices to the report include details on inputs for cost-effectiveness scenarios: Appendix A: Details on Inputs for Cost-effectiveness Scenarios; Appendix B: Communications Technology Guide; Appendix C: Detail on New Jersey Residential Air Conditioning Load Curves Developed for the DSMore Model; andAppendix D: Bibliography.

2. APPROACH TO ASSIGNMENT

This assignment was organized into a number of process steps. These steps are listed below with a more complete description of each step presented in separate sections.

STEP 1:	Project Initiation and Scope Review.
STEP 2:	Review load control technology and communications capabilities and options for New Jersey.
STEP 3:	Review program designs at other utilities and develop option and candidate program approaches for New Jersey.
STEP 4:	Develop cost-effectiveness tests for New Jersey, possibly incorporating more than one approach – a simple transparent method along with a more complex forecast-based approach.
STEP 5:	Assess the cost-effectiveness of alternative technology and program design options developed in Steps 2 and 3 and using the approaches from Step 4.
STEP 6:	Develop recommended technology program design with options as well as assessing the need for decision nodes and flexibility as the program is rolled out to accommodate areas of uncertainty in participation, implementation, electric system conditions and other potential success factors.
STEP 7:	This involves project communications which consisted of progress reports on each step, a draft final report for comment by stakeholders and a final report incorporating those comments.

The sections below briefly discuss these assignment steps.

2.1 Step 1: Project Initiation and Scope Review

An initial meeting was held at PSE&G's Headquarters in Newark on February 9, 2007. Prior to the meeting, available program documents were reviewed and an agenda was developed in conjunction with the project management team.

This initial meeting resulted in the following decisions:

- Hold a conference call each week to review project progress, discuss issues, and make necessary decisions.
- Provide information on the DSMore cost-effectiveness model to the EDCs, BPU, and Rate Counsel Staff.
- Develop a contact list for project communications.
- A schedule modification was to be developed by the EDCs related to their filing deadline so this assignment can be used to better inform the EDCs filings. This is to account for the fact that a broad program rollout will not happen until after the summer of 2007.

Broad direction issues that arose at the initiation meeting included:

- The conservation benefit of thermostats should be included in the cost-effectiveness calculations.

- The criteria for technology selection should include a judgment as to whether individual control technologies have been successfully deployed in the field and the extent of that deployment.
- The program design needs to address how existing, legacy participants are to be handled.
- The study should create a single program recommendation but distinguish between core and supplemental or add-on features.
- The cost-effectiveness analysis will primarily examine system benefits and will not venture far into examining other, more hard-to-quantify benefits.
- The cost-effectiveness analysis will try to examine the potential impact of the program on congested transmission nodes but will not examine all possible nodes.

This meeting produced a memo addressing the assignment scope and activities. This was provided for review to the stakeholder group based on the outcomes of the project initiation and scoping meeting.

2.2 Step 2: Review Control and Communications Technologies

This task involved the review of available options in the market for load control technology with a variety of features and cost ranges, with a focus on thermostat-based systems.

Some of the criteria included in this review that can impact technology selection and subsequently developing specifications for vendor bids are:

- Cost – the all-in cost of technology, installation, software, operations and evaluation
- Customer-friendly interface and simplicity of use
- Internet access to allow for remote programming
- Capability with current or planned communications technology (power line carrier, radio communications, pager system, etc.)
- Support for technology and software
- Ability to upgrade systems and software

Emphasis was placed on technologies likely to be compatible across all EDCs in the state. This technology review was tied to the program review by assessing the effectiveness of the hardware and software employed across the range of programs reviewed in Step 3. This review involved research into the specified features and costs of technologies available from a number of vendors in the market today. In addition, a number of secondary sources were examined as well.[4] The review worked to assess lessons learned regarding technology applications at other utilities and in other jurisdictions.

A memorandum summarizing the review of load control technologies against a set of criteria[5] established early in the project was drafted and agreed upon by all parties. The memo formed the basis for section 3 of this report.

[4] Sources of secondary data include ESource reports completed during Mr. Cooney's tenure as leader of the research group there, including; *Two-way thermostats Creating New Markets for Residential Load Control Programs*, ER-02-4, and *Information and Communication Elements of Peak Load Management Programs*, EIC-19, July 2002. Both of these efforts cited Dr. Violette's work, and Summit Blue is also familiar with some of the recently updated research conducted by ESource on the topic. Additional secondary information is available from a variety of websites and conference presentations, including those from the major thermostat and control device manufacturers, and presentations made at the Peak Load Management Alliance (PLMA) conferences and AESP Technology Fairs.

[5] These criteria constituted a separate memo and were discussed at one of the project conference calls.

2.3 Step 3: Review Program Designs

This step was comprised of a review of AC DLC programs, an assessment of lessons learned, and organization of this information within the situation in New Jersey to allow for appropriate program options to be developed.

2.3.1 Review Program Designs from Around the Country

A literature search was conducted and supplemented by interviews with program managers to identify approaches being practiced or proposed for AC load control programs. Based on this research, a matrix was prepared for internal use[6] that summarized the following program attributes:

- Utility and program name
- Years program offered
- Technology used to initiate control (e.g., thermostat, receiver on compressor)
- Communication method (e.g., paging, internet, radio frequency)
- Target customers and customer eligibility requirements
- Load control strategies, timing, duration (hours per event and total hours per year), and tiers
- Curtailment parameters (e.g., allowable number of curtailment hours and events, historical number of curtailment hours and events)
- Over-ride rules and methods (e.g., on-site override, phone override, Internet override)
- Incentives and penalties
- Participation (number of customers by sector, penetration rate, dropout rate)
- Level of satisfaction with load control program
- Load reduction achieved

This matrix provides input into the design of options considered for New Jersey, but each option needs to stand on its own merits in the context of the situation in New Jersey.

2.3.2 Assess Lessons Learned

Using information from the program review, lessons learned regarding programs and strategies in other jurisdictions were assessed. These were then considered in the context of the situation in New Jersey to help inform the development of candidate options.

2.3.3 Develop Candidate Program Options

Knowledge of the New Jersey utility's service areas and markets will be combined with the information from the reviews and lessons learned to define the AC load control approaches that are the candidates for use as part of a comprehensive AC cycling program in New Jersey. Based on this assessment, and input from the stakeholders, a recommended program design will be developed. The design addresses:

- Technology used to initiate control (e.g., thermostat, receiver on compressor)

[6] Some information was not formally documented by the utility or vendor (or possibly yet approved by regulators) and a request was made to keep some information confidential. The matrix was reviewed by the stakeholders, but is not a public document.

- Communication method (e.g., paging, internet, radio frequency)
- Curtailment parameters (e.g., allowable number of curtailment hours and events)
- Target customers and customer eligibility requirements
- Load control strategies, timing, duration (hours per event and total hours per year), and tiers
- Over-ride rules and methods (e.g., on-site override, phone override, Internet override)
- Incentives and penalties
- Estimated participation levels (number of customers by sector)
- Evaluation strategy including impact analysis, follow-up and satisfaction surveys

Internal project memos were prepared discussing these program criteria, summarizing AC load control programs from around the country and drawing out elements that might serve as building blocks for the program designs to be assessed in the cost-effectiveness analysis.

2.4 Step 4: Cost-Effectiveness Approaches

This step involved examining cost-effectiveness frameworks used in other jurisdictions and applying those frameworks to the candidate options that came out of the technology and program review efforts. The focus of this effort is on comparing different AC DLC program designs that might replace the current programs. As a result, the C-E frameworks need to be able to both assess overall benefits and costs, but also be able to assess pivot factors that make one type of approach preferred to another approach, i.e., there is a need to be able to differentiate across alternative program designs. The approach selected for this effort was to dimension the benefits and costs using two approaches – 1) a simple, transparent spreadsheet model focused on the TRC test and directed at identified resource savings rather than indirect benefits that might come from these programs; and 2) a more sophisticated hourly method that embodied forecasting of hourly PJM prices in the calculation of benefits and costs. This second method made use of the DSMore cost-effectiveness method used by several utilities and offered through Integral Analytics.[7]

2.5 Step 5: Application of C-E Approaches to Candidate Program Options

The two approaches from Step 4 were used to assess AC Cycling or Load Control Programs, and perform sensitivity analysis based on different levels of participation up to a maximum market penetration of 50% of the AC load. This effort included the development of the required input data – both benefits and program costs – identification of on-going data sources and development of the test schematics. As agreed in the project status conference call on February 20, 2007, we will use the DSMore model will be used and the results compared to those obtained through a spreadsheet model.

The end product of this effort is the assessment of benefits and costs of the alternative candidate program designs.

[7] This was agreed upon during the project status conference call on February 20, 2007 where the DSMore model would be applied with thee results compared to those obtained through a spreadsheet model.

2.6 Step 6: Develop Recommendations

This step involves the development of a recommended approach to pursuing residential and small commercial direct load control of central air conditioners in New Jersey. The recommendation is organized into areas that influenced the program design. Within these areas, the program or equipment features believed important and those believed useful, but not absolutely required, are discussed. It is recommended that the EDCs issue RFPs to vendors of appropriate equipment, specifying the important features as required and asking for their best approach that also may take into account the useful, but not necessary features. These different elements of the recommendation are supported by a short rationale statement with the material in the preceding sections providing more information on these program elements.

2.7 Step 7: Communications — Progress Reports, Draft and Final Reports

There was an expectation at the outset of this project that the time frame for this project required frequent communications to move forward at a rapid pace. This consisted of weekly project phone meetings and interim memos on key topics. Internal memos produced included:

- Memo recommending load control technology and communications capability.
- Memo on program design criteria and ideation.
- Several memos addressing on-going cost-effectiveness analyses and work on different program designs as information became available (e.g., the April PJM capacity auction) and additional information was compiled on program costs, which was developed by the project team and EDCs up through the final runs of the C-E models.
- The Draft Final report with time for comments was prepared and comments will be incorporated into the final report.

3. TECHNOLOGY OVERVIEW

Selecting the best approach for AC load control in New Jersey involves technology decisions in two areas, the control mechanism and the communication method.

There are two options for a control mechanism: 1) A switch, which upon receiving a signal interrupts the power to the compressor at the compressor or at the fuse box; and 2) A thermostat that controls the operation of the AC by adjusting the temperature set point or turning the compressor off and on. Switches can be attached to other non-plug, electric loads such as electric water heaters or pool pumps.[8]

The communication method determines how the signal to start and end a control event gets from the utility to the device (whether switch or thermostat) and how data flows back from the devices to the utility. Communication methods can be divided into three categories. 1) Wireless, 2) Wired, and 3) Manual. Some systems use combinations of each of these methods. Each method is discussed in more detail below.

1. Wireless. Wireless communication involves some kind of radio signal. Radio signals are sent out from AM/FM radio towers, through paging system towers, or through satellite paging systems. Some communities are building publicly available WiFi or WiMax broadband Internet communications systems. The New Jersey EDCs already own some radio towers, used for communication with field staff as well as for the legacy load control system. Other options include leasing bandwidth on towers owned by someone else and using commercial paging providers. Wireless communication can include signals sent from the utility to the device and vice versa. The most common approach used in the past for sending return data electronically is through commercial two-way paging systems, which are designed to capture return signals.

2. Wired. Wired systems use signals sent over power lines (e.g., power line carrier or broad band over power line), through always-on Internet wiring (cable or DSL), or through a land-line telephone (not through cellphone or Internet phone (VOIP)). The first two systems fully support outbound and return communication. Non-DSL telephone lines are typically only used for return communication from load control equipment to the utility, not for signals from the utility to the load control equipment. The devices will call the utility load control system to deliver data, typically in the middle of the night. They will hang up to avoid blocking outbound personal calls if they detect that a hand-set has been picked up. They are not designed to answer the phone, as they are usually sharing the participant's regular phone line and inbound calls would ring at the participant's regular phone.

3. Manual. As used in this report, the term "Manual communication" means a person going physically near each thermostat or switch to collect data. In the past, "Near" has meant close enough to touch the device. Vendors claim that for some new technology, "Near" could mean the street adjacent to a participant's house. Manual communication is only relevant for returning data from the load control switch or thermostat to the utility.

Some vendors insist that the phrase "two-way communication" can encompass systems that use people as the transport mechanism for the electronic data returning from the switch or thermostat to a central repository of data. To support maintenance and estimating impacts, it is critical that some system be used

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[8] Some thermostats and switches can communicate with each other so the thermostat can signal the switch to turn off non-plug electric loads.

to verify signal receipt, control behavior, and demand savings, no matter what the transport mechanism for the electronic data. As a result, this definition of "two-way communication" is not particularly useful for this report as any viable technology must allow for some kind of return data. However, to be perfectly clear this report will specify the transport mechanism for outbound control signals and the return of data from thermostats and switches and will avoid using the phrase "two-way communication".

To shorten and simplify some sentences, this report will occasionally use the following terms.

- **Automated return communication:** Defined as data flowing from the thermostat or switch to a central collection point wirelessly or via wires that can be initiated and completed without the need for a person to be physically near each thermostat or switch. Examples include thermostats that send signals through commercial paging systems or communicate with Advanced Metering Infrastructure (AMI) meters to send data back to the utility.

- **Manual return communication:** Defined as data flowing from the thermostat or switch via people collecting it one site at a time while being physically near each thermostat or switch. Examples include downloading data from the thermostat by connecting a personal digital assistant (PDA) to it, reading lights on a switch from outside the house, or using a ZigBee device to download data from the thermostat or switch while near the house. (The first two of these examples have been implemented for years. The ZigBee approach is new and relatively untested).

Hybrid. Some load control systems use a combination of these communication methods. Options include (but are not limited to) the following:

- Wireless outbound control signal with telephone return data;
- Wireless outbound control signal with manual return data (typically based on a sample); and
- Wired power line carrier outbound and return signals sent via an AMI system to the meter with wireless two-way communication between the meter and the thermostat.

A note about cycling control approaches. Cycling strategies can be implemented on a strict time-based approach, e.g., 15-minutes on and 15 minutes off for everyone, or with some newer switches and thermostats, by adjusting the on/off cycles to take into account historical run time data. For example, if an AC unit is oversized and only runs for 20 minutes every half hour on hot days, with this approach the control device recognizes that and cuts the run time to 10 minutes when a 50% duty cycle is called. This capability is marketed as "TrueCycle by Cannon and "Adaptive Algorithm" by Comverge and is referred to as "**intelligent cycling**" in this report.

3.1 Technology Scenarios

The technology options discussed above have been combined in many ways in test situations, pilots, and full scale programs. Each of the most common or viable options was examined and then five scenarios or combinations of equipment and communication methods were defined that present the most appropriate and realistic choices for residential and small commercial load control in New Jersey. These five scenarios were examined in more detail and were run through the cost-effectiveness models. These five scenarios are shown in the following table. Two of the scenarios (B and D) have no automated return communication in the initial years but automated return communication in later years through an AMI system after it is installed. Of course these scenarios will only be possible if an AMI system is deployed. This report does not address whether AMI will be deployed nor on what timeline.

Table 3-1. Technology Scenarios

Scenario	Technology Description
A. Switch with no automated return communication now or in the future	Switch with intelligent cycling; Private radio frequency paging communication
B. Switch with automated return communication through the meter when AMI is in place	Intelligent cycling switch with both private radio frequency paging and an AMI-compatible communications module
C. Thermostat with no automated return communication now or in the future	Programmable thermostat; Private radio frequency paging communication
D. Thermostat with automated return communication through the meter when AMI is in place	Programmable thermostat with both private radio frequency paging and an AMI-compatible communications module
E. Thermostat with current automated return communication capability	Programmable thermostat with commercial paging communication each way (900 MHz range)

The following sections present the top level elements that comprise each technology scenario and an initial listing of the high level pros and cons of each scenario. Following that is a summary discussion of other options examined.

3.1.1 Scenario A: Switch with No Automated Return Communication Now or in the Future

SCENARIO A: Switch With No Automated Return Communication	
Description: • Switch on or near the AC compressor to provide cycling control • VHF paging one-way communication (no automated return communication) • Intelligent cycling	
Pros: • Known, established equipment • Inexpensive to install • Override capability available, but requires customer action beyond adjusting a thermostat setting • Intelligent cycling improves impacts and produces equivalent reduction from all participants	Cons: • No feedback on status or impacts • Expensive to maintain throughout the life of the project

This scenario is most like the current programs offered by the New Jersey EDCs. Switches are placed outside on or near the compressors. They receive control signals from the VHF paging system currently used by the New Jersey EDCs for load control and for communication with field staff. Upon receipt of a control signal, the switch cycles the compressor on and off on a fixed schedule, as defined by the instructions received in the signal. This scenario assumes that existing switches will be replaced by new switches over time as the EDCs perform on-site M&V work. This scenario assumes that each switch is visited once very five years. The new switches have the same features as the old ones with one exception – the new switches can do intelligent cycling. This scenario assumes that the switch will never be configured to return electronic information automatically to the utility, whether through an AMI system or through some other electronic automated return communication approach.

This approach uses known, well established equipment. It is relatively inexpensive to install as the equipment is generally cheaper than thermostats and installers do not need to make appointments to enter customer homes, which shortens the amount of time needed to install. Customers must make a call to the utility or use a web site to override, which generally produces fewer overrides. Due to the fact that the switch is outside and generally in an out-of-the way location, it is less likely that the customer will notice that a control period is underway than with a thermostat. Intelligent cycling increases the impacts gained from those with over-sized ACs, and it improves the fairness of the program by extracting savings equally from all participants, instead of controlling those with undersized or right-sized equipment more than those with oversized equipment.

This approach provides no automated approach to providing feedback on the status of the device or data for estimating impacts. To collect data from the device requires a manual operation at each switch. Because there is no way to determine if a switch is operating correctly without going physically near it, each and every switch must be visited on a regular basis to maintain the system. This creates a significant expense that must be incurred on an ongoing basis throughout the life of the project. In some cases due to communications problems, switches may actually be operational but do not receive a signal for a particular event. Without automated return communication, the utility cannot know if each switch is only receiving a signal part of the time. M&V procedures based on samples can produce an estimate of the percent of switches that do not receive signals.

Switches, particularly with intelligent cycling, provide relatively predictable load control results, but they do not provide the same level of flexibility as communicating, programmable thermostats do, which can do cycling as well as temperature setback and ramping. Switches can be used to support a critical peak pricing (CPP) rate but provide fewer options for participants to help them control their electricity use under TOU and CPP rates or other innovative rate structures.

3.1.2 Scenario B: Switch with Automated Return Communication through the Meter when AMI is in Place

Scenario B: Switch with Automated Return Communication through the Meter when AMI is in Place	
Description: • Switch on or near the AC compressor to provide cycling control • VHF paging one-way communication (no automated return communication) until AMI is in place then automated return communication through the AMI • Intelligent cycling	
Pros: • Known, established equipment • Inexpensive to install in the beginning • There will be declining maintenance costs for this system once AMI is in place	Cons: • Expensive to maintain until AMI is in place. • Possible expense to swap out communications boards when AMI installed • No feedback on status or impacts until AMI is installed

This scenario is identical to Scenario A with one significant difference. This scenario assumes that AMI is installed within 5 years and that the AMI system provides a means for electronically returning data from the switch to the utility (without the need for on-site visits to each switch). Note that this report does not predict that AMI will be deployed; this is only a scenario assumption in order to examine the complete range of possibilities. This report does not take a position on whether AMI is economic. It is meant to be neutral on that topic. It is believed that the economics of AMI rely on the other (mostly operational) benefits offered and that it would be inappropriate in this assessment to allocate any of the AMI costs (as they run to the meter) to an AC DLC program as any incremental AMI system costs and benefits that an AMI system would provide will be extremely small for this AC DLC program as a fraction of total AMI costs. However, costs clearly incremental to any AMI system, such as additional needed communications between the meter and the thermostat or AC switch, are included as costs in the technology scenarios and also in the benefit-cost tests. As a result, the AMI costs that run though to the meter are not counted in the this scenario (or other scenarios that include AMI), but any additional costs required to go beyond the meter to facilitate the AC DLC program are counted as program costs. Also, any such allocation of base AMI system costs would be essentially arbitrary not knowing the AMI variant being installed and overall costs of the AMI system.

In this scenario, after AMI is in place, the existing radio infrastructure would continue to be used to send out control signals to switches as it can do so cost-effectively and is well suited to rapidly sending signals out to thousands of switches. The switches will communicate with the AMI system through some kind of wireless protocol, whether that is ZigBee or one of the other protocols being tested in the market. At this point in time it is not clear which wireless protocol will be most appropriate as the standards and technology are still undergoing rapid evolution. However, this scenario assumes that some wireless protocol will emerge to provide reliable communication between the AMI system and the switch. At least two vendors claim to have switches that will communicate with AMI systems.

Automated return communication through the AMI system will reduce the significant maintenance costs associated with finding failed or missing switches. The automated return communication will enable program managers to identify with a reasonably high level of certainty those switches that are no longer operating correctly. The program will then no longer need to do on-site inspections for all switches on a regular basis. It will do on-site inspections when the return communication system indicates there is trouble with a specific switch. In addition to reducing maintenance costs, the automated return communication will increase the reliability of the estimated demand savings produced by the system, enabling the program to support a claim for a higher level of savings.

Enabling communication through an AMI system would involve an extra expense to swap out the switch's communications boards when AMI is installed. Switch vendors claim that this swap-out can be done quickly and without changing the entire switch. It is also possible that the EDCs could procure switches that already have hardware built-in for communicating with AMI systems. However, that will entail extra costs up front and assumes that any purchase made for the 2008 control season will incorporate a communications system that is stable and appropriate for the long term.

In the cost-effectiveness analysis, it is assumed that the costs for the AMI system are not borne by the load control program but the benefits of reduced maintenance costs and improved impacts do accrue to the load control program.

3.1.3 Scenario C: Thermostat with No Automated Return Communication Now or in the Future

<table>
<tr><td colspan="2">Scenario C: Thermostat with No Automated Return Communication Now or in the Future</td></tr>
<tr><td colspan="2">Description:
• Communicating programmable thermostat that can implement AC cycling, temperature setback, and temperature ramping load control strategies
• VHF paging one-way communication (no automated return communication)
• Intelligent cycling</td></tr>
<tr><td>Pros:
• Reasonably well tested hardware
• Offers pre-cooling and temperature setback options
• Lower operating expense if no monthly or event fees to customers
• Provides customer a free gadget and tool to manage energy use</td><td>Cons:
• No feedback on status or impacts
• Expensive to maintain
• Ease of over-ride with some thermostats</td></tr>
</table>

Under this scenario, the program installs a free communicating programmable thermostat. This scenario assumes that existing switches will be replaced by new thermostats over a five year time frame (see timeline in Section 7 – Recommendations) and new participants would be given thermostats. The thermostats receive control signals from the same VHF paging system currently used by the New Jersey EDCs for load control and for communication with field staff. Upon receipt of a control signal, the thermostat can operate like a switch and cycle the compressor on and off on a fixed schedule, as defined by the instructions received in the signal. The thermostat can also implement control strategies based on changing the thermostat set point. For example, the thermostat could increase the temperature set point by 2 degrees each hour for 3 hours. During the beginning part of each hour, the compressor would likely not run while the house temperature gradually rises the 2 degrees. Upon reaching the new setpoint, the thermostat will cycle the compressor as it normally does to keep the home at the new setpoint. As with the switch scenarios discussed above, the thermostats discussed in this scenario can do intelligent cycling.

This scenario assumes that the thermostat will never be configured to return electronic information automatically to the utility, whether through an AMI system or through some other electronic automated return communication approach.

Some thermostats on the market allow participants to over-ride control by pushing a button on the thermostat. This gives participants easier control over their system but tends to result in significantly higher over-ride rates. Some over-rides occur unintentionally when participants do not realize a control period is underway when they change their temperature. This scenario and the cost-effectiveness analysis assumes that the thermostat does <u>not</u> allow override at the thermostat. Customers must make a call to the utility or use a web site to override.

Intelligent cycling increases the impacts gained from those with over-sized ACs and it improves the fairness of the program by extracting savings equally from all participants, instead of controlling those with undersized or right-sized equipment more than those with oversized equipment.

Because the thermostat is inside, it is more likely that the customer will notice that a control period is underway than with a switch. However, the thermostat is less subject to hardware failure because of weather. Both switches and thermostats can be inadvertently removed if a participant buys a new AC and the HVAC contractor does not know or care that the device is necessary for the load control program.

It is more expensive to install thermostats than switches as the equipment is generally more expensive and installers must make appointments to enter customer homes, which lengthens the amount of time needed to install. However, thermostat programs typically do not include a monthly or event fee to participants, which reduces program expenses. (No monthly or event fee was assumed for this scenario in the cost-effectiveness analysis.)

As with Scenario A, this approach provides no automated approach to providing feedback on the status of the device or data for estimating impacts. To collect data from the device requires a manual operation at each device. In the past, thermostats required direct connections to download their data (typically using a PDA). Vendors claim that some thermostats now available could use short-range wireless communication (e.g., ZigBee) to download data to a reader outside the house but relatively nearby (within 100 feet or less).

If a thermostat fails to operate at all, participants will likely call the utility to report the problem (although some may elect to call an HVAC company or replace the thermostat themselves). If the thermostat operates normally but no longer receives or reacts to the control signal, it is likely the participant will not notice and report that fact. Even though some problems will be reported by participants, there is no way to determine if a thermostat is operating correctly without going physically near it, thus each and every thermostat must be visited on a regular basis to maintain the system. This creates a significant expense that must be incurred on an ongoing basis throughout the life of the project.[9] In some cases due to communications problems, thermostats may actually be operational but do not receive a signal for a particular event. Without automated return communication, the utility cannot know if each thermostat is only receiving a signal part of the time. M&V procedures based on samples can produce an estimate of the percent of thermostats that do not receive signals.

Thermostats offer the same cycling advantages as switches and thus can provide relatively predictable load control results. In addition, they provide increased flexibility to the program by enabling temperature setback and ramping options. Thermostats can be used to pre-cool a house before a control period to reduce participant discomfort during a control event. Thermostats can be used to support a CPP rate and provide a free tool for participants to control their electricity use under TOU and CPP rates or other innovative rate structures.

[9] Another approach that has been suggested is to test the thermostats by calling the customer, if they answer send a signal to their thermostat, ask them if the control symbol or words on the thermostat is lit, send a cancel control signal to the thermostat and then ask the customer if the control symbol is now off. We are not aware that this has ever been tried, but it might be cheaper than sending people on-site. It also may be problematic to reach enough people by phone for this to be a meaningful test.

3.1.4 Scenario D: Thermostat with Automated Return Communication through the Meter when AMI is in Place

Scenario D: Thermostat with Automated Return Communication through the Meter when AMI is in Place	
Description: • Communicating programmable thermostat that can implement AC cycling, temperature setback, and temperature ramping load control strategies • VHF paging one-way communication (no automated return communication) until AMI is in place then automated return communication through the AMI • Intelligent cycling	
Pros: • Reasonably well tested hardware • Offers pre-cooling and temperature setback options • Lower operating expense if no monthly or event fees to customers • Provides customer a free gadget and tool to manage energy use • Lower expenses and improved reliability of impact estimates once AMI is in place • Remote diagnostics and trouble-shooting available	Cons: • Expensive to maintain until AMI is in place. • No feedback on status or impacts until AMI is installed • Possible expense to swap out communications boards when AMI installed • Ease of over-ride with some thermostats

This scenario is identical to Scenario C with one significant difference. This scenario assumes that AMI is installed within 5 years and that the AMI system provides a means for electronically returning data from the thermostat to the utility (without the need for on-site visits to each thermostat). (As discussed under scenario B, note that this report addresses AMI as a scenario assumption in order to examine the complete range of possibilities, but does not take a position on the overall economics of AMI which go well beyond its impact on a single AC DLC DR program.) After AMI is in place, the existing radio infrastructure would continue to be used to send out control signals to thermostat as it can do so cost-effectively and is well suited to rapidly sending signals out to thousands of thermostat. The thermostat will communicate with the AMI system through some kind of wireless protocol, whether that is ZigBee or one of the other protocols being tested in the market. At this point in time it is not clear which wireless protocol will be most appropriate as the standards and technology are still undergoing rapid evolution. However, this scenario assumes that some wireless protocol will emerge to provide reliable communication between the AMI system and the thermostat.

Automated return communication through the AMI system will reduce the significant maintenance costs associated with finding failed or missing thermostats. The automated return communication will enable program managers to identify with a reasonably high level of certainty those thermostats that are no longer operating correctly. The program will then no longer need to do on-site inspections for all thermostats on a regular basis. It will do on-site inspections when the return communication system indicates there is trouble with a specific thermostat. In addition to reducing maintenance costs, the automated return communication will increase the reliability of the estimated demand savings produced by the system, enabling the program to support a claim for a higher level of savings.

Enabling communication through an AMI system would involve an extra expense to swap out the thermostat's communications boards when AMI is installed. Thermostat vendors claim that this swap-out can be done quickly and without changing the entire device for new thermostats that are new to the market or are coming on the market soon. It is not yet clear whether the vendors will provide modules that will communicate with **any** AMI system offered on the market. It is also possible that the EDCs could procure thermostats that already have hardware built in for communicating with AMI systems. However, that will entail extra costs up front and assumes that any purchase made for the 2008 control season will incorporate a communications system that is stable and appropriate for the long term.

In the cost-effectiveness analysis, it is assumed that the costs for the AMI system are not borne by the load control program but the benefits of reduced maintenance costs and improved impacts do accrue to the load control program.

3.1.5 Scenario E: Thermostat with Current Automated Return Communication Capability

Scenario E: Thermostat with Current Automated Return Communication Capability	
Description: • Communicating programmable thermostat that can implement AC cycling, temperature setback, and temperature ramping load control strategies • VHF paging with automated return communication independent of AMI • Intelligent cycling	
Pros: • Reasonably well tested hardware • Offers pre-cooling and temperature setback options • Lower operating expense if no monthly or event fees to customers • Lower expenses and improved reliability of impact estimates with feedback on status and return data • Provides customer a free gadget and tool to manage energy use • Remote diagnostics and trouble-shooting available	Cons: • Installation expense (particularly for Maingate) • Equipment reliability issues have been encountered for Maingate • Expense of using commercial paging for two-way communication • Ease of over-ride with ComfortChoice thermostat

This scenario includes most of the same features and benefits described under Scenarios C and D but it assumes that an automated return communication system is set up from the beginning, and uses one that does not depend on AMI for communication. This can be implemented in one of three ways:

Option 1. Outbound control signals and return data go through a commercial two-way paging system.

Option 2. Outbound control signals are sent using the same utility radio system described in the previous scenarios. Automated return communication is done via a gateway appliance through the customer's landline telephone line, typically in the middle of the night (it will not work when the customer's only phone is a cellphone or Internet (VOIP) phone).[10] This technology has been used in the past, but vendors may be offering more wireless and Internet gateway alternatives in the future.

[10] PSE&G tested this configuration in its myPower pilot program.

Option 3. Outbound control signals and return data are sent directly to and from the thermostat via a broadband, wired Internet connection (DSL or cable modem). Thermostats are wired through CAT-5 cable to a cable modem or DSL connection to the internet.[11]

Options 2 and 3 have several potential drawbacks and were not included in the cost-effectiveness analysis. Option 2 entails significant installation and equipment costs, is more complicated to explain to customers, is more complicated to set up and run (with risks of significant maintenance expenses), and requires customers to be willing to make their land-line phones available for the program. PSE&G encountered significant hardware failures with the Maingate gateway in its myPower pilot test of this equipment. Option 3 requires running CAT-5 wires from the Internet connection to the thermostat. It has not been implemented to date in a utility load control program.

Option 1 typically includes a thermostat connected by wires to a communications module that handles sending and receiving data through the paging system. Option 1 is less expensive than either of the other two options to install and has been implemented in several utility load control programs.[12] The communications costs can be a very significant portion of program costs. Option 1 was examined in the cost-effectiveness analysis.

3.1.6 Other Options Considered

Several options were examined but not included in the set of options for additional consideration. Some of the options that were examined but not subjected to detailed analysis include:

1. **TOU and CPP Rates.** Scenarios that included a TOU or CPP rate offered with the DLC program were considered. These rate programs could offer additional bill saving opportunities for customers. A customer with a programmable thermostat could use it to automatically shift AC use from on-peak to off-peak periods every weekday on a TOU rate and reduce their energy costs. Utilities could control both switches and thermostats during CPP periods to help customers automatically save on a CPP rate. While both of these options would make a good program offering, they were not considered in this study for two reasons. First, designing good TOU and CPP rates is complex and beyond the scope of this study. Second, both rates would require an AMI system, or special metering, for billing. This study is focused on solutions that do not require an AMI system.

2. **Switch with current two-way communication capability.** Manufacturers make switches that include two-way communication capability. Examples include Comverge's Maingate system that receives radio control signals and sends return data through the phone line, via a gateway. Corporate Systems Engineering offers a system that uses Cellnet two-way paging. Such systems offer daily feedback on the operation of each switch, which reduces maintenance costs and improves the estimated achieved demand savings. However, such systems are relatively expensive to install and their complexity places burdens on program staff and participants and increases the likelihood that maintenance costs will not be reduced as significantly as promised by the daily feedback.

3. **Switches and thermostats without intelligent cycling.** There are still control devices on the market that do not use intelligent cycling. Given the significant advantages of intelligent cycling

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[11] One manufacturer is developing a thermostat that communicates wirelessly with an router connected to a cable modem or DSL but that product is not yet on the market.

[12] E.g., Consolidated Edison and Long Island Power Authority as well as PSE&G's myPower Link pilot.

and the likely minimal extra cost, we ruled out switches and thermostats that do not offer intelligent cycling.

3.2 Vendors Contacted

Vendors contacted by Summit Blue to help gather this information[13] are listed below in alphabetical order. This is not an exhaustive list as there are other vendors in this market. In addition, some vendors were contacted that are no longer targeting residential and are now concentrating on C&I controls (e.g., Invensys and LiteStat). Section 4 describes where these technologies have been deployed.

Cannon. Cannon offers a load control switch and thermostat described below.

Carrier. Carrier offers the ComfortChoice thermostat.

Comverge. Comverge makes load control switches and offers a White-Rogers SuperStat thermostat.

Corporate Systems Engineering. Focuses on intelligent switches.

Honeywell. Honeywell manufactures thermostats that are incorporated in other vendors load control options. Honeywell also provides field support for load control programs. Honeywell is currently working with Cannon to make the ExpressStat thermostat and will be offering a new thermostat called the VisionPRO.

Proliphix. Proliphix makes a thermostat that connects to the Internet via CAT-5 cables.

[13] Based on the vendor responses, matrices of technology attributes were developed. However, they are not presented here due to rapid rate of change in these technologies. It seems like most vendors have plans to roll out new equipment in this upcoming year. There was concern that incorporating these matrices in the text (which were provided to stakeholders) might disclose some information deemed confidential by the vendors and also do the vendors a disservice by not having their most current or planned technology represented. Instead, as a matter of fairness, the vendors should be contacted to obtain the latest information on the attributes of their offers.

4. PROGRAM DESIGN OVERVIEW

This section presents a review of the types of DLC programs found in use at utilities in the United States and Canada. Section 4.1 presents an overview of major program elements across utilities. Section 4.2 draws together the different elements of DLC programs to show how they come together to create a complete program design that attracts participants.

4.1 Overview of Approach to Program Review

The FERC Assessment of Demand Response and Demand Metering, Staff Report, Docket Number AD-06-2-000 reports that as of August 2006 there were 234 entities in the United States with direct load control (DLC) programs. Almost all of them have residential AC load control programs. Thirty-three percent of them also have commercial load control programs. While most of these entities are very small municipal utilities with relatively small impacts, the ten largest load control programs account for 60% of all load control customers nationwide. PSE&G currently has one of the top ten largest DLC programs in the country based on the number of participants, but there is concern about the maintenance of the switches in the field.

A literature search was done to find program design and evaluation information on as many residential and small commercial AC DLC programs as possible. An initial list of programs from the Edison Electric Institute (EEI) Wise Energy Use database was reviewed.[14] This database maintains an up-to-date list of energy efficiency and demand response programs offered by electric utility members across the country. The database features links to the utility Web sites which describe the programs.

Additional information on programs was added by reviewing Summit Blue's reference library on demand response. This included reports from the U.S. Department of Energy (DOE), Federal Energy Regulatory Commission (FERC), International Energy Administration (IEA), Electric Power Research Institute (EPRI), Peak Load Management Association (PLMA), Association of Edison Illuminating Companies (AEIC) Load Research Committee, Lawrence Berkeley National Laboratories (LBNL) Demand Response Resource Center (DRRC) and many other white papers and individual program evaluations prepared by utilities, consultants and equipment manufacturers. Reports from E-Source provided a particularly rich source of comparative information on AC load control programs and their evolution over the past decade. Phone calls were made to some program managers to clarify information found in the print materials.

The review focused on AC DLC programs. Programs that controlled only water heating or electric space-heating were not included. Programs and pilots that focused primarily on whole house load control using demand controllers or CPP rates were also considered outside the scope of this review, although a few were included if they had a strong emphasis on AC control. Following these guidelines, the study team developed a list of fifty-four programs for review. These programs are summarized by type in Table 4-1. Table 4-2 presents a list of programs by utility.

[14] See http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/programs_and_incentives/progs.pdf

Table 4-1. AC DLC Programs Reviewed by Type

Type	No. of Programs
Thermostat Programs	6
Thermostat Pilots	12
Switch Programs	32
Combination Switch and Thermostat Programs	4
TOTAL	54

Table 4-2. AC DLC Programs in Review List with Start Year

THERMOSTAT PROGRAMS		
Austin Energy	2000	Power Partner Free Thermostat Program
Consolidated Edison - New York	2002	Cool Program (smart thermostat)
Kansas City Power & Light	2006	Energy Optimizer
LIPA	2000	LIPAedge
Southern California Edison	2002	2002/2003 Pilot, program in 2004 (Com'l)
Southern Company- Gulf Power	2000	GoodCents Select
THERMOSTAT PILOTS		
Alliant	2004	Stat Saver and Degree Saver
Colorado Springs Utilities	2005	Load Cycling Pilot Program
ComEd/Community Energy Cooperative	2004	Energy-Smart Pricing Plan
Connecticut Light & Power	2000	Thermostat Pilot Programs
GPU-New Jersey	1997	ACCESS Home Energy Mgmt Market Test
Idaho Power	2003	Thermostat Pilot
PEPCO	2007	SmartPowerDC
PSE&G – New Jersey	2005	myPower Link
Puget Sound Energy	2000	Thermostat Pilot
Sacramento Municipal Utility District	2002	PowerStat
San Diego Gas & Electric- Sempra	2003	Thermostat Pilot
Wisconsin Public Service Corporation	2005	Residential Thermostat Pilot
SWITCH PROGRAMS		
Alliant- Iowa	1988	Appliance Cycling
Alliant- Wisconsin	1988	Appliance Cycling
Atlantic City Electric (formerly Conectiv)	1980	Peak Savers Club
Baltimore Gas & Electric		Energy Saver Switch
Connexus Energy		Power Nap
Dairyland Power Cooperative		Load Management Program
Delmarva Power	1987	Energy for Tomorrow
DTE Energy (Detroit Edison)		Interruptible Air-Conditioning Rate
Duke Energy – Indiana (Cinergy)	2003	Power Manager
Duke Energy - Kentucky (Cinergy)	2003	Power Manager
E.ON US – Kentucky Utilities		Demand Conservation
E.ON US- Louisville Gas & Electric		Demand Conservation
Exelon (Commonwealth Edison)	1996	Nature First
Florida Power & Light	1987	On Call
Idaho Power		AC Cool Credit

SWITCH PROGRAMS		
Indianapolis Power & Light	2003	Cool Cents
Madison Gas & Electric	1988	Power Control
MidAmerican Energy Company- Iowa	1988	Summer Saver
Nevada Power		Cool Credit
PacifiCorp- Rocky Mountain Power		Cool Keeper
PEPCO		Kilowatchers
Progress Energy- Florida (Florida Power Corporation)		Energy Management Program
PSE&G – New Jersey	1990	Cool Customer Program
Sacramento Municipal Utility District	1977	Peak Corps
Savannah Electric		Power Credit
Southern California Edison		Summer Discount Plan
Southern Company- Georgia Power Company		Power Credit
United Illuminating- Connecticut		Cool Sentry
Vectren Energy Delivery	1992	Summer Cycler
WE Energies	1988	Energy Partners
Wisconsin Public Service Corporation	1988	Help
Xcel – Colorado	1990	Saver Switch
Xcel – Minnesota	1990	Saver Switch
THERMOSTAT AND SWITCH PROGRAMS		
Baltimore Gas & Electric	2007	New Program (name unknown)
E.ON US - Kentucky & Louisville	2000	Demand Conservation
Jersey Central Power & Light (FirstEnergy)	Switches 1991 Stats 1996	Power Plus Savers
Toronto Hydro and other Ontario municipal utilities	2006	Peak Saver (Residential Switch, Business Thermostat)

Descriptive summary information on these programs will be presented below. The detailed program information matrix can be found in the accompanying spreadsheet. It was not possible to get complete details on every aspect of every program in this list, but sufficient information was collected to get a good understanding of the nature of AC DLC programs across the country.

4.2 Summary Description: Technologies Deployed

A review of the program start years, shown in Table 4-2, illustrates that most switch programs started over a decade ago, while most new programs use thermostats.

A small number of suppliers dominate the market for both thermostats and switches. These 'big players' are Cannon, Carrier and Comverge (in alphabetical order).

While there used to be a major distinction between simple, low-cost switches and high-cost two-way communicating thermostats, that distinction has blurred over the years as switches and one-way thermostats are adding many features of the two-way thermostats and two-way thermostats are coming down in price. Each supplier has been improving their models from year-to-year and offering a variety of features. Some programs offer thermostats, yet control them in a simple manner like a switch. Austin Energy has been doing this successfully for many years. This variation in features makes it difficult to put technologies into simple categories. A high-level summary is offered here.

Among all programs reviewed that use thermostats, three programs use the two-way Carrier ComfortChoice, three programs use the one-way Comverge SuperStat, and one uses the Cannon ExpressStat. There are also two programs that use thermostats as the primary piece of a larger control system. One uses Comverge MainGate and one uses TWACS Power Line Carrier. All of the thermostats, including the Cannon ExpressStat, have been used in multiple pilots.

Among all programs reviewed that use switches, the most common models are Cannon and Comverge. New models of both of these switches offer intelligent cycling to cycle against individual customer's normal run times. One switch program mentions use of a Honeywell switch.

The largest AC DLC program in the country, Florida Power & Light's On Call program, is an interesting combination of technologies that is difficult to categorize. They use a two-way automated communication system (TWACS Load Control Responder). Power line carrier communication is used to send 50% duty cycling commands to the air-conditioners and other equipment.

Carrier ComfortChoice thermostats offer full two-way communication. Two-way communication gives the utility verification of the receipt of control messages, as well as real-time information on customer overrides. Two on-going programs use this equipment and these features: Consolidated Edison and Long Island Power Authority. The higher cost of these units is justified for these two utilities since full verification of load reduction is required by New York Independent System Operator (NYISO). Paging service to support this two-way communication costs $15 per customer per year. The PSE&G myPower Link pilot program also used this equipment.

Comverge SuperStat and Cannon/Honeywell ExpressStat are both one-way communicating thermostats that allow customers to program their thermostat and override control events via the Web.

The ExpressStat has no override button on the thermostat itself, so the software running on the Web is able to keep a log of all override events. This can give the utility valuable information without having two-way communications built into the thermostat. The ExpressStat also collects hourly run-time and indoor temperature information and stores it for 90 days within the thermostat. The data can be manually downloaded into a PDA, but this requires access to the customer's home. Care must be taken when translating the downloaded data to a PC to ensure that time stamp information is correctly synced with the hourly data. If done correctly, this can give valuable verification information to the utility, but it is not real-time and can be expensive to collect. One utility uses trained college students to perform this task to reduce the cost.

Most thermostat programs use paging systems to send out control signals. The older switch programs use FM signals and newer switch programs use paging. Many switch programs now use both FM and paging signals because they have both types of equipment out in the field, or because FM signals are needed for greater coverage of the service area. These dual coverage systems add work and cost to operations management.

FM is considered very reliable for control signals when the equipment is new, but the equipment requires monitoring and maintenance to maintain that reliability level. Problems with old and disconnected switches have reduced the reliability of many FM systems down 60% to 80% of what they once were after ten years in the field without regular maintenance.

Several programs and pilots have carefully measured the reliability of paging signals. Being able to receive a strong paging signal is one of the eligibility criteria for program participation. Most programs using paging have found that each individual site must be tested for paging reception before the installation of any control equipment. It is not possible to identify good sites ahead of time because coverage can be blocked in one building when neighboring buildings are good. In general, 10% to 20% of sites within paging coverage areas cannot receive the page, and even those that can do not always have good reception. Kansas City Power & Light found that one-quarter of homes had packet success rates[15] greater than 95%, and one-quarter had packet success rates less than 70%. The other half of the homes were somewhere in between. Southern California Edison found that 5% to 7% of return pages were not getting through. Consolidated Edison had 90% reliability on hourly data packets.

Manufacturers are working to improve reliability. One solution they are testing is message redundancy. By sending multiple signals for critical communications they create a greater probability of one of them getting through. Using these improved methods Consolidated Edison found they were able to achieve high reliability, 99%, with control and verification signals.

Systems that use commercial paging to send control signals may, under certain circumstances, encounter difficulties getting the signal out because of high demand on the communication system. For example, PSE&G's myPower pilot had trouble getting it's control signals out on one very hot day when two nearby utilities were using the same paging provider to send control signals to their much larger DLC programs.

4.3 Summary Description: Control Strategies Deployed

There are two basic types of control strategies: duty cycling and temperature offset. Duty cycling is when AC load is shut-off for a certain number of minutes each hour. For example, 50% cycling means the AC is off for 30 minutes out of the hour and on for 30 minutes. Temperature offset is when the thermostat setting is increased, so the house is allowed to get warmer than usual.

Temperature offset equalizes the load impact from each home and everyone's comfort level. Typically, with duty cycling, buildings with under-sized AC will experience greater indoor temperature increases and buildings with over-sized AC may not experience any load control at all. *Intelligent cycling* can moderate this issue by measuring pre-control runtime and applying the cycling adjustment to the baseline runtime. For example, if an AC unit is oversized and only runs for ten minutes every half hour on hot days, the device recognizes that and cuts their run time to five minutes when a 50% duty cycle is called.

It is also generally true that thermostat programs can perform duty cycling or temperature offset, but this is not always the case, especially for older thermostat programs. Many treat their thermostats like switches. Most on-going thermostat programs use duty-cycling. The typical duty cycle is 50%. Notable exceptions are Austin Energy and CPS (San Antonio Municipal), which use a 33% duty cycle.

Some of the on-going thermostat programs that use temperature offset allow the customer to choose the offset they want. Gulf Power uses the Comverge MainGate system where customers choose their own control strategies that will be triggered by a 3-tier TOU rate plus CPP periods.

In early thermostat-based programs, temperature offsets were viewed as instantaneous events. A four degree offset would immediately raise the thermostat setpoint temperature by four degrees. This usually meant that the AC would stop running for an hour or two and then it would run like normal once the new setpoint was reached. In this example, load control would only last for two hours. In an effort to even out the control on the AC over a longer control period, new temperature offset strategies are being developed and tested. One of these is the temperature offset ramp-up strategy being used by Cannon ExpressStat. With the ramp-up strategy, the temperature offset is spread out in even increments across the hours of the

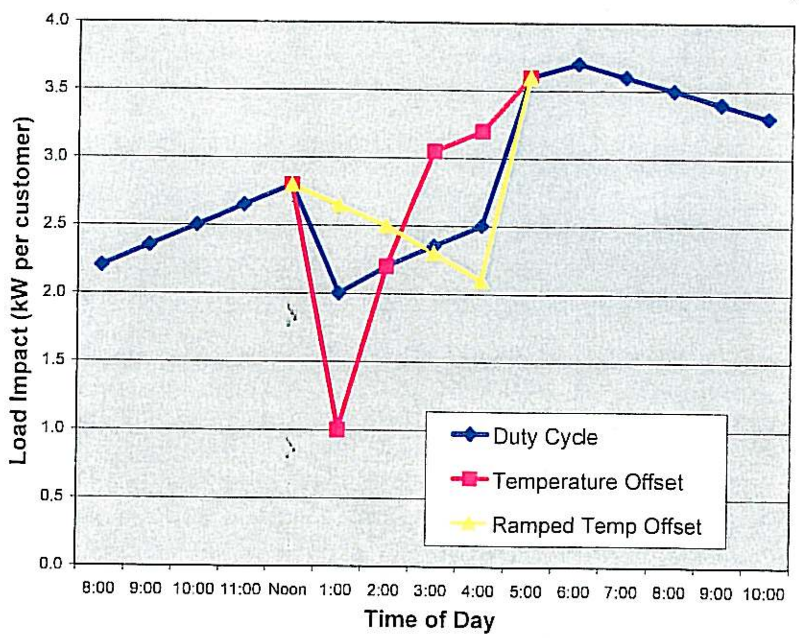
[15] The packet success rate quantifies the percentage of packets of information that successfully get to the thermostat, thus a packet success rate of 90% means 90% of the data sent to a thermostat gets there.

control period. For example, a four degree offset over a four hour control period would raise the thermostat setpoint one degree each hour. This strategy can create a small immediate impact that is sustainable over time.

New programs like Kansas City Power & Light's Energy Optimizer program and many pilot programs are doing tests to compare duty cycle vs. temperature offset. (KCP&L used a temperature ramp-up strategy.) Their experience has shown a four degree temperature offset is roughly equivalent to a 50% duty cycle, although this relationship is dependent on the length of the control event, the nature of the temperature offset, and the local climate.

Similarly, cycling strategies have evolved where an optimal impact on peak kW demand is obtained by varying the cycling time across the hours of an event. For example, there may be one hour of pre-cooling followed by 33% cycling in the first hour, 50% cycling in the second hour, 66% cycling in the third hour and dropping back to 33% in the fourth hour. Strategies like this have been deployed in pilot programs at Sacremento Municipal Utility District and in PSE&G's MyPower pilot program. Some utilities are not adopting this strategy for some events within their program. However, this type of strategy requires that the forecasters are able to be very accurate regarding the hours in which the peak system demands will occur.

Figure 4-1. Comparison of Typical Load Shapes for Control Strategies



(These load curves illustrate the typical shapes seen with the indicated load control strategies. The shapes are based on impact evaluation data from Wisconsin Public Service Corporation, Southern California Edison, and Kansas City Power and Light.)

The length of control periods varies across utilities. Some utilities have flat load curves on peak days and need load control from 1 p.m. to 7 p.m., so they are concerned about long, sustainable load impacts. Others have spike peaks and are more concerned about getting instantaneous big load drops. Allowable hours of control per day vary from two hours to eight hours, with most programs allowing four hours.

Many utilities have limits on the number of days and/or the number of hours they can call control events during one season. Limits on the number of days of control range from seven to 20, with 20 being most common. Limits on the number of hours of control range from 28 to 300, with 80 to 90 being most common. Eighty-eight hours is equivalent to 1% of all hours, which may contribute to its popularity. LIPA has the program with the lowest limit on control hours – no more than 7 days of control with 4 hours per day. Xcel has the largest limit at 300 hours, but they regularly use only 40-60 hours. Some programs do not call control periods on weekends or holidays.

Having a program actually use its full allotment of control hours is unusual. Many programs call control events only rarely in times of emergency. Thermostat programs appear to call events more frequently than switch programs, showing six to 13 events per year over the last few years. Switch programs that call events generally report four or five events per year. Many switch programs state they are only for emergencies and are rarely used.

4.4 Summary Description: Load Impacts

Many studies report load impacts for AC DLC programs. However, load impacts are dependent on many variables. The control strategy used, the outdoor temperature, the time of day, the customer segment, ease of and ability to override control, reliability of communication signals, age and working condition of installed equipment, and local AC use patterns all have significant effects on the load impact. Even within a single program, there is variability in impacts across event days that cannot yet be fully explained. Measuring impacts typically requires expensive monitoring equipment and as a result is often done on small sample sizes.

Even with all of this variability, a review of reported impacts does show some general consistencies. As expected, impacts increase as the duty cycle goes up. Table 4-3 shows the average reported kW impact for programs based on the duty cycle used.

Table 4-3. Average Load Impacts by Duty Cycle for AC DLC Programs

Duty Cycle	Average Load Impact KW/Customer
33%	0.74
45%	0.81
50%	1.04
66%	1.36

Source: Summit Blue calculations based on 20 load control impact studies.

This supports the oft-quoted rule-of-thumb that the load impact for 50% duty cycling is 1 kW per customer.

Customer type also makes a difference. In a few cases where single-family and multi-family impacts were measured separately, multi-family impacts are 60% of single-family. In the cases where small commercial impacts were measured, they are generally twice as high as residential impacts.

There is only limited data on load impacts for temperature offset strategies. Kansas City Power and Light compared four degree offset ramp up over four hours with 50% duty cycling. They found that duty cycling created twice as much load impact over the four hour control period. This makes sense as a four degree offset with ramp-up over four hours is equivalent to a 2.5 degree average temperature offset over the whole period.

Consolidated Edison and others report 10 to 20% of AC units are not running, even on peak days. This is attributed to vacations and other reasons that people are not home every day of the summer. These factors, along with unreliability of communication signals and non-working equipment, can cause average load impacts much less than what would be expected based solely on knowledge of average AC unit size.

4.5 Summary Description: Participation Rates

Participation rates in AC DLC programs vary across utilities from less than 1% of eligible customers to 45%. Utilities with programs that have run for many years with sustained attention to customer retention or recruitment show participation rates in the 20% to 25% range. Utilities with one-time or intermittent heavy promotion generally show 10% to 15% participation.

The very highest participation rates are seen among the municipal utilities and coops that have high customer identification with the utility. Sacramento Municipal Utility District (SMUD) has one of the highest participation rates at 43%. They also report that 5% of their participants dropped out after the summer of 2000 when many control events were called.

There is a natural decline in all participation due to customers moving out of a building with a switch or thermostat. Processes and resources must be in place to minimize program attrition during the move-in/move-out process. This can be a difficult and expensive process for some utilities if their customer information system cannot support this kind of marketing effort.

Many programs report a high amount of inertia in participant reactions to the program. Once a customer is signed up, they are likely to stay even if they become dissatisfied with some part of the program. It is easier to stay than to take action to remove themselves from the program.

4.6 Summary Description: Incentives, Penalties and Override Capabilities

This section discusses program incentives and the override capabilities offered by programs which are generally tied to the technology offered, i.e., the technology has built-in override capabilities and the choice of the technology can determine the override process available to customers.

4.6.1 Program Incentives

Most switch programs offer monthly bill credits to participants during the four summer months as their incentive. These fixed credits range from $3 per month to $10 per month. Most are $5 per month. One large program, Xcel, offers the credit as 15% of the energy bill so larger users contributing larger impacts receive greater compensation.

While customers like these guaranteed incentive payments, they can be uneconomic for the utilities since they must be paid whether or not control events are called. A small group of utilities have worked on improving this incentive scheme by reducing the fixed monthly credits and adding additional credits for each control event. The three New Jersey EDCs use this approach. PSE&G and JCP&L offer $4 per month in the summer plus $1 per control event. Atlantic City Electric offers $1.50 per month in the summer plus $1.50 per control event.

The new thermostat programs are dropping the fixed monthly summer incentive and offering participants a free programmable thermostat instead. The two New York thermostat programs also give a $25 'thank you' gift to encourage participation, and Southern California Edison gives a $300 per year incentive to commercial customers in their thermostat program.

4.6.2 Override Capabilities

Some thermostats allow the customer to override and cancel the control by pushing a button on their AC unit. This feature is offered to reduce customer risk and increase the likelihood of their participation in the program. It has not yet been proven how much this feature improves participation rates, but it is certainly a feature that many customers use.

In the early years of the LIPA, ConEd and SCE thermostat programs, all of them measured override rates that reached 20% to 30% by the end of a four hour event. In the 2005 PSE&G myPower Link pilot, overrides averaged 10% over all control hours for residential customers, and 20% for small commercial customers. Some of these override rates can be traced to the type of technology and the ease of making an override, along with the potential for inadvertent and unintended overrides.

Override levels are direct reductions to utility benefits and can significantly affect the cost-effectiveness of the programs. Utilities have come up with several strategies to reduce overrides and still maintain customer satisfaction and participation.

Early thermostats had an override button on their face, which was very easy for customers to use since they just pushed the button and the AC came back on. Some later thermostat manufacturers removed the easy-to-use button and but still allowed customers to initiate an override by changing the thermostat set point. This resulted in a number of customers inadvertently overriding events when they did notice that a control period was underway or children adjusted the temperature. In small businesses that may be participating in these programs, any number of people may have access to the thermostat which results in inadvertent overrides as all personnel may not be aware of the program. A number of thermostat and switch programs now allow customers to use a Web interface or a phone call to override the event. This changed the quick, spur-of-the-moment override decision to one that required some effort and allowed time for reconsideration. It also reduced the likelihood of inadvertent overrides.

Some utilities have worked with their incentive structure to reduce overrides. SCE reduces their $300 annual incentive for business customers by $5 for every override. In the PSE&G myPower Link pilot, residential customers received $2.50 for each control event if they did not override it. Similar to SCE, business customers forfeited $5 from their annual $50 incentive payment for every event they overrode.

In the second year of the myPower Link pilot, PSE&G made automated phone calls to all participants to give them advance warning of control events. Customers had indicated in surveys that this would help them reduce their need to override control periods. Advance warning would allow them to take actions, like pre-cooling their home, to keep themselves comfortable.

Some programs have simply put limits on the number of overrides that customers can use. The new Kansas City Power and Light thermostat program only allows one override per month. Overrides can be done by Web or phone but there is no button on the thermostat. First year results show that these steps did keep overrides low. Only 12% of customers used the override at any time during the summer. But process evaluation surveys showed that 50% of the participants did not realize they could override, so this low override rate may increase as more customers learn about it. Nearly 70% of participants were unaware of the pre-cooling feature of their thermostat. Perhaps if participants learn about both features at the same time they can implement pre-cooling to reduce the need for overrides. Having advance knowledge of control events would be a pre-requisite for getting this strategy to work.

The new proposed thermostat program for Baltimore Gas and Electric is planning to limit customers to two overrides per year.

Another alternative being considered for reducing overrides is a refresh on the control signal. The refresh would put all AC back on control. This may be necessary for emergency situations, but the customer communications related to this strategy would have to be carefully crafted to maintain customer satisfaction with the program.

4.7 Summary Description: Marketing Strategies

Many switch programs are in maintenance mode and little marketing is done. For new thermostat programs, and for all programs that are concentrating on maintaining or growing participation, the most common marketing strategy is direct mail. Response rates of 2% to 3% for utility load control promotions are common for residential customers from a direct mail campaign if it is targeted to high use customers. Small commercial response is lower, close to 1%. In situations where a quota must be met, direct mail is followed up with telemarketing.

Southern California Edison has had success with bilingual door-to-door promotion of the program for commercial customers. This marketing technique has the added benefit of being able to identify eligible sites in the same visit and can improve the efficiency of the installation visits.

LIPA has found home shows to be one of their most effective marketing strategies for residential customers.

Other marketing methods that utilities have used are TV ads, radio ads, Web sites, bill stuffers, newspaper ads, community ads, utility newsletters, billboards, and HVAC contractor networks. One program only promotes to new utility customers. Many programs rely on word-of-mouth.

When Florida Power and Light began their On Call program in 1987, they promoted it heavily using television ads, bill inserts, print ads, and direct mail. Now they rely entirely on word-of-mouth, and they are getting 300 calls per week and 70 Web hits per month from customers who are interested in the program. They have an 80% closure rate on these inquiries. Customers in the On Call program typically save 5% to 20% on their electric bill through participation, based on the number of devices they are able and willing to put on controls. Being able to achieve a level of savings this high enables the success of the word-of-mouth marketing strategy.

Another strength of the FP&L marketing strategy is their attention to new homeowners. When a new customer moves into a home with On Call control equipment, they receive a letter telling them about their opportunity to continue in the program. The new customer is automatically enrolled in the On Call program unless they notify FP&L that they want to opt-out. This new customer recruitment and opt-out strategy is an essential part of any program that wants to maintain and grow participation rates. Unfortunately, not all utilities have customer information systems that can support this type of marketing effort.

A few programs and pilots have tested different marketing messages. A recent study done by Kansas City Power and Light found that 59% of customers mentioned 'Saving money' as a primary motivator for their participation in the program. 'Save energy' was mentioned as a primary motivator by 30%. 'Take control' did not resonate with customers.

Wisconsin Public Service had success with a 'help us help the environment' message over many years. They recently tested a dual promotion of their DLC program with their green rate program in a targeted direct mail campaign timed with Earth Day. Customers were encouraged to use their incentive from the DLC program to buy green energy. They could do two good things for the environment with no net impact on their bill. This dual promotion did not work, primarily because two different sign-up methods were required for the two programs: one by mail and one by phone. This reinforces the importance of simple, customer-friendly application procedures.

The E.ON Web site is a good example of customer-friendly application procedures. Even though their program has the complication of two device offerings for the customer (switch or thermostat, one with an annual incentive and one without), they have been able to present it in simple terms that are easy to understand. A toll-free phone number is provided and allows customers to quickly find out more information and apply for the program.

Programs work hard to improve their pre-screening process to identify eligible participants before an installer makes a site visit. In the myPower Link pilot, PSE&G found that 15% of interested customers drop out after learning more about the program on the phone, and another 15% of residential customers and 30% of small commercial customers do not pass the pre-screening. Thorough pre-screening is another important part of keeping programs cost-effective.

Developing a strong relationship with HVAC contractors is another requisite part of a successful thermostat program. Not only will they be potential installers and promoters of the program, but their understanding is essential for HVAC trouble calls that arise with customers in the program. E.ON fosters this relationship by hosting monthly meetings with the HVAC contractors.

4.8 Summary Description: Customer Satisfaction

Program evaluations for AC DLC programs typically show high levels of overall customer satisfaction. Of course, it must be remembered that participants are a small percentage of all residential customers. Those that choose to participate like it.

Only a few studies have reported dissatisfaction rates of 20% or higher. One was a SMUD evaluation done in 2000 after incentives had been drastically cut and cycling levels had been raised. Five percent of customers left the program because of these changes. Given the magnitude of the changes, it is surprising that only 25% of customers were dissatisfied. This points to the inertia of program participants to make a change.

The other high dissatisfaction rate of 27% was reported in the recent program evaluation of the new Kansas City Power & Light thermostat program. Dissatisfaction was primarily related to those who previously had manual thermostats and felt the new programmable thermostats were more difficult to use. Many of the dissatisfied customers also felt they needed more help during the installation of the thermostat to learn how to use it. This is something that can be remedied, but attention must be paid to the cost of the effort.

More help at the time of installation may reduce the need for follow-up phone calls. KCP&L found that 33% of their participants called in for help at least once. Only 12% ever tried to use the Web interface. This is not uncommon. Consolidated Edison, with an established thermostat program, reports that 11% of their customers call their Infoline for help during the year and only 12% use the Web. At LIPA, 22% report using the Web. Having a Web-enabled thermostat is not an important feature for most participants.

Sacramento Municipal Utility District did some extensive research work to understand the importance of incentives vs. cycling levels for creating customer satisfaction. In regular surveys, customers stated that incentive levels were much more important to them than cycling levels. However, a conjoint analysis indicated that cycling levels were more important to customers than incentive levels. By offering sets of trade-offs, conjoint analysis can reveal the subconscious motivations customers act upon.

Perhaps these apparently conflicting results just support the findings reported in other studies, that AC DLC customers want bill savings and painless participation. This desire for painless participation has been reflected in the evolution of AC DLC programs over the years. While many programs started with 100% and 67% load cycling options, most have moved to 50% or lower. Many studies report that few customers feel any discomfort at 50% cycling levels, and most customers don't even notice the control events.

4.9 Comparison of Program Designs

This section draws together the different components of DLC programs to show how they come together to create a complete program design that attracts participants. Section 4.9.1 highlights switch-based programs with the highest participation rates. Section 4.9.2 in a comparison of the thermostat-based programs.

4.9.1 Comparison of Switch-based Programs

Technologies, control strategies, customer incentives and marketing approaches all work together to create successful AC DLC programs. Customer participation rates are one useful indicator of how well an overall program design works if the goal is to achieve as much cost-effective load reduction as possible.

Table 4-4 shows the leading switch programs with the highest participation rates. These participation rates were estimated based on the eligible population, namely customers with central air-conditioning.

Table 4-4. Switch Programs with the Highest Participation Rates

Utility	Participation Rate*
Baltimore Gas and Electric	45%
Sacramento Municipal Utility District	43%
Xcel- Minnesota	40%
Detroit Edison	32%
PEPCO	30%
Madison Gas and Electric	25%

Source: Summit Blue review of program documents, personal communication. See bibliography for sources.

SMUD and Xcel have had continuous strong marketing programs over many years to support their high participation rates. SMUD has concluded that 43% is their full saturation rate for the program and they are unable to achieve any more. Xcel is continuing to sign-up new participants.

Madison Gas and Electric is an example of a program with a very high customer benefit. Customers receive $8 per control hour for 100% duty cycling (load shed). Because of the high cost of control, the program is rarely used. Customers are willing to sign-up because there is little comfort at risk. The program serves the utility as an 'insurance policy' for emergencies.

4.9.2 Comparison of a Sample of Programs

Table 4-5 summarizes the main components of eight AC DLC programs that use thermostats or switches in conjunction with an AMI system for controlling AC loads. They are grouped by technology to emphasize the impacts that other program design components can have on participation rates.

Table 4-5. Example Thermostat Programs and AMI Linked Programs

Utility	Year Started	AC Control Strategy	Incentive	Participation Rate* and Participants
Group 1: Thermostat with Gateway or Switches with AMI				
Gulf Power	2000	Customer choice	3-tier TOU plus Critical Peak Rate; customer charged $4.35/month	1% 3000
Florida Power & Light	1987	2-way TWACS Power Line Carrier	50% duty cycle only using switches	25% 741,000
Group 2: Thermostat with Automatic Return Communication				
Long Island Power Authority	2000	50% duty cycle	Free thermostat installed Plus $25 'thank you' bonus	7% 25,000
Consolidated Edison	2002	50% duty cycle	Free thermostat installed Plus $25 'thank you' bonus	2% 17,000
Southern California Edison (Business Customers Only)	2003	Customer choice	3-tier TOU plus Critical Peak Rate; Free thermostat installed Plus $300 'thank you' bonus	1% 10,000
Group 3: Thermostat without Automatic Return Communication				
Austin Energy	2000	33% duty cycle	Free thermostat installed	21% 53,000
Kansas City Power and Light	2006	Tested 50% duty cycle And temperature offset	Free thermostat installed	3% (first year) 8,000
Group 4: Combination Switch and Thermostat				
E.ON Kentucky Utilities and Louisville Gas and Electric	2000-switches 2005-thermostats	45% duty cycle	Customer chooses between a switch and 20$/year bill credit OR a free thermostat installed with no annual bill credit	38% (see Note 1) 91,000 switches 1000 stats
Jersey Central Power and Light	1991-switches 1996-thermostats	50% duty cycle	Free thermostat installed. Switch customers received 16$/year bill credit And 1$ per control event	30% (see Note 2) 59,000 switches 21,000 stats

Source: Summit Blue review of program documents.
**Based on eligible population – These participation rates must be interpreted carefully as some were pilot-type programs*
Note 1: Most of these are switches since the thermostat option did not begin until 2006.
Since the beginning of choice, 70% of customers have chosen the thermostat option.
Note 2: The program is in maintenance mode and there has been customer drop-out over the years.
30% of the eligible market is or was in the program.

Technology Group 1: Gateway or AMI-Linked Programs

The first technology group in Table 4-5 is for thermostats (or switches) that work with a gateway system. They have two-way communications and they control multiple devices within the customer's home, although a thermostat on the AC is usually the primary device. While the Florida Power and Light (FPL) On Call program is not a thermostat program (it is entirely switch based), it does control multiple devices and it is tied into their AMI system. FPL has built its market share up to 25% of the eligible population. The original equipment did 100% duty cycling (load shed) during control events and the incentive was $42 per year. In 2003, the duty cycling was cut to 50% and the incentive was cut in half.

The Gulf Power Good Cents Select Program is a thermostat based program. The program does not offer an incentive. Instead, the customer pays a monthly charge of $4.35 which covers 60% of the cost of installing the gateway and other control equipment. Customers receive their incentive by taking advantage of the CPP rate. On average, customers reduce their usage by 22% during the high price time period, and by 41% during CPP periods. The CPP rate is 30 cents per kWh. Although Gulf Power had originally hoped to get 10% of eligible customers participating in this program, participation has not exceeded 1%. This indicates that few customers see benefits at the current electric rates if they must cover a significant share of the cost of the expensive gateway systems themselves.

Since gateway systems have been expensive, it is reasonable that they are being used in areas of the country that have significant air-conditioning loads, as well as electric space-heating, electric water-heating and pool pumps. This is where they are most likely to be cost-effective for the utility. Florida Power and Light electric load is predominantly residential, so their demand response options are limited in the commercial and industrial sectors. Other utilities have looked for lower cost control options.

Technology Group 2: Two-Way Communications

The second technology group in Table 4-5 is the two-way thermostat group. At the present time, all of these programs use the Carrier ComfortChoice thermostat and commercial paging systems to achieve two-way communications. This thermostat allows 100% verification of the receipt of control signals and real-time notification of customer overrides. While the equipment cost is less than gateway systems, the communication system for these thermostats is very expensive. While only a few pages are required to send out control signals to large groups of customers, each customer must return an individual page for verification. The paging cost is estimated to be $15 per year per customer.

Even with this extra cost, the two-way thermostat is popular with the New York utilities who are required by the New York Independent System Operator to verify all of their demand response load. It has also been found to be cost-effective for business customers, but not residential customers, at Southern California Edison.

All utilities in this group offer free thermostat installation and a one-time 'thank you' cash incentive. Because of the high cost of operating this thermostat, there is little money available for annual incentives for customers. This is probably part of the reason that participation rates are low for this technology. Long Island Power Authority has achieved a 7% participation rate with a strong appeal to civic-minded citizens in their community, while the other programs are in the 1% to 2% participation range. This suggests that the extra value of the two-way thermostat largely appeals to the utilities, not to customers.

Technology Group 3: One-Way "Type" Thermostats

The third technology group in Table 4-5 are the one-way thermostats, however, this can be misleading as all programs have some sort of return communications either from a sample or a visit to the site to collect the data (e.g., Cannon's one and a half communications system). Austin Energy uses the Comverge SuperStat and Kansas City Power and Light uses the Cannon ExpressStat. Both of these thermostats are a lower cost alternative to the Carrier ComfortChoice. They provide the same customer benefits of programmable thermostat settings and control event override options that the two-way thermostats provide, but at a much lower cost. Typically the one-way thermostats cost $200 compared to $100 for a switch. They also offer utilities the opportunity to use the thermostat as a customer incentive instead of an annual bill credit, thereby reducing the cost of the program

This strategy of offering the free thermostat as the incentive seems to be working better for this group of utilities than it did for the two-way thermostat group. Austin Energy has achieved a 21% participation rate. Part of this may be due to civic-mindedness, and part may to due to the fact that they use a 33% duty cycle for control events. This should be barely noticeable to customers. The jury is still out for the Kansas City Power and Light program, although they got off to a good start by achieving 3% participation in their first year of the program.

Kansas City Power and Light tested both 50% duty cycling and 4 degree temperature offset with ramp-up for their control strategy. They concluded that 50% duty cycling provided twice as much load impact benefit to the utility. It is yet to be seen if they can achieve a 21% participation rate like Austin Energy if they use a 50% cycling strategy.

All of the thermostat programs use duty cycling or customer choice for their control options. None of them use temperature offset on a regular basis, even though that was one of the original advantages touted for thermostat control instead of switches. Duty cycling provides reliable load impacts for the utilities, and intelligent cycling on switches provide comfort benefits for participants similar to the advantages of temperature offset. So far, temperature offset does not appear to be an important feature for either utilities or participants, however, as these programs are moving into the small business sector, there is a preference being shown for temperature set back for these customers (e.g., see the LIPA and ConEd programs).

Programs Offering both Switches and Thermostats

The fourth technology group in Table 4-5 includes the utilities that offer both switches and thermostats. The Jersey Central Power & Light (JCP&L) system began with Comverge switches. Starting in 1996, all new installations were Comverge thermostats without monetary incentive. Both technologies are controlled in the same manner and incented in the same way. It shows that both switches and thermostats can work compatibly in the same program. The JCP&L program has been in a maintenance mode for several years without any recruiting of new customers because of aging infrastructure. They estimate that 30% of the eligible market either is or has been a program participant.

E.ON (Kentucky Utilities and Louisville Gas and Electric) has offered a switch program since 2000. In 2006, they started giving customers the opportunity to choose which technology they wanted. They could choose a switch and receive an annual incentive of $20 a year, or they could choose free installation of a programmable thermostat and no incentive. Seventy percent of customers chose the thermostat option. This reduces annual incentive payments for the utilities and provides additional customer satisfaction by allowing customers to choose the technology that they prefer. Both the Comverge switches and the Comverge thermostats are controlled by the same system in the same manner, so there is little additional overhead in offering customers this choice. E.ON has supported their program with a consistent marketing campaign and a strong emphasis on ease of customer sign-ups as can be observed in their on-line Web information. With this strategy they have reached a market participation rate of 38% and they are still growing.

The final group in Table 4-5 highlights a similar combination switch and thermostat program, but this one is in the proposal stage. Baltimore Gas and Electric is proposing a two-way thermostat or switch program that will offer a $50 per year annual incentive. They are hoping to reach 60% of their eligible market with this new program.

Sixty percent participation is a challenging goal, but the incentive being offered is higher than anything that has been seen before so it may be achievable. Plus, Baltimore Gas and Electric has the highest participation rate for a switch program at 45%.

5. Assessing Cost-Effectiveness

Assessing the cost-effectiveness (C-E) of demand response programs requires the compilation of data from many sources to formulate the best possible assumptions on what the program will be, how many customers will participate, what it will cost, and the value of the reductions that may be achieved by the program. Some assumptions may be the same for all of the technology scenarios from Section 3. Other assumptions vary due to the characteristics of the technology that is the focal point of that scenario. Following is a description of the major assumptions developed for and used in the C-E scenarios.

5.1 Avoided Capacity Costs

All of the C-E scenarios are run for two different avoided capacity cost assumptions, $100 per kW per year and $65 per kW per year. Estimating the appropriate value of avoided costs from DR programs is one of the more difficult tasks in a C-E assessment. Any estimate is subject to uncertainty. For example, the future costs of supply-side options will depend upon fuel input costs and uncertain environmental compliance costs in the future. While these plant cost considerations will affect the future stream of avoided costs, bids into PJM capacity auctions will also be impacted by regional transmission capabilities. The approach taken here is to provide a range for the C-E assessment based on two different methods for valuing avoided capacity costs that produce a low and a high estimate. In general, it was determined that these two values presented a balanced view of avoided capacity costs for use in the C-E analyses. But, these are not bounding scenarios. Cases were presented by stakeholders in discussions that would result in both higher and lower avoided capacity costs than those used in these scenarios. However, these two estimates balance out the "low" and the "higher" views and were deemed appropriate for use as a range in this assessment – an assessment which is designed to focus on distinguishing between different AC DLC approaches and not the estimation of total benefits of an AC DLC program.

Two benchmarks were used to develop this range:

1. The cost of new capacity was estimated to be approximately $100 per kW per year based on conversations with stakeholders and comparisons to other estimates developed in other regional avoided cost studies. This is believed to represent a high avoided capacity cost scenario, but should not be viewed as a bounding scenario. It is an estimate that falls into the higher range of avoided costs.

2. The results of the April 2007 PJM Reliability Pricing Model (RPM) auction for short-term capacity were considered. The Final Zonal ILR price was $177.51 per MW per day, which is equivalent to $65 per kW per year.[16] There is currently no equivalent auction for long-term capacity, so market-based long-term avoided capacity costs are unknown, but this was believed to represent a "low" scenario, but not a lowest case bounding scenario.

These benchmarks are believed to be appropriate for this application which is meant to examine different AC DLC program options. Higher or lower avoided capacity cost estimates are likely to make all the program options, in general, equally more cost-effective or less cost-effective.

[16] $177.51 ÷ (1000) then multiplied by the number of days in a a year (i.e., 365) to get $ in kW per yr. This comes out to be $64.79, which was rounded to $65 in the C-E analysis.

In the PJM market, all capacity value is built around the summer peak load, so 100% of this avoided cost will be assigned to the load control impacts that can be achieved during the five highest load days.

5.2 Control Strategy

Current practice in New Jersey is to prepare to call control periods whenever the day-ahead price of energy in the hours between 2 PM and 4 PM exceeds $250 per MWh and the weather criteria is met. In 2006, five control events were actually called. Based on real-time prices for 2006, it appears reasonable to model seven real control events per year for a total of twenty-eight control hours. Events would last from two to six hours each. This would provide load control during the peak cost hours on the PJM system.

PJM looks at the five highest load days to determine peak contributions for each utility. As a result, expecting to call for curtailments seven times should cover this requirement.

Twenty-eight hours of control is consistent with the actual hours of control called by other utilities that maintain their participation levels. The limits on the number of control hours are higher, though, and are commonly set at 100 hours per year and 8 hours a day to cover any extreme emergencies that may occur. These limits do not affect the C-E scenarios.

For the examination of these technology scenarios, the C-E scenarios will assume 50% cycling across all control hours. In reality, however, a flexible cycling strategy may be able to deliver greater load reductions. An example of a flexible cycling strategy would be starting a control event at 33% cycling in the first hour, moving to 50% cycling in the second hour, 60% cycling in the third hour and 33% cycling in the last hour. If the hour of summer peak can be correctly predicted, this will create an optimal amount of load reduction during the peak while maintaining customer comfort and reducing snapback from the event. In the recommendations section, the importance of deploying a technology that provides flexible control strategies is viewed as an important technology specification.

5.3 Avoided Energy Costs

Hourly real-time pricing data for the PSE&G, JCP&L, and AECO nodes in the PJM market during the summer of 2006 was used to determine the avoided energy costs during the hours when prices were greater than $250 per MWh. Results are shown in Table 5-1. Based on an analysis of this information, a value of 43 cents per kWh was used as the avoided energy cost in the C-E spreadsheet model.

Avoided energy costs during the control period are offset by additional energy costs during a snapback period that is expected to occur immediately after the control events. The impact of snapback is not measured or reported as frequently as the impact of control, and it is dependent on the temperature and the cycling strategies used. A limited amount of data was found and its transferability to this study is unknown because of a lack of detail. A Consolidated Edison impact study on small business customers reported a snapback of +0.5 kW per customer for two hours after a four hour control period. The impact during the control period was -2.3 kW per customer. Kansas City Power & Light reported a snapback of +0.5 kW for four hours after a four hour control period for a residential program. The impact during the control period was –1.1 kW per customer.

The snapback assumption used in this study is 50% of the energy curtailed during each event. While this snapback represents a reasonably high fraction of the energy savings obtained during the control event, it usually occurs during hours where the cost of energy is substantially less than the cost of energy during the hours that comprise the control event. Table 5-1 shows the average prices for energy during the two hour snapback period. An energy cost of 16 cents per kWh will be used in the C-E model.

Table 5-1. Energy Cost Data from PJM for Summer 2006 (based on Hourly Real Time Prices)

	No. of Summer Days when Price Exceeded $250 per MWh	No. of Hours when Price Exceeded $250 per MWh	Average Price During Modeled Control Hours	Average Price During Modeled Snapback Hours
ACE	7	33	42 cents/kWh	18 cents/kWh
JCP&L	7	27	43 cents/kWh	15 cents/kWh
PSE&G	7	26	43 cents/kWh	16 cents/kWh

Source: Summit Blue analysis of data from PJM, May 2007. Each utility is on a different price node and thus faces different prices.

If participants receive a programmable thermostat and they use setback in the winter and setup in the summer to reduce their energy bill, there will be additional avoided energy cost benefits for the utility in addition to bill savings for the customer. This additional avoided energy cost benefit is real, but the complications of modeling winter space-heating savings are beyond the scope of this study and will not be included in the C-E scenarios. It is an additional benefit that could be modeled and added in the future.

5.4 kW Impact per Air-Conditioner

A value of 1.1 kW per device is used for the impact of 50% cycling during control periods in a fully-working system. This estimate is a composite of data from two sources.

Source #1: New Jersey Appliance Cycling Programs Strawman Multi-Year Plan, Lawrence Berkeley National Laboratory, January 27, 2005, page 1

Table 5-2. New Jersey Load Impact from LBNL 2005 Study

	PSE&G	JCP&L
Reported kW	0.85	0.722
Non-working Pct	30%	30%
Adjusted kW	**1.21**	**1.03**

The Reported kW "unit load impact is a 'net' value, as it includes and accounts for missing and inoperable switches." It is adjusted upwards for this analysis to represent the load impact of a fully-working switch system. The load impact is the average value over the control event.

Source #2: A Regional Model for Estimating Load Impacts of Active Load Management/Direct Load Control Programs, RLW Analytics and Lawrence Berkeley National Laboratory, March 1, 2006, Page 26

Table 5-3. New Jersey Load impact from 50% cycling at 84 degrees at 5:00 p.m. using pooled utility data

Strata	kW load reduction	Share	Weighted kW
<1600 kWh/month	0.48	24%	.10
>1600 kWh/month	1.03	76%	.78
Total			.88

This value assumes all units are working, but it does not include losses.

Applying a losses factor of 13% gives a final impact estimate of .88 x 1.13 = **0.99 kW**.

An estimate of 1.1 kW per unit is used in the C-E scenarios and reflects a composite of these three values (1.21, 1.03 and 0.99). PSE&G has the largest share of control units, but the pooled data is more recent. Recent evaluation work done for other utilities shows comparable values (examples: 0.9 to 1.1 kW at Kansas City Power & Light for 4-hour 50% cycling events for single-family homes, 1.12 kW at 66% cycling at an outdoor temperature of 95 degrees plus for Louisville Gas & Electric).

A reserve margin factor of 15% should be added to these load reductions as an additional benefit. The load reductions for an AC DLC program occur at the load site and reduce overall peak demand. As a result, there is a reduction in the reserves needed, i.e., the lowered demand also lowers the needed MW reserves. PJM has a 15% reserve margin. If the load is not on the system, this reserve margin is not needed.

5.5 Control Device Equipment Costs

Interviews with manufacturers and vendors, program summaries from utilities, and information from the New Jersey EDCs were used to estimate the typical costs for purchasing and installing control equipment. These numbers are rounded, general order-of-magnitude approximations and are based on large volume installations. As part of the recommendations, it is suggested that a formal RFP process be undertaken to ensure that the equipment with the specified functionality can be provided for a specific cost. The estimates obtained from the industry – manufacturers, utilities implementing programs and secondary sources – are adequate for a screening study, but should not be the basis of a contract. Manufacturers need to have the opportunity to provide their best quote through an RFP process and have the opportunity to develop a tailored technology solution that also meets the overall specifications of the program design.

The installation of the switch requires a special permit in New Jersey. This permit fee varies by township and is assumed to be $30 per customer for the purpose of this study. Installation costs for one-way switches and one-way thermostats are equal before application of this fee. While thermostat installations are more complex because they require entering a customer's home and arranging a scheduled installation time, they do not have to be installed by a licensed electrician. A licensed electrician is required for installation of a switch.

Vendor information on two-way thermostats provided a list price of approximately $250, with a discount likely to be available on large volume purchases. A 10% discount is assumed for this study because the volumes would be large. Comparison of vendor information indicates that installation time for a two-way thermostat is expected to be twice as long as installation of a one-way switch or thermostat. An extra piece of equipment, the input/output communication device, needs to be placed closer to the heating/cooling units.

If a switch or thermostat is installed today with the intention to have it communicate with an AMI system, it should include a built-in communications port that will allow easy plug-in of the required AMI communication device in the future. The extra cost of this communications port on a large volume of devices is estimated to be $30 per unit for the purpose of this study. It would have to be specified and included in an RFP to get actual prices.

Table 5-4. Typical Costs for Control Devices

	One-way Switch	One-way Thermostat	Two-way Thermostat
Purchase Cost	$100	$200	$225
Additional Cost for Communication Port to link to AMI Plug-in	$30	$30	
Installation Cost	$130	$100	$200

Source: Summit Blue interviews with manufacturers and vendors and secondary research. May 2007.

5.6 Customer Incentive

New Jersey EDCs currently offer incentives to switch participants as part of their direct load control program. PSE&G and JCP&L offer $4 per month plus $1 per event. ACE offers $1.50 per month plus $1.50 per event. $4 per month plus $1 per event will be used as the incentive for switch programs in the C-E scenarios. This rate design for a switch program strikes a good balance between guaranteed savings for the customer and price-based incentive payments for the utilities.

For the thermostat programs, the recommendation is that there will be no annual financial incentive. Instead, the customer will receive a programmable thermostat installed at no cost, initial programming of the thermostat, and additional information on how to save on energy costs by using the thermostat. Recent focus group work in New Jersey indicates that financial incentives are important to customers in their initial decision to participate. A $50 one-time 'thank you' payment should be tested to attract customers to the program and to encourage sign-ups from new customers who move into a home with one of these thermostats already installed. As part of that test, the EDCs should craft rules for when and under what circumstances to give the thank you payment. For example, some programs give the incentive after the first summer to provide additional encouragement for the participant to stay in the program. While it is difficult to predict the exact effect of any specific incentive amount, this was compared to offers made in other programs and adapted to fit the circumstances in New Jersey. This incentive design benefited from project stakeholder input. The EDCs should monitor their success in marketing the program and modify the signing bonus as needed to manage their sign-up rate.

All customers with a programmable thermostat could use it to reduce their energy bills year-round by using automatic nighttime setback in the winter and daytime setup in the summer. This would provide an additional customer incentive, but the complications of modeling winter space-heating savings are beyond the scope of this study. The additional customer incentives received from this type of use of the thermostat will not be included in the C-E scenarios.

5.7 Participation Rates

All residential customers with central air-conditioning that live in areas that can receive control signals are considered eligible for the direct load control program. This includes single family and multi-family housing units. In JCP&L territory, only the central region is covered by the current RF system.[17]

Information was received from the three EDCs on central air-conditioning saturation rates in their service territories. JCP&L reported that 65% of their customers have central air-conditioning. PSE&G provided their 1999 Appliance Saturation Study which reported a 50% saturation rate. ACE's 1994 Appliance

[17] Source: e-mail communications from Chris Siebens, Manager-Demand Response Programs, JCP&L, received 4-17-2007.

Saturation Study showed a 39% saturation rate. The PSE&G and ACE studies are old and the national DOE RECS study reports increasing central air-conditioning rates in the Middle Atlantic region during that time. The exact saturation increase for PSE&G and ACE is unknown. An estimate of 55% saturation was used for both PSE&G and ACE.

Table 5-5 shows the estimation of eligible residential customers and participants as of 2003 based on the best data available. Combining data for all three service territories, 14% of eligible customers were program participants in 2003.

Table 5-5. Eligible Residential Market and Program Participation

	PSE&G	JCP&L	ACE
Residential Customers	1,800,000	960,000	450,000
In Coverage Area†	1,800,000	563,000	450,000
Central AC Saturation	55%	65%	55%
Eligible Customers	990,000	366,000	247,500
2003 Participants	125,000	74,000	20,000

† Area covered by the existing control system radio towers.
Source: Summit Blue analysis of data from secondary sources cited previously and Appliance Cycling Program "One Pager" Overview, 2003, attachment to e-mail provided by C. Siebens, March 7, 2007.

Participation rates for direct load control programs vary across the country. Utilities that have offered high annual incentives to attract participants and/or put continued emphasis on participant recruitment achieved the highest participation rates. Examples are Sacramento Municipal Utility District, Baltimore Gas and Electric, E.ON US, Dairyland Power Cooperative, and Xcel-Minnesota. These programs have achieved participation rates higher than 20%. It is more typical to see participation rates in the 10% to 20% range. Austin Energy, Alliant-Wisconsin, Detroit Edison, Duke Energy-Indiana, Indianapolis Power & Light, Madison Gas & Electric, Mid-American Energy Company- Iowa, and Wisconsin Public Service Corporation are examples in this group. There are also many programs that have less than 10% participation, however, it is not clear how aggressively these programs have been marketed to customers in recent years.

Expectations for participation in programs that are now being rolled-out are generally higher due to new technologies that get targeted load reductions and have a smaller impact on customer comfort, integrated marketing efforts (e.g., with utility programs that may be pricing, energy efficiency, or tied to information on an AMI rollout), and increased customer awareness of energy markets and environmental issues.

The incentive levels and number of control hours proposed in the C-E scenarios for switches are moderate. They are neither the highest nor lowest ever offered. With the assumption of moderate incentive levels and number of control hours, it is likely that the achieved participation rate will also be in the moderate range. Given that the New Jersey EDCs had a 14% participation rate in 2003, a reasonable estimate of participation in an updated switch program would be 17%. This is the assumption employed in the C-E analyses.

As with switch programs, participation rates for thermostat programs have also varied substantially across utilities.

Austin Energy has achieved better than 20% participation in their thermostat program. They have used 33% cycling rates for minimal customer impact. Also, municipal utilities tend to show higher participation rates due to customer identification with their objectives.

Other thermostat programs have shown participation rates less than 10%, often because they are new and their ultimate penetration rate is still unknown.

E.ON U.S. started offering customers a choice between a switch with an annual financial incentive payment and a free installed thermostat with no annual incentive. After one year of operation, the program manager reports that 70% of new customers are choosing the thermostat option instead of the switch. It is unknown, however, how many of these customers would participate if only the thermostat were offered. Would the customers who chose the switch be willing to participate if their only choice was the thermostat with no annual financial incentive? Did the offering of the thermostat attract new customers that would not have participated in a switch program? The answers to these questions are unknown.

Since there is no clear evidence that the type of control equipment offered (switch or thermostat) influences the overall participation rate, all thermostat scenarios in this study will assume a 17% participation rate which is the same as the switch scenarios.

The C-E study does not include a scenario where customers are able to choose between a switch and a thermostat because the costs of each are different and would need to be analyzed separately. The results of two scenarios could be combined, however, to estimate the costs and benefits of this type of program.

Eight percent of customers currently participating in New Jersey direct load control programs have two central air-conditioners and need two control devices installed. This same percentage will be used in the C-E scenarios to estimate the number of devices needed.[18]

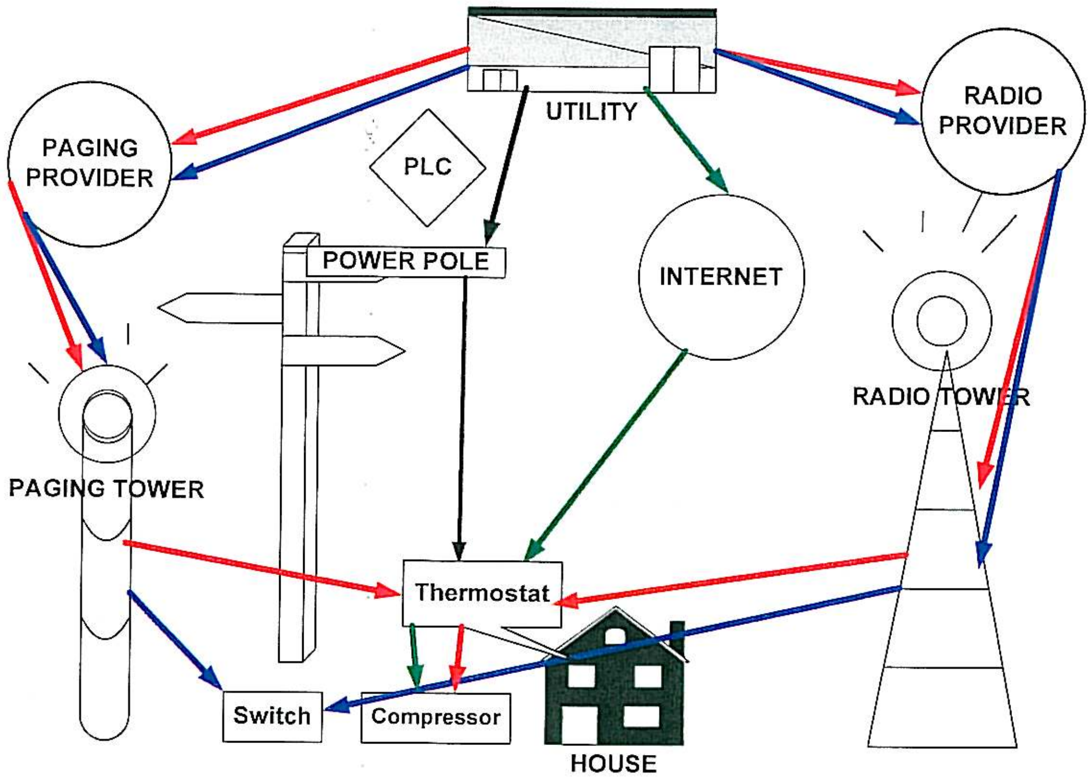
5.8 Communication System Costs

Communications systems are the part of DR programs that are undergoing the most rapid changes with a number of new systems just beginning to be offered in the market (e.g., communications through the AMI system to the meter and then from the meter to the thermostat for control events, pre-cooling, and automated event strategies). These new systems are being pilot tested, but long term results are not available. Still, these technologies generally look robust and a careful look at the way in which communications will be handled in any program is a critical success factor for the program.

Communication systems have two parts: outgoing communications and return communications. Outgoing communications send control signals to the device. Return, inbound communications provide information on whether or not the device received the signal and how the air-conditioning load responded to the signal. There are several options for both outgoing and return communications systems. The costs of these options will be discussed below. Figure 5-1 below presents a rough schematic of possible outbound and inbound communication channels.

[18] Source: Appliance Cycling Program "One Pager" Overview, 2003.

Figure 5-1: Rough Schematic of Outbound and Inbound Communication Channels



5.8.1 Outbound Communication Options

This section presents the three outbound communications options that were included in the technology options discussed in Section 3. They are:

1) Using the EDCs' current radio system (RF in the 154 MHz range).
2) Commercial paging.
3) Communications that run through an AMI system.

Outgoing Communication Costs Option 1: Private RF (154 MHz range)

When evaluating scenarios for one-way communication systems, costs are based on the private RF system that is currently in use in New Jersey. Thirty-six towers send out control signals in the 154 MHz range. If the EDCs continue use of the private 154 MHz communications system, the annualized cost of building and maintaining the towers should be included in the cost analysis. Although they are already built, they may need replacement soon if they have a twenty-year life. Including the replacement tower costs will ensure that the C-E analysis includes all potential costs.

It is likely that some costs will be associated with the replacement of the communication towers to maintain a reliable communications interface. As a result, if this technology is to be assessed, some estimate of maintaining this RF communications system is needed. During research done on technology and communication options for this project, four tower installation companies and one independent radio consultant provided the following information along with ball park estimates on the annualized cost of building and maintaining towers.

- Each tower would generally be between 150 to 199 ft tall (cell tower height). Anything over 200 ft needs lights and much more paperwork.
- The tower framework would be between $20,000 and $25,000.
- The foundation and installation would be approximately $15,000 (assuming normal soil conditions, not swamps).
- The site engineering, permits and legal paperwork costs per tower are approximately $10,000.
- The transmitter and RF amplifier would be between $2,500 and $5,000 for hardware, shack and installation.
- Total capital cost around $50,000 per tower (this does NOT include the land).
- The tower's minimum lifespan is 20 years. Towers can last much longer.
- The tower should be inspected at least every three years ($500 per inspection).
- Amortized over 20 years, costs are approximately $4,900/year per tower.
- These costs do not include the data pipeline from the utility to the tower, nor the control software at the utility.
- A utility has the option to rent out tower space to other wireless providers. The going rate is $2-$3 per foot (of tower height) per month.
- Leasing space for one antenna can bring in revenue of $3,600 a year, which would more than cover the cost of the tower. More antennas require a stronger tower because of the wind force on the antennas. Southern California Edison leases their tower space out to other companies. (The cost-effectiveness analysis did not assume any lease income for renting tower space.)

The New Jersey EDCs use their towers for many communication purposes in addition to sending out direct load control signals. Based on discussions and information requests made to the EDCs, it is estimated that 20% of the cost of the towers should be assigned to the DLC program. Based on this information, the amortized value of $4,900 per year per tower multiplied by 20% ($980) is used as the cost of the towers in the C-E analysis. The total cost used in the one-way communication scenarios for owning and maintaining the tower infrastructure was 36 x $980, or $35,280 per year.

Outgoing Communications Costs Option 2: Commercial Paging (900 MHz range)

Commercial one-way paging is not used in any of the preliminary scenarios since the private radio system already exists. Commercial two-way paging is used for the two-way thermostat scenario. This option covers incoming and return communications in a single solution. Use of this service costs $1.20 per device, per month, based on thermostat manufacturer information. This cost estimate corresponds with data from utilities that use two-way commercial paging and report a cost of $15 per device per year. The per-message cost of sending outgoing pages for control events does not need to be quantified since it is small. One paging message can control many switches and the cost of one page is 9 cents.

Outgoing Communication Costs Option 3: Use of an AMI System

It is possible to use some AMI systems for sending out control messages. The capabilities and costs vary by type of AMI system. None of the scenarios in this analysis used AMI for sending out control messages.

5.9 Return, Inbound Communications Costs

There are a variety of options for return communication systems. Each communication option, together with the control device it is working with, offers its own unique set of features that affect the costs and design possibilities of the load control program.

The information available to be returned is dependent on the information that is collected by the control device. Different control device types collect different information and in different ways. While many variations are possible through custom engineering, each device type has a set of information that is typically collected.

Switches collect a small amount of cumulative information in a few different data 'buckets'. Each bucket can hold one piece of information. The typical types of information collected in buckets are: elapsed time since reset, total AC run time since reset, total prevented AC run time since reset, and date/time of the last control signal received.

Thermostats can collect and store more data. Instead of storing a few cumulative data points ('buckets'), they can store hourly data for weeks or months. The hourly data typically includes a time stamp addressing at least the date and hour, the AC run time during the hour, prevented AC run time during the hour, receipt of control instructions, temperature settings and actual indoor temperature.

AMI meters can collect hourly information on whole house energy use. Table 5-6 compares these three sets of typical information available from each device.

Table 5-6. Data Typically Available by Device Type

SWITCH (single data points)	THERMOSTAT (hourly data points)	AMI METER (hourly data points)
Elapsed time since reset	Date and Hour	Date and Hour
Actual AC run time since reset	AC run time each hour	Whole House Energy Use
Prevented AC run time since reset	Prevented AC run time each hour	
Date/time of last control signal received	Date/time of all control signals received	
	Temperature Setting each hour	
	Actual Indoor Temperature each hour	

Source: Derived from interviews with manufacturers and vendors, March 2007

All of this information is available within the individual devices, but collecting it into a central database can be expensive. There are several ways to collect this information: 1) send a person out to each site (which may or may not necessitate an appointment and access to equipment inside the house), 2) two-way paging, 3) telephone line, 4) cellular, 5) AMI system or 6) Internet. Each of these methods offers different possibilities for program costs and features.

Information on received control messages and prevented run times can help with detection of failed switches. This information can help target maintenance to reduce maintenance costs and keep the load impacts of the system from degrading over time.

Information on received control messages allows counting the number of overrides taken by the customer. This allows the program design to put a limit on the number of overrides, or attach a penalty/reward to the number of overrides. It is necessary to collect this information in a return communication system if the override is performed at the site by the customer pushing an override button. If the override is performed through a Web site, it is possible to monitor overrides through the Web site without a return communication system. If the number of overrides is attached to a reward or penalty that will appear on the bill, extra steps will have to be taken to get the Web-based information into the billing system.

Information on run times and prevented run times is useful for measurement and verification of the load impacts of the system. Additional information on the size of each AC unit would also be useful. Collecting run time information through a return communication system could decrease data collection costs for M&V efforts and allow larger samples. This would increase the reliability of the load impact estimates.

Information on whole house energy use would be needed if the incentives for the load control program were tied to a TOU, CPP, or a real-time pricing rate.

Table 5-7 describes the required infrastructure and the communication speed of each of the possible return communications methods. These two factors, coupled with the type of control device in use (switch or thermostat), define the potential applications that would be possible with the given return communication method.

Table 5-7. Features of Return Communications Methods

Method	Required Infrastructure	Communication Speed	Potential Applications							
			Detect Failed Devices		Count Overrides		Measure Run Times During Control		Measure Load During Control	
		(S = switch, T = thermostat) →	S	T	S	T	S	T	S	T
Site visit	Regular control device, person, vehicle, access to device which may be inside or outside, PDA to download data	As many sites as a person can visit in one day times the number of people on the task	S	S		S		S		
Two-way Paging	Two-way paging control device, commercial two-way paging tower within range (service costs approximately $15/device/year, plus 9 cents per message)	100 to 200 sites per minute	P	P	F	P	F	P		
Telephone Line	Regular control device, phone module to connect device to phone (wired or wireless), permission to use customer's land phone line (additional cost of module is in the $100-$200 range)	Central phone line to collect information, receives calls one at a time; speed estimated at less than 2 sites per minute depending on size of data packets	S	S	F	S	F	S		
Cellular Telephone	Regular control device, module to connect device to cellular communications (additional cost of module is in the $300-$400 range, service costs approximately $6/device/month)	Speed similar to Telephone	S	S	F	S	F	S		
Internet	Internet-capable control device, broadband Internet in the home, wireless router (cost of router is in the $50-$100 range, high speed server on the data collection side is approximately $1000 per month)	100,000 sites per minute *(Note: CAT5 Internet-capable thermostats are currently available. Wireless Internet-capable thermostats are scheduled for availability in Fall 2007.)*	P	P	F	P	F	P		
AMI	Regular control device, module to connect device to AMI communications, AMI meter and communication system	Speed varies by type of AMI system; collecting load data for billing will always be first priority, unused bandwidth is available for returning control device information	P	P	F	P	F	P	P	P

Explanation of Colors and Symbols:
Gold: P = *Population; data availability, costs and communication speeds make it possible to use on all program participants*
Yellow: S = *Sample; the expense or the speed make this more appropriate for collecting information on a sample of participants*
Blue: F = *Frequent polling required; since data is cumulative, frequent and well-timed polling would need to be done after each control event*
Blank = *not a feasible option*

Source: Based on interviews with manufacturers and vendors, March 2007.

Site visits, telephone lines and cellular communications are the slowest and most expensive ways to collect return information. They work best for collecting information on samples of participants, rather than on all participants.

Two-way paging, Internet and AMI are best for communicating with all program participants. AMI systems have the added benefit of being able to return information on energy consumed during control periods. This is necessary if a TOU, CPP or rebate is part of the load control program design. (Note: it is also possible to use a TOU bucket meter or an interval meter to support these rates, but historically these meters have been too expensive to use as part of a load control rate design for small customers, so they are not considered in this analysis.)

From a technical perspective, switches can be paired with any return communication system. However, because of the limited nature of the information collected in switches, this is not usually done. Even though it is not usually done, the possibility of collecting information from the switches was included in the comparison table to make sure low-cost opportunities are not being overlooked. Since the switch usually holds information on the last control message received, it would be possible to detect failed switches through a return communication system. Counting overrides and measuring run times during each control event would require frequent polling of the bucket data. Reset commands would have to be sent before each control event, and data collection would have to take place and be concluded before the next control event. This is possible, but would require constant and careful attention.

There are many return communication systems to choose from. We included in the C-E scenarios the two that have been implemented most often (site visits for one-way switches or thermostats and two-way paging for thermostats) plus the AMI solution. Table 5-8 compares the costs and program effects related to these return communication system options. Details on the individual items in the table follow.

Table 5-8: Costs and Effects of Return Communication Systems used in the Cost-effectiveness Scenarios

	Site Visits For One-way Switches or Thermostats	Two-way Paging For Thermostats	AMI System Added to Switches or Thermostats
Detection of Failed Devices	$25/device/year	$15/device/year	$2.50/device/year
Replacement of Failed Devices	$5/switch/year or $10/thermostat/year	$10/thermostat/year	$5/switch/year or $10/thermostat/year
Effect on Load Impacts	12.5% degradation	No effect	No effect
Ability to Monitor Customer Overrides	Do not allow overrides because they cannot be monitored.	Allow 1 override per summer and monitor compliance; Each return page costs 9 cents; Seven events would cost $0.63/device/year	Allow 1 override per summer and monitor compliance; could offer rate-based incentives or penalties (TOU, CPP, RTP)
Measurement & Verification Costs	$50,000 per year	$10,000 per year	$10,000 per year

Source: Summit Blue interviews with manufacturers and vendors and secondary research. May 2007.

The subsections below discuss the costs and effectiveness of using different methods to obtain return data from the switch or thermostat. They are placed into three groups – 1) site visits; 2) commercial paging; and 3) AMI systems. The outbound communications can use the existing RF systems at the EDCs, but it is not practical to transmit information from the control device back to the utility through the same system. Control devices operate at such low wattages, generally from 0.10 to 0.25 watts, that they are incapable of sending out a strong enough signal to be received by a radio tower that is far away.

Return Communications: Option 1 – Costs and Effectiveness of Site Visits

Xcel-Minnesota studied their costs for maintaining switches with a regular site inspection program. They found that one-third of their switches failed after 13 years in the field. This can be due to weather, customer or contractor tampering or removal, or old age. It cost them $600 to find and recover one kW. This number can be annualized per switch. Their average load impact at 50% cycling is reported as 1 kW per switch. Assuming a 20-year life for switches, this works out to an average detection cost of $25 per switch per year and a replacement cost of $5 per switch per year.[19]

This cost for maintenance of devices through manual inspection was verified by data from Sacramento Municipal Utility District. They require a staff of 30 full-time technicians to maintain 90,000 switches. At a fully-loaded technician cost of $75,000 per year, this equates to $25 per switch per year.

Even at this level of inspection, there will still be degradation in the load impact per customer. If the expected lifetime of a device is 20 years, five percent will fail each year on average. (Failures may come closer to the end of the period than the beginning, but a uniform distribution of failures across years will be assumed for simplicity in this calculation. This assumption is also justified since failures may occur before the end of normal lifetime due to weather or tampering.) After five years, 25% will have failed. Since they failed at different times during those five years, the average time each one was in a failed condition is 2.5 years, or half of the inspection period. Under a five year inspection program, each device will spend 2.5 years out of its total lifetime of 20 years in a failed condition. This will reduce program impacts by 2.5 / 20, or 12.5% per year.[20]

One-way thermostats would require the same level of site inspections to maintain the system. While they do not suffer the outdoor elements like switches and they are less likely to be in a failed state, there is no guarantee that they remain installed after the initial installation. When new air-conditioners are put in, thermostats are often replaced and the utility would have no knowledge of that. In the C-E studies, the cost of site inspections for one-way thermostats will be considered equal to one-way switches. Individual site visits will be more expensive for thermostats because of the need to get into the home to check them, but they can be done less frequently because of the lower failure rate. Assuming a 20-year life for thermostats, average detection costs will match that of switches at $25 per thermostat per year but replacement costs will be higher at $10 per thermostat per year because of the higher cost of thermostats. Because of the lower failure rate of thermostats, the load impact adjustment for non-working switches will be half that of switches (6% instead of 12.5%).

Another application for return communications is to verify the load impact. Without a return communication system, data loggers must be put on a sample of customers to estimate load impacts. In *A Regional Model for Estimating Load Impacts of Active Load Management/Direct Load Control Programs*, RLW Analytics and Lawrence Berkeley National Laboratory state that a Public Utility Regulatory Policy Act-compliant (PURPA)-compliant load impact study would cost $250,000 and it must be done every five years in New Jersey. This is equivalent to $50,000 per year and assumes that all the New Jersey EDCs would participate in one study.

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[19] Source: E-source Report EDRP-F-8, "Best Practices in Residential Direct Load Control Programs", November 2006.

[20] Source: This method of evaluating the cost of failed switches is derived from work done by Frank M. Hyde for Sacramento Municipal Utility District.

Return Communications: Option 2 – Costs and Effects of Two-way Paging Systems

In a two-way paging thermostat, each return page currently costs approximately 9 cents. Each device must send an individual page back to the utility. If verification information is needed for seven control events over a summer, this communication would cost approximately 63 cents per device per year.

It would not be necessary to get return information from all seven events if the only purpose of the communication was to verify the working condition of the thermostat. A sample of events could be used to get that information.

However, return communication would be needed from all seven events if customer overrides were being counted or monitored. Giving participants' opportunity to override control events has shown 20 to 30% reductions in load impacts in several pilot programs. To preserve load impacts, new thermostat programs typically either limit the number of overrides allowed, or provide the customers with an incentive not to override. Since limiting the number of overrides is important to maintain impacts, a limit of one override per summer is proposed for the scenarios with two-way communications being considered in the C-E analyses for New Jersey. Counting overrides would require a return page for each control event. Note: The central paging receipt system can only process 100 to 200 return pages per minute, so adequate time must be allowed for complete data collection. At 200 return pages per minute, it would take 23 hours to collect all of the return pages from 275,000 customers.

Information on run times could be collected to reduce most of the data collection costs related to the M&V effort. This could reduce M&V costs by 80%, from $50,000 per year to $10,000 per year.

Return Communications: Option 3 – Costs and Effects of AMI System

Alternatively, return communications could come from an AMI system. Two of the C-E scenarios examine results if an AMI system is added five years after one-way switches or thermostats have been installed. The cost of the AMI system is not included in these C-E scenarios since the AMI system would not be put in specifically for the load control program. However, the cost of adding the required communication module to make the one-way device talk to the AMI system is included.

There are actually two ways to use an AMI system to get information back on a DLC program. One way is to get complete information from the thermostat communicated back to a central location through the AMI system. This requires additional communication modules being added to the control device. The other way is to forego communicating with the thermostat directly, and instead rely on hourly whole-house energy readings from the AMI meter to help identify non-working switches. The first method provides information on non-working switches, overrides and load impacts based on run times. The second method can only provide evidence of working switches and statistical estimates of load impacts. However, this information can be inexpensive to collect and useful for reducing the costs of maintaining DLC programs. Since switches store much less information internally than thermostats do, it can make sense to use the whole-house metering method with switches.[21]

[21] The use of whole house metering through an AMI may be good for identifying switches that likely are not working through a test where a signal is sent to all the switches calling for 100% curtailment, but only for 15 minutes. The impact of this level of control can usually be seen on a whole house meter if performed on a reasonably hot day and if the AC is on. If some AC units are off due to setback strategies or vacations, they may also be shown as non-working switches. As a result, this approach identifies candidate non-working switches. Formal impact evaluation of the program may still require a sample of end-use meters placed on the AC compressor to

Xcel used the whole-house metering method to help identify non-working switches in their service territory. By using this method, Xcel reports that their costs to detect and recover failed switches dropped by 75%, from $600 per kW to $150 per kW. On an annualized basis, this reduces detection costs from $30 per switch per year to $7.50 per switch per year. An added benefit is that the switches can be tested annually instead of once every five years. The average load impacts will not be degraded with this method.[22]

As mentioned previously, an AMI system could be used to communicate directly with a control device to monitor overrides and reduce measurement and verification costs. The C-E scenarios assume these features would be used for thermostats to enforce a limit of one override per summer and reduce M&V costs by 80%.

5.9.2 Marketing Costs

Two types of marketing costs are included in the C-E scenarios. One is the customer acquisition cost (the cost of attracting and signing up initial participants). The second is the cost required to maintain participation in a home with a control device after the original participant moves out.

Xcel Energy reports a customer acquisition cost of $70 per participant.[23] This value is used across all the C-E scenarios.

All load control programs experience some turnover in participation (churn) and annual reductions will result unless processes are in place to enroll replacement participants. As customers move out of a home with a control device, the new homeowners need to be enrolled into the program to maintain participation rates. Data from JCP&L shows that the number of participating customers in their service area turned over by 8% over four years, from 2002 to 2006. An annual turnover rate of 2% will be used in the C-E scenarios. A cost of $10 per customer will be used to cover the cost of finding and contacting replacement customers. This represents the cost of maintaining a system to identify and send program invitation letters to new homeowners. They will each receive a $50 sign-up incentive to participate in the program.

5.9.3 Program Administrative Costs

Data was received from both PSE&G and JCP&L on their annual fixed administration costs for their current AC DLC programs. This annual fixed cost is estimated to be $300,000 per year for each utility. While their actual program budgets are higher than that, costs related to the maintenance of the devices were removed because they are covered separately in the C-E tests. Total program administration costs for all three EDCs are estimated to be $900,000 per year.

Start-up costs are higher in the first year when processes and systems have to be developed for the new program. These start-up costs include billing system enhancements, call center training, HVAC

isolate the impacts at the unit level. Whole house data can show changes in energy use due to factors other than the AC unit as people return home in the evenings, and turn-on televisions, computers and other electrical devices. This can result in whole-house meters showing a degradation in impacts over the 4 pm to 7 pm period within a control event, thereby underestimating the impacts of the AC program, i.e., the AC program is still providing the same level of impacts.

[22] Source: E-source Report EDRP-F-8, "Best Practices in Residential Direct Load Control Programs", November 2006.

[23] Source: E-source Report EDRP-F-8, "Best Practices in Residential Direct Load Control Programs", November 2006.

contractor/installer network development and training, control system testing and integration with system operating procedures. Start-up costs are estimated to be twice the regular annual program administration costs, or $600,000 per utility for the first year ($1,800,000 total).

5.9.4 Summary—Estimated Investment

All of the C-E scenarios assume a five-year installation schedule resulting in a target of 17% penetration of the program among residential customers with central AC, and an additional increment of small business customers that can use the same technology. The first year has more modest participation rates than the remaining years to allow for ramping up activities. This still is an aggressive schedule, particularly for the first two years of the program when design assumptions are being validated through ongoing customer research. This schedule requires that the technologies that form the basis of the program be proven and ready for immediate application without foreclosing future options that might improve the programs as the technologies continue to advance. The rate of converting existing participants from the legacy program to the new program was assumed to be constant after the first year, which also implied an assumed sign-up rate for new participants that is also constant after the first year. In practice, these rates may vary due to the success of the marketing messages and efforts. As a result, the EDCs may vary from this pattern as they fine tune their marketing efforts and field work.

These installation years require annual investments beyond what will be needed to maintain the program after the first five years.

Table 5-9 identifies the estimated investment dollars that will be needed for each different scenario. Note that Scenarios B and D do not include investment dollars that would be needed for the AMI system.

Table 5-9. Investment Estimates fo r Early Program Years (all costs are in thousands of dollars)

	2008	2009	2010	2011	2012	2013
New Device Installations[24]	33,480	65,880	65,880	65,880	65,880	0
Transfer Legacy Participants[25]	27,000	48,000	48,000	48,000	48,000	
New Participants	4,000	14,000	14,000	14,000	14,000	
Cumulative Participants	31,000	92,000	153,000	214,000	275,000	275,000
Scenario A - Switches						
Equipment and Installation Costs	$7,700	$15,152	$15,152	$15,152	$15,152	$0
System Maintenance Costs	$0	$1,004	$3,058	$5,249	$7,576	$10,045
Program Administration Costs	$4,055	$5,285	$5,315	$5,347	$5,379	$1,142
Cash Incentives	$770	$2,285	$3,801	$5,316	$6,831	$6,831
TOTAL	$12,526	$23,727	$27,327	$31,064	$34,938	$18,018
Scenario B - Switches with AMI Added in 5 Years						
Equipment and Installation Costs	$8,705	$17,129	$17,129	$17,129	$17,129	$0
System Maintenance Costs	$0	$1,004	$3,058	$5,249	$7,576	$10,045
Program Administration Costs	$4,055	$5,285	$5,315	$5,347	$5,379	$1,142
Cash Incentives	$770	$2,285	$3,801	$5,316	$6,831	$6,831
TOTAL	$13,530	$25,703	$29,303	$33,040	$36,914	$18,018
Scenario C - Thermostats						
Equipment and Installation Costs	$10,044	$19,764	$19,764	$19,764	$19,764	$0
System Maintenance Costs	$0	$1,172	$3,601	$6,179	$8,915	$11,818
Program Administration Costs	$4,055	$5,285	$5,315	$5,347	$5,379	$1,142
Cash Incentives	$1,674	$3,294	$3,294	$3,294	$3,294	$0
TOTAL	$15,773	$29,515	$31,975	$34,583	$37,352	$12,960
Scenario D - Thermostats with AMI Added in 5 Years						
Equipment and Installation Costs	$11,048	$21,740	$21,740	$21,740	$21,740	$0
System Maintenance Costs	$0	$419	$1,158	$1,994	$2,887	$3,839
Program Administration Costs	$4,055	$5,285	$5,315	$5,347	$5,379	$1,142
Cash Incentives	$1,674	$3,294	$3,294	$3,294	$3,294	$0
TOTAL	$16,778	$30,738	$31,508	$32,375	$33,300	$4,981
Scenario E - Thermostats with Automatic Return Communication						
Equipment and Installation Costs	$14,229	$27,999	$27,999	$27,999	$27,999	$0
System Maintenance Costs	$0	$356	$955	$1,646	$2,386	$3,176
Program Administration Costs	$4,522	$6,739	$7,756	$8,775	$9,794	$5,556
Cash Incentives	$1,674	$3,294	$3,294	$3,294	$3,294	$0
TOTAL	$20,425	$38,388	$40,005	$41,714	$43,473	$8,732

Source: Summit Blue analysis

[24] Participants will typically have more than one device if they have more than one compressor so the total number of devices is larger than the number of participants.

[25] Legacy participants are those who are currently enrolled in the EDC's legacy AC load control programs.

6. RESULTS OF COST-EFFECTIVENESS (C-E) ASSESSMENTS

This section presents the results of the C-E analysis using two approaches. The first approach is based on a standard spreadsheet model used to calculate the Total Resource Cost Test (TRC) and the Rate Payer Impact (RIM) test. The second approach uses the DSMore model available from Integral Analytics, Inc. and used by Duke Power and other utilities for C-E analyses. This model has a market price forecasting module integrated into the analysis that can help examine future prices in PJM and it also has a Monte Carlo capability that allows for the development of high price days.

Both approaches focus only on the direct resources savings (avoided capacity and energy costs) and do not consider indirect impacts often attributed to demand response programs such as: 1) reduced market power, 2) reduced prices for all market participants, 3) potential reliability improvements due to a more diversified resource portfolio, and 4) customer benefits that may result through more control over their energy costs (particularly for thermostat-based programs).

Early in the project it was viewed as useful to benchmark the results using these two different analytic approaches. The first section presents the results from the standard deterministic spreadsheet approach to estimating the TRC and RIM for each option. The second section presents the results generated by DSMore.

6.1 Results of Cost-Effectiveness Assessments – Spreadsheet Model

Both the TRC test and the RIM test were estimated for all five technology scenarios using a traditional spreadsheet model. There is a discussion that is on-going about whether incentives to participants should be treated as transfer payments or should be treated as program costs. This is further complicated when the incentive is a piece of equipment (e.g., a free thermostat). In some jurisdictions, equipment is not allowed to be counted as an incentive even if this equipment incentive is less than the streams of cash or bill incentives paid annually for an AC DLC program. Some utilities have avoided this debate by offering customers a cash sign-up bonus that just happens to approximately equal the cost of a thermostat thereby avoiding the debate over whether cash is the only incentive-type that is allowed to be treated as a transfer payment. When incentives are treated as program costs, they only appear in the denominator and thus reduce the benefit/cost ratio. When incentive payments are treated as transfer payments from all customers to participants, these two factors net each other out when assessing cost-effectiveness from a total resource cost perspective (as generally defined). The TRC test generally treats incentives as transfer payments, while the ratepayers impact test (RIM) does not. The RIM test is supposed to be used as a check to ensure that the incentives, when viewed as transfer payments,[26] are not inequitable. While there was some discussion among the parties regarding whether a free thermostat can be viewed as an incentive or not, the purpose of the RIM test is to check on the reasonableness of the dollar value of incentives regardless of whether the incentives are cash payments or an incentive in terms of a free thermostat.

[26] It would seem logical that the total value of incentives should be the variable of interest. The reason some utilities have offered free thermostats as an incentive is that seems to provide a more tangible benefit to customers, and it is less expensive that providing cash incentive payments to customers every year. It does not seem appropriate to penalize a program strategy via the TRC test when the program costs less to implement than another program strategy. However, there were some strong opinions on this topic. As a result, some utilities pay the customer a sign-up bonus of $250 instead of installing a free thermostat which is assumed to have similar costs.

Rather than get tied down in this debate, the assessment examined the TRC results from both perspectives – all incentives viewed as transfer payments and all incentives (including the cost of the thermostat even when offered as an incentive) as costs. These are the bounding cases with the latter being very close to the RIM test and essentially taking a point of view similar to the RIM test. It turned out that the choice of perspective did not substantively alter the program economics as can be seen in the analyses below.

All of the tests for all of the scenarios were estimated twice using different avoided capacity cost values, $65 per kW per year and $100 per kW per year (See Section 5.1). This provides a range of cost-effectiveness for decision-making in the face of an uncertain future.

Results show that all scenarios pass all tests at both avoided capacity cost levels. Scenario A (switches with no AMI) has the lowest benefit-cost ratios tests. The most cost-effective scenario is Scenario D (Thermostats with AMI), but it must be remembered that no costs for the AMI system itself are included here.

Table 6-1. Results of Cost-Effectiveness Tests – Spreadsheet Model

Scenario	MW Impact	Total Resource Cost (TRC) Benefit/Cost Ratio *(with incentives as transfer payments)*	Total Resource Cost Benefit/Cost Ratio *(with incentives treated only as program costs)*	Rate Impact Benefit/Cost (RIM) Ratio
(A) Switch with **no change** to automated return communication in the future through AMI	303	1.6 to 2.2	1.2 to 1.6	1.2 to 1.6
(B) Switch with automated return communication through the meter when **AMI** is in place	349	2.3 to 3.3	1.6 to 2.3	1.5 to 2.2
(C) Thermostat with **no change** to automated return communication in the future through AMI	303	2.0 to 2.9	1.2 to 1.7	1.1 to 1.7
(D) Thermostat with automated return communication through the meter when **AMI** is in place	322	4.3 to 6.3	1.7 to 2.5	1.6 to 2.4
(E) Thermostat with current automated return communication capability	322	2.9 to 4.2	1.2 to 1.8	1.2 to 1.8

Note 1: The ranges show the difference in test results when avoided capacity is valued at $65 per kW per year and $100 per kW per year.
Note 2: Thermostats are treated on the same footing as other customer incentives in all scenarios.
Note 3: Scenarios (2) and (4) do not include costs for the AMI system itself.
Source: Analysis by Summit Blue Consulting, May 2007

Each scenario is based on expected participation of 275,000 residential customers. This is a 17% participation rate from eligible customers with central air-conditioning in the current RF communication coverage areas in PSE&G, JCP&L and ACE service territories in New Jersey.

6.2 Load Reductions

The expected MW load reductions are lowest for Scenarios A and C.

Scenario A is low because each switch is inspected only once every five years. Switches may be in a failed state for several years before detection and repair. This de-rates the load impacts from the program.

Scenario C is low for two reasons. First, it is similar to Scenario A in that the manual method used for detecting failed switches de-rates the load impacts. However, since thermostats are not exposed to the outdoor elements and they are in sight and used by customers frequently, they are less likely to be in a failed state than switches are. The most likely problem with a thermostat is that a regular thermostat gets installed when the AC unit is replaced. To account for these factors, the de-rate is only half of the switches. However, the thermostat program design allows customers to override once a summer. This override factor adds additional de-rating to the load impact. The combined effect of non-working thermostats and overrides creates an overall load impact equivalent to switches in Scenario A.

The expected MW load reductions are highest for Scenario B since overrides are not allowed in the switch programs as designed for these scenarios, and the addition of an AMI system minimizes the number of non-working switches.

The expected MW load reductions are in the middle range for thermostat scenarios D and E. Both of these scenarios minimize non-working switches, but customers are allowed to override once per summer.

6.2.1 TRC Benefit-Cost Results

Scenario D, thermostats with AMI, has the highest TRC test score. This is largely due to the fact that the maintenance costs decline and the achieved impacts rise when AMI starts. As with the other thermostat scenarios, the thermostat itself is part of the incentive to the participant. The purchase and installation costs for the thermostats are netted out of the equation from the societal perspective, and these are significant program costs.

The other thermostat programs would also be expected to have high TRC test scores for the same reason. They are also high, but tempered by other significant costs. Scenario C, thermostats with no AMI, has high costs for a manual inspection program. Scenario E, the thermostat with current automated return communication capability, has the highest device purchase and installation costs of all the scenarios, plus high on-going communication system costs.

Since incentive costs are a significant portion of both the switch and thermostat programs, it is informative to look at the results of the RIM test which includes incentive costs. In this study, the results of the RIM test are very similar to results obtained from the TRC test when incentive costs are included. They are similar because there is little energy reduction in an AC DLC program and lost revenues are very small.

6.2.2 RIM Benefit-Cost Results

The RIM test results indicate that Scenario D, thermostats with AMI has the highest cost-effectiveness ratio, just as in the TRC test. This makes sense since the cost of the AMI system is not included as a cost of the DLC program. If the AMI system is available, it will be there primarily to serve other purposes. Serving the DLC program is an additional use of the AMI system that will not add costs to the AMI system. However, additional communication equipment for the control devices to communicate with the AMI system are an additional cost and these costs are already included in the scenarios.

It is possible to get a rough estimate of the value that an AMI system would add to a DLC program. This is useful for developing a business case for an AMI system. The annual cost to keep all devices in working condition will drop from approximately $30 per device per year to $7.50 per device per year.

The RIM test results for scenario B is also close to scenario D because of the savings from use of the AMI system. The other scenarios (A, C and E) have RIM test results that are similar to each other. They are all less than RIM test results for Scenarios B and D. The high costs to detect and repair failed equipment when no AMI system is available keeps scenarios A and C low, while high equipment purchase and installation costs as well as high communication costs keep test scores lower in Scenario E.

6.2.3 Summary – Spreadsheet C-E Analysis of Benefits and Costs

All of the cost-effectiveness tests were run for residential customers only, although the equipment and program designs tested in the scenarios could also be made available to small commercial customers.

The biggest difference between residential and small commercial customers in an AC DLC program is the size of the individual customer load impacts. Small commercial customers tend to have larger AC systems which create greater program benefits for the same costs. This is why several utilities, like Consolidated Edison and Southern California Edison, put special emphasis on promotion of their AC DLC programs to small commercial customers.

Similar costs and greater benefits mean that C-E results will be better for small commercial customers than for residential customers. To make efficient use of the time available to do this study, all effort was concentrated on modeling residential participation with the assurance that results for small commercial participants would be similar or better. Decisions can be made on the residential results alone. Including small commercial customers in the actual program will only improve the cost-effectiveness.

The following table provides more detail on the results of the C-E study and the inputs used for each scenario.

Table 6-2. Benefit/Cost Summary

SCENARIO	A. Switch with no change to automated return communication in the future through AMI	B. Switch with automated return communication through the meter when AMI is in place	C. Thermostat with no change to automated return communication in the future through AMI	D. Thermostat with automated return communication through the meter when AMI is in place	E. Thermostat with current automated return communication capability
Technology Description	Switch with adaptive algorithm; Private RF paging communication	Switch with adaptive algorithm and an AMI-compatible communications port	Programmable thermostat; Private RF Paging communication	Programmable thermostat with an AMI-compatible communications port	Programmable thermostat with Commercial Paging communication each way (900 Mhz range)
BENEFIT/COST RESULTS					
MW Reduction at System Peak	328	377	327	347	347
Total Residential Participants Statewide	275,000	275,000	275,000	275,000	275,000
BENEFITS - 15-yr NPV					
Avoided Capacity Costs @$65/kw/yr (millions)	243	257	222	236	236
Avoided Capacity Costs @$100/kw/yr (millions)	343	394	342	363	363
Avoided Energy Costs (millions)	29	33	28	30	30
COSTS - 15-yr NPV					
Program Costs without Incentives (millions)	171	128	127	62	93
Incentives (millions)	57	57	89	97	121
Lost Revenues (millions)	7	8	7	7	7
@ $65/kw/yr Avoided Capacity Costs:					
Total Resource Test (with incentives as transfer payments)	1.6	2.3	2.0	4.3	2.9
Total Resource Test (with incentives only as costs)	1.2	1.6	1.2	1.7	1.2
Rate Impact Test	1.2	1.5	1.1	1.6	1.2
@ $100/kw/yr Avoided Capacity Costs:					
Total Resource Test (with incentives as transfer payments)	2.2	3.3	2.9	6.3	4.2
Total Resource Test (with incentives only as costs)	1.6	2.3	1.7	2.5	1.8
Rate Impact Test	1.6	2.2	1.7	2.4	1.8
MAJOR INPUTS					
Avoided Capacity Cost	Same for all scenarios: $100 per kw per year; 100% applied to single summer peak hour				
Avoided Energy Cost	Same for all scenarios: 43 cents per kwh during control periods; 16 cents per kwh during snapback hours after control				
Cycling Strategy	Same for all scenarios: 50% cycling for 28 hours; usually spread over 7 days				
KW reduction per device before adjustments	1.1	1.1	1.1	1.1	1.1
Adjustment for non-working switches	-0.14	0	-0.07	0	0
Adustment for overrides (allow one per year)	0	0	-0.08	-0.08	-0.08
Adjustment for Reserve Margin	0.14	0.17	0.14	0.15	0.15
KW reduction per device after adjustments	1.10	1.27	1.09	1.17	1.17
Annual KWH reduction per device during control periods	27	31	27	28	28
Annual KWH increase per device during snapback periods	13	15	13	14	14
Incentive	$4 per month for four months, plus $1 per event; assume 7 events for $23 per customer per year	$4 per month for four months, plus $1 per event; assume 7 events for $23 per customer per year	Free thermostat installed plus $50 sign-up bonus	Free thermostat installed plus $50 sign-up bonus	Free thermostat installed plus $50 sign-up bonus
Participation Rate	17%	17%	17%	17%	17%
Equipment Cost per Device	$100	$130	$200	$230	$225
Labor Cost to Install Device	$130	$130	$100	$100	$200
Annual cost to keep all devices working (detect & replace)	$30/device/year	$7.50/device/year	$35/device/year	$12.50/device/year	$10.63/device/year
Annual cost for communication system	$19,440	$19,440	$19,440	$19,440	$15/device/year
Annual Labor Costs	Same for all scenarios: $1,800,000 in start-up year, $900,000 per year during program life (includes engineering, administration, call center and database)				
Marketing Costs	Same for all scenarios: $70 per participant for acquisition costs, 2% drop-outs per year, $10 per participant for replacements				
Measurement & Verification Costs	$50,000 per year	$10,000 per year	$50,000 per year	$10,000 per year	$10,000 per year

Note: More detail on development of the inputs can be found in Appendix B.

Exhibit D
Attachment 5

6.3 Results of Cost-Effectiveness Tests - DSMore Model

The spreadsheet method of Section 2.1 estimates cost-effectiveness for the AC DLC scenarios using simple assumptions about the future. It assumes that in future years the weather will always be normal, load impacts will always be the same, and real energy costs will be just what they were in 2006. In reality, though, we know that weather varies across a range of highs and lows. Some summers will have extremely hot weather which will cause air-conditioners to have longer run times, putting higher loads on the electric system. Higher loads will cause higher prices.

This variability is particularly important when evaluating the cost-effectiveness of an AC DLC program. Since hot weather causes both increased loads and increased prices at the same time, there is a covariance effect that makes the value of AC DLC programs very high for a small number of extreme weather events which are likely to occur at some point. We need a method to predict and capture the avoided cost benefits of these extreme events. DSMore is a modeling tool that can do this.

6.4 Introduction to DSMore

The DSMore model[27] was created for the primary purpose of evaluating the value of energy efficiency and demand response programs under market-based electric prices. It is based on several underlying statistical models that work together to provide probabilistic assessments of the impact of future electric markets on the value of energy efficiency and demand response programs. Importantly, DSMore develops probabilistic based estimates of future loads and market prices which allows the assessment of an AC DLC program in the context of potential extreme weather days and seasons.

DSMore starts with a unique Causal Simulation methodology that models hourly customer loads using optimally-selected, non-linear regression equations for each month and day type. These models relate hourly load savings to temperature, humidity, year, wind speed, interaction effects and other potential factors. Optimally selected weather response functions are used to forecast and simulate the customer's usage over varied hourly weather conditions, leading to a wide specification of possible DSM load savings over 30+ years of possible weather scenarios.

Hourly forward market price forecasts are built using weather-based conditional GARCH time series models[28]. GARCH models are used within the energy planning community to express and value the daily and hourly expectations of forward energy costs, and hence potential avoided costs for demand side measures.

The GARCH based price forecasts are simulated through the same hourly weather patterns that are used for the load savings forecasts, insuring that an hour by hour alignment of prices and loads is established. This process insures that the hourly covariance's between prices and loads is measured. By correlating expected future prices and forecasted future load savings through the same set of hourly weather observations, DSMore insures that extreme weather conditions, which will lead to high demand, will also be valued under commensurately high market prices, as we would expect.

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[27] The DSMore model was developed by Integral Analytics, Inc. of Cincinnati, Ohio and has seen its principal use at Duke Power Company, but other utilities and energy organizations are examining the model. It has also been used by Summit Blue in two other utility studies of energy efficiency and demand response programs.

[28] GARCH stands for Generalized Autoregressive Conditional Heteroskedastic, and refers to a special type of regression model which is used in financial modeling.

6.4.1 DSMore – Estimating Avoided Energy Costs

Integral Analytics, Inc. developed load and price forecasts specifically for use in this study. These forecasts are based on New Jersey data from several sources.

- Thirty years of NOAA historical weather data for Trenton was used to model the expected weather highs and lows and their likelihood of occurrence.
- Whole-house hourly load data for residential customers in Ohio was used to develop 576 non-linear regression models of air-conditioning response to weather conditions. The air-conditioning response models were then applied to New Jersey weather data to predict New Jersey residential customers' load response to future weather scenarios at the hourly level. Appendix C provides details on this modeling effort.
- Historical price and load data for the New Jersey PJM market from 1999 to the present was analyzed using a GARCH method to capture the relationship between the two variables. The resulting model was used to estimate a probabilistic range of future expected prices for different weather scenarios. The combination of price ranges and weather scenarios creates approximately 600 different market price/weather scenarios that can be used to evaluate AC DLC programs across all possible futures.

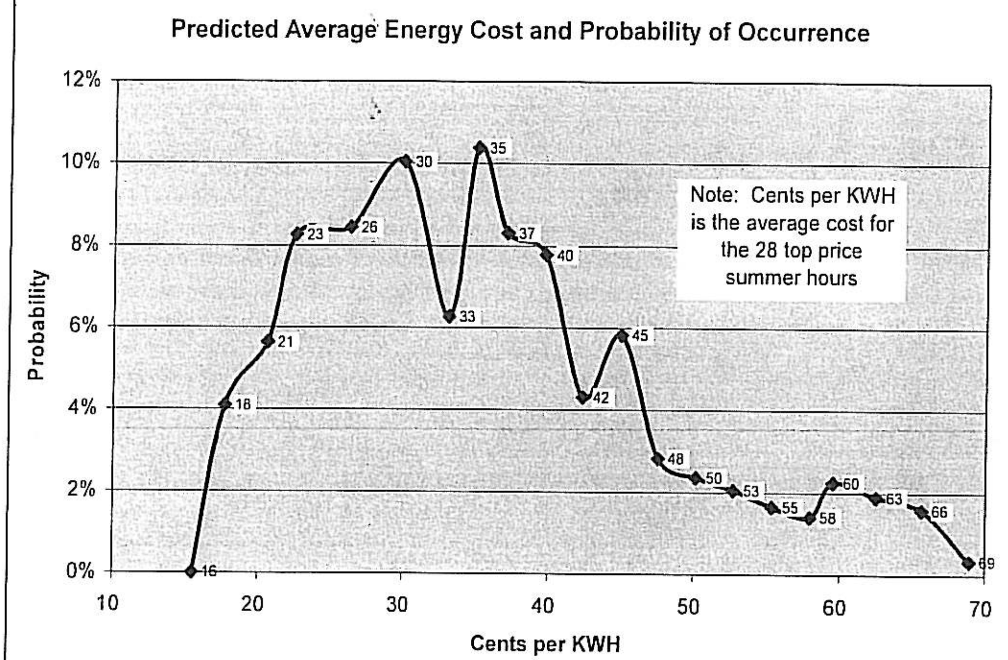
Rather than estimating a single answer to the cost-effectiveness question, DSMore has the data and the computing power to estimate the answers across 700 possible market price/weather scenarios. This gives a full view of the risk related to the volatility of future prices. It is up to the analyst to assess the associated probabilities of these possible futures, which are based on historical relationships, and use them together with information on changing external factors to make an informed decision about likely future prices and the cost-effectiveness of the AC DLC program.

This study is particularly interested in understanding the future market price value of 28 hours of load control each summer. Since the DSMore model forecasts hourly price volatility specifically for the PJM New Jersey market, it is possible to observe the range of calculated average energy prices during the 28 top price hours each summer, jointly over 30+ weather years and 21 forward market price scenarios. The average energy price for the top 28 hours can be calculated for each of the 700 or so market price/weather scenarios, and then assigned a weighting based on the probability of occurrence.

Figure 6-1 shows the range of expected prices and their associated probabilities. These probabilities exhibit the log logistic distribution with an upper skew that is typical of peak electricity market prices.[29] Observations of the historical price data for PJM supports the log logistic pattern used in this study.

[29] Based on the experience of Integral Analytics in working with data from various price hubs.

Figure 6-1. PJM New Jersey Market Predicted Price Volatility for 28 Control Hours



Source: Summit Blue analysis using DSMore model, May 2007

Using the probability weights from this distribution, an expected energy cost can be calculated. This expected energy cost is 36 cents per kWh. This means there is a 50% chance that weather and forward prices will conspire to create market prices below this, and a 50% chance they will be greater than this.

In the spreadsheet C-E model, 43 cents per kWh is the assumed market price for the top 28 control hours. This is based solely on prices seen in 2006. Figure 6-1 illustrates that there is a 25% chance that the market price will reach or exceed 43 cents. Initial consideration would say that the 43 cents seen in 2006 is from the upper end of the distribution and is too high for use as a long-term expected market price in the spreadsheet model. However, additional consideration would alter that judgment.

Because the distribution of forecasted market prices is based on observed relationships found in historical weather, load and price distributions, it is possible to consider conditions by which prices may exceed 43 cents per kWh. There are external factors that may put additional upward pressure on market prices above what is captured in the historical relationships. These factors may indicate that prices above the average may be a more accurate indication of true market behavior. These external factors include:

1) Increasing fuel costs – The cost of electricity during peak demand hours relies heavily on the price of natural gas used in peaking plants. Natural gas futures on the NYMEX market for May 2008 indicate a 6.8% price increase over May 2007. This compares to a general forecast of 3% for inflation, indicating that natural gas prices will rise faster than general prices.[30] Above average fuel costs are the least consequential factor in market price uncertainty, though, compared to the potential impacts of the following three items.

[30] Natural gas futures from http://www.nymex.com/ng_fut_csf.aspx?product=NG, and inflation forecast from http://www.cxoadvisory.com/inflation/#forecast.

2) Transmission congestion – The New Jersey region in PJM has transmission congestion problems which make prices there higher than those seen in the PJM West region. The congestion problem will likely grow faster than the solution, contributing to increasing prices for the New Jersey region. Since this factor is more of a capacity risk than a fuel risk, its consequence can have a more significant influence of the value of demand response programs.
3) Global warming – Global warming may lead to higher average temperatures than what has been seen in the last 30 years. The New Jersey EDCs use only 20 years of past weather data for calculating normals. More consequential, though, than a rise in average temperatures for the valuation of demand response programs is the possibility of realizing higher temperatures during extreme events, as asserted by some researchers.[31]
4) Supply shortage – Projections of low market prices rely on the assumption that markets will build out required capacity efficiently and economically. However, conditions exist in today's markets that may constrain development. These constraints include increasing installed capacity costs, price caps, time lag between construction and operation, and regulatory uncertainty. Being short capacity has perhaps the most consequential impact on the valuation of demand response. In addition, there is a growing concern among generation operators that a shortage in supply is possible as old units that have been continually refurbished are finally forced to retire. Demand response programs realize much of their value during times when system load approaches the capacity limit and power must be purchased in the market at high prices.

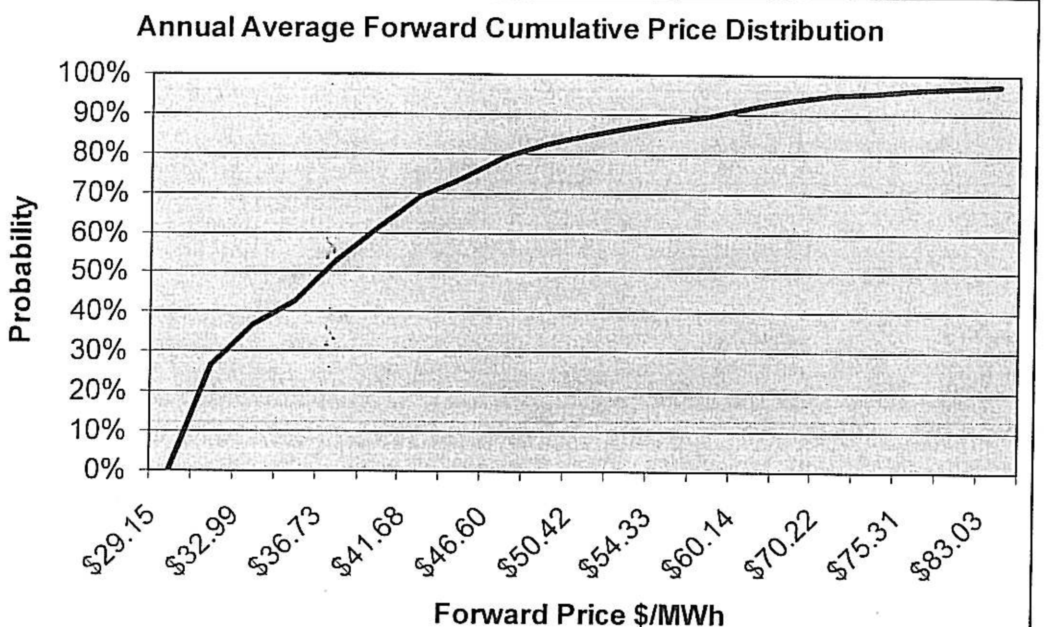
Due to these upward price pressures, there is a likelihood that future market prices will tend towards the high end of the range of possibilities shown in Figure 6-2. Using 43 cents per kWh, which is the mid-point of the high-end prices (at the 75th percentile), seems to be a reasonable estimate to use for valuing future energy prices in the spreadsheet cost-effectiveness model. It is likely that future costs will be in this range.

Valuation over the full range of prices and loads is preferable for obtaining an accurate assessment of the value of the demand response program in the face of uncertain forward markets. Note that there is approximately a 5% chance that the average price will exceed 69 cents per kWh, and even though this probability is low, its consequence or price times load impact is high, which must be accounted for in an overall assessment of demand response program risk and value.

DSMore additionally reports the cumulative probability distribution of the annual average around-the-clock (ATC) energy price. This distribution is useful for comparing the annual average price expectations with traditional market price publications, utility production cost model results, or internal forward price projections. Although our programs are targeting the top 28 hours, the price volatility and absolute level of the top prices are often correlated with forward market expectations. The ATC cumulative price distribution is shown below in Figure 6-2.

[31] Associated Press recently reported the results of a new computer analysis by the Goddard Institute for Space Studies in New York suggesting that peak summer temperatures in the Southeast could reach 110 degrees if climate change continues at its current pace. The computer analysis also shows the high temperatures could reach as far north as Washington and Chicago. The latest study is one of the first to look at potential weather extremes on a regional basis.

Figure 6-2. PJM New Jersey Market Around-The-Clock Energy Prices



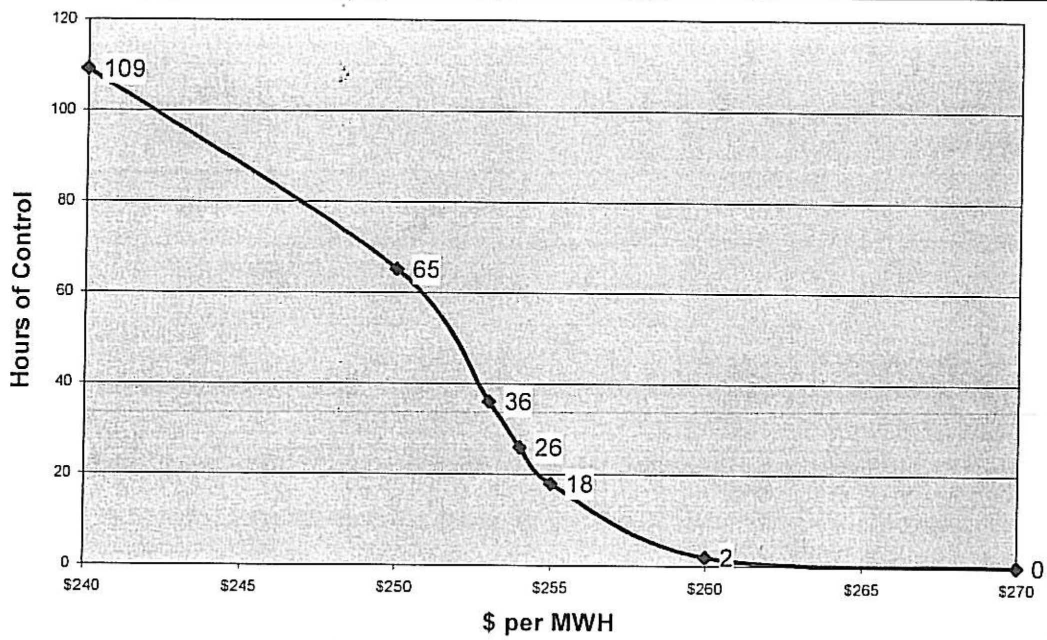
6.4.2 Impact of Energy Values on Criteria for Calling Control Events

The basic control strategy assumption used in both the spreadsheet model and the DSMore model is that air-conditioners will be controlled at 50% cycling for the top 28 high price hours each year. This level of control is consistent with what is often actually done by other utilities who have maintained their participation rates.

Currently, control events are called in New Jersey when the day-ahead price is greater than $250 per MWH and a weather criteria is met. But is $250 per MWH the right criteria to get an average of 28 hours of control each year? This question can be addressed by DSMore.

Based on the DSMore market price forecasts for New Jersey, Figure 6-3 shows the average number of hours that are expected to occur at or above the given market price criteria. Looking at all of the different possible weather/market price scenarios, it is predicted that there will be an average of 109 hours averaged over each year that will be at or above $240 per MWH. A criterion of $240 would create too many control hours. Likewise, a criteria of $260 per MWH would only create an average of 2 control hours per year. This would not be enough. It would seem that $250 per MWH may be "just right", but it turns out that the average number of hours is sensitive to the price criteria between $250 and $255 per hour. While $250 indicates an average of 65 control hours per year, a small increase to $255 for the criteria drops the number of expected control hours down to 18. A criterion of $254 per MWH gives 26 control hours, a close match to the desired 28 hours.

Figure 6-3. Average Hours of Control for Different Market Price Criteria



Source: Summit Blue analysis using DSMore model for New Jersey, May 2007

The difference between $250 and $255 is very slight compared to the difference between 65 hours and 18 hours. This indicates both that the current $250 criteria is the right breakpoint price for indicating extreme price events, but also that watchfulness and judgment should be used in actually calling control events based on this criteria due to the instability in the number of control hours near this threshold.

It is important to note here that these forecasted market prices are based on historical weather, load and price distributions. As discussed earlier, there are external factors, such as increasing fuel costs, transmission congestion, global warming and potential supply shortages that may put additional upward pressure on market prices above what is captured in the historical relationships. Because of these upward pressures we should assign at least some weight to the higher price scenarios and expect that future price criteria may need to be higher than what is shown here to maintain an average of 28 control hours per year.

6.4.3 Estimating Cost of Transmission Congestion

Transmission congestion is a problem for the PJM New Jersey region. During peak times there is a limit on how much power can be brought into the New Jersey region from the PJM West region because of a lack of transmission capacity. This transmission congestion increases prices in the New Jersey region during peak times.

DSMore used the PJM New Jersey region prices to develop the C-E tests for this study. This means that the effect of transmission congestion in the area has been included in this assessment of the cost-effectiveness of AC DLC programs in New Jersey, given that the observed market prices are presumably inclusive of congestion costs.

For comparison purposes, DSMore was also modeled on PJM West prices. The average PJM West price for the top 28 price hours was estimated at 21 cents per kWh, compared to 36 cents for PJM New Jersey. Similarly, the PJM West price at the 75th percentile was 29 cents compared to 43 cents for PJM New Jersey. This shows that avoided energy costs would be different in the PJM West area than in the PJM New Jersey area, and part of the reason for this difference is transmission congestion.

6.5 Comparison of Spreadsheet and DSMore Cost-Effectiveness Analyses

This section compares the results of the two cost-effectiveness methods. The results of the TRC benefit-cost assessments for the two methods are shown in Table 6-3 below. In general, the DSMore approach produces greater benefit-cost ratios, due to the fact that the DSMore model is able to include the higher benefits of additional load impacts at higher prices during extreme weather events. However, in terms of discriminating between the scenarios, the scenarios were still found to be ranked the same based on the benefit-cost results in both approaches. The fact that both methods produced results that were somewhat similar provides a greater overall level of confidence in the results.

Table 6-3. Comparison to DSMore – TRC Test

Scenario	MW Impact	Total Resource Cost Benefit/Cost Ratio *(with incentives as transfer payments)*	
		Spreadsheet Model	DSMore Model
(A) Switch with **no change** to automated return communication in the future through AMI	303	1.6 to 2.2	1.5 to 2.2
(B) Switch with automated return communication through the meter when **AMI** is in place	349	2.3 to 3.3	2.5 to 3.7
(C) Thermostat with **no change** to automated return communication in the future through AMI	303	2.0 to 2.9	1.8 to 2.7
(D) Thermostat with automated return communication through the meter when **AMI** is in place	322	4.3 to 6.3	3.6 to 5.3
(E) Thermostat with current automated return communication capability	322	2.9 to 4.2	2.8 to 4.1

Note 1: The ranges show the difference in test results when avoided capacity is valued at $65 per kW per year and $100 per kW per year.
Note 2: Scenarios B and D do not include costs for the AMI system itself.
Source: Analysis by Summit Blue Consulting, May 2007

The results for the RIM benefit-cost analysis are examined in Table 6-4 below.

Table 6-4. Comparison to DSMore - RIM Test

Scenario	MW Impact	Rate Impact Benefit/Cost Ratio	
		Spreadsheet Model	DSMore Model
(A) **Switch** with **no change** to automated return communication in the future through AMI	303	1.2 to 1.6	1.1 to 1.7
(B) **Switch** with automated return communication through the meter when **AMI** is in place	349	1.5 to 2.2	1.7 to 2.4
(C) **Thermostat** with **no change** to automated return communication in the future through AMI	303	1.1 to 1.7	1.2 to 1.7
(D) **Thermostat** with automated return communication through the meter when **AMI** is in place	322	1.6 to 2.4	1.7 to 2.5
(E) Thermostat with current automated return communication capability	322	1.2 to 1.8	1.3 to 2.0

Note 1: The ranges show the difference in test results when avoided capacity is valued at $65 per kW per year and $100 per kW per year.
Note 2: Scenarios B and D do not include costs for the AMI system itself.
Source: Analysis by Summit Blue Consulting, May 2007

7. PROGRAM AND TECHNOLOGY RECOMMENDATIONS

This section presents the recommended approach to pursuing residential and small commercial direct load control of central air conditioners in New Jersey. We have organized our recommendation into several higher level topics and within each topic present the program or equipment features we believe are key to the program and those that we believe are useful, but not absolutely required. These useful features may come in a bundled package offered by a technology vendor or might be value added features that improve the program that, based on the vendor's experience, can make a positive contribution to the program. As a result, it is recommended that the EDCs issue RFPs to vendors of appropriate equipment, specifying the very important features as required and asking for their best suggested approach that may take into account the useful but not required features in a final offer and quotation.

Each section below contains a recommendation and a corresponding rationale for that recommendation. The rationale presented is at a summary level. The material in the preceding sections provides underlying support for each recommendation.

7.1 Equipment Recommendation

The program should offer customers a choice between switches and thermostats. The current radio system should be used for sending out control signals to both switches and thermostats. The EDCs should not initially require that the system have built-in automated return communication capability (defined near the beginning of the Technology Overview). The EDCs should require that the devices can eventually be retrofitted with automated return communication capability without replacing the entire device. In the RFPs ask vendors to present solutions for moving from the current communication capabilities to an automated return communication system.

7.2 Key Features

This section presents features of the equipment and technology that are believed to be key to the program. In response to an RFP, a vendor should have the opportunity to present an alternative specification if it can be demonstrated that the same objectives are met.

KEY FEATURES

- Both thermostats and switches must be controlled from the same head-end (utility-side) computer system and using the same communications medium.
- Both thermostats and switches should be capable of using intelligent cycling (defined near the beginning of the Technology Overview).
- Customer override should not be possible from at the device – instead, overrides should require calling a toll-free number or using Internet communications.
- Thermostats should be able to both cycle compressors and perform temperature offset and temperature ramping.
- The control system must support many cycling approaches, including, but not limited to:
  - The cycling percent can be implemented by multiple approaches. For example, 50% cycling could be 15 minutes on/15 minutes off, or 10/10, or 30/30. 33% cycling could be 10 minutes on/20 minutes off, or 15 minutes/30 minutes.

  - o The cycling percent should be able to be changed over the course of a single event. For example, 25% cycling the first hour, 50% the second hour, 75% the third hour, and 25% the fourth hour.
- The control system must support creating multiple groups of participants and implementing different cycling or temperature offset strategies across those groups during the same event. The system must support changing the makeup of the groups from the head-end system (in other words, the groups are not hard-wired into the on-site equipment).
- The equipment should be able to be converted to automated return communication through the meter if an AMI system is installed by just replacing or adding components rather than replacing the entire thermostat or switch.
- The utility should have rights to the communications protocol and to head-end software and controls platforms so they can use it with equipment from other vendors in the future.
- The thermostats and switches must be able to randomize their starting and ending times (or provide a similar staged approach) within an event to avoid shocks to the system. For example, when all thermostats are given the same start signal, they each use a random number that determines when they will start control over the next 15 minutes.
- The thermostats and switches can start instantly upon receipt of signal, without using the random start feature, if so instructed. They will then use a randomization routine to determine the length of the first control period to avoid having all systems re-start at the same time.
- After a power outage, the thermostat or switch delays allowing the compressor to restart and uses a randomizing function to determine the length of that delay.
- The thermostat will display symbols and/or words to indicate that load control is underway.
- Device can be activated and de-activated remotely (without an on-site visit).
- Thermostats and switches should collect the data shown in Table 5-6.
- Thermostats should have sufficient memory to hold a minimum of 3 months of data.
- Thermostats should be able to receive an electronic signal to stop adding new data so a specific period of data can be maintained in memory long enough for it to be collected.
- The thermostat can be programmed with temperature settings based on price tiers to support a time-differentiated pricing tariff as an underlying part of the program.
- Thermostats are compatible with 2-stage compressors (vendors should specify whether one thermostat can control both 1- and 2-stage compressors or whether they would produce a separate thermostat for 2-stage compressors).

7.2.1 Useful but Not Required Features

This section discusses features that may come in bundled technology packages and would enhance the program. Decisions regarding these features will need to be based on price and value in the final offer and quotation. It is likely that some technology bundles can offer these features at little, if any, incremental cost.

- Thermostats and control system offer pre-cooling capability which can be a nice feature to increase customer comfort.
- Thermostats and switches are programmed to automatically turn off control (return to full user control) after a certain number of hours if they are put in a control mode without being set for or receiving end of control period instructions.
- Ability to download thermostat data while on-site but without the need for getting inside the house (e.g., remote reads data using ZigBee from outside the house).

- Ability to currently support automated return communication without using the meter as a conduit (i.e., using a gateway device of some sort to provide communication). (See the discussion of the vendor RFP requirements below.)
- The thermostat displays symbols and/or words on its face that:
  - Display pre-programmed message from the utility
  - Display custom, changing message from utility
  - Show that an event occurred on that day for participants that return to a hot home in the evening.
  - Show current electricity price information, such as price tiers (to support a TOU rate, with or without CPP) and/or actual prices (to support a real-time-pricing tariff).
  - Display words appropriate for a commercial space when used in commercial buildings (e.g., "occupied" and "unoccupied" instead of "wake" and "sleep")
- The thermostat display can be read in low light (e.g., by backlighting).
- The vendor provides a web interface for programming of the thermostat. (The RFP should ask vendors to discuss options for whether that web interface is hosted at the utility or the vendor's computers. The RFP should also ask whether the web interface has already been built and tested or whether it would be built under the contract.)
- Utility has access to all of the data stored in the switch or thermostat, including specifications on how the data is stored.
- Equipment compatibility
  - Thermostats can control more than one compressor (e.g., zoned system with more than one compressor controlled by a single thermostat).
  - Thermostats are compatible with heat pumps.
  - Thermostats are compatible with modulating, high-efficiency furnaces.

These "useful" features could comprise a check list in an RFP of value-added elements. These "useful" features are not viewed as unimportant, but are not viewed as "key" to the success of the program.

7.2.2 Other Equipment Elements

This section describes other equipment-related information that should be obtained. In addition to the features described above, the RFP issued by the EDCs should ask vendors to describe or address several other equipment related issues:

- Vendors should provide evidence to support how user-friendly the user interface is on their proposed thermostat.
- Vendors should define the temperature swing allowed by the thermostat and support the appropriateness of that value. Temperature swing is the range of temperature between when the thermostat turns off and on. Too large a swing can cause participant discomfort, too small a swing can reduce equipment life.
- Vendors should provide the size and shape of the thermostat and discuss how well it will cover the footprint of thermostats it is likely replacing.[32]
- Vendors should define periodic maintenance required by participants (e.g., battery replacement).

[32] If the new thermostat does not cover the footprint of the old thermostat, it may expose mounting holes and un-painted wall surfaces, with implications for installation costs and/or customer satisfaction.

- Vendors should define procedures (including equipment and software) for collecting data from the thermostats/switches while on-site (e.g., PDA connection via wires or infrared, ZigBee reader).
- Vendors should discuss whether their thermostat will continue to function if a participant drops out of the program or whether the thermostat will have to be removed because it does not function properly outside the program (e.g., without being in periodic contact with the head-end system).
- Vendors should define the potential for their thermostat or switch to communicate with AMI systems and other automated return communication approaches. Issues covered should include:
  - What kinds of communications systems are compatible with their thermostat?
  - Describe experience in implementing the technology in the field.
  - What must be done (with cost estimates) to retrofit the proposed model to enable such communication.
  - How well does the system work with full-scale, large DLC programs? Does it have the speed and bandwidth to send data back from each device for every event?

7.2.3 Flexibility to Allow Technology Upgrades in the Future – Research into Communications Developments

Over the next few years the EDCs should track advances in communication systems that would allow communication between the switch or thermostat and an AMI system or use some other mechanism to return data from the thermostat or switch to the utility. When available, a rollout of these more advanced communication systems should be incorporated into the program. In the equipment specifications above, a key feature was that the addition of AMI or other in-home communication to the thermostat or switch should be able to be accomplished without replacing the entire device. When available, the rollout would encompass all new participants, change outs, and a scheduled change to existing equipment that might, for example, call for 25% of the units to be retrofitted each year.

The reason why this flexibility is important is that rapid advances are being made in communication systems. The project team did not find AMI or gateway communications systems that have been demonstrated at a large scale and over a period of time.[33] Making this a requirement would severely reduce the number of vendors and technology options in the initial RFP for possibly a short-term gain. The research into communications options is important in that new options with a considerable number of enhancements should be available within the next 2 to 5 years. These systems can support measurement and verification, help improve the efficiency of maintenance activities, and improve customer program options and overall service. Such a system does not necessarily have to support communication between the thermostat or switch and the meter. The equipment recommendations are designed to allow for future communications upgrades.

To examine the options for providing better data, over the next few years the EDCs should track advances in communication systems that would allow automating the return of data from the thermostat or switch to the utility. They should monitor progress in in-home communication (e.g., ZigBee, HomePlug, WiFi) and field experience with using those technologies for communication between thermostats and AMI systems. EDCs should also track developments in approaches that do not depend on meters for communication such as thermostats that communicate through broadband Internet (whether broadband

[33] Two-way commercial paging is one system that has been demonstrated, but this technology is not available in all areas of New Jersey according to comments received from some of the Stakeholders participating in this project. However, combinations of approaches that can use the same curtailment software could be considered.

over power line, DSL, cable, or some wireless approach such as WiFi). It will be important to examine the following features:

- Overall cost of the communication upgrade.
- Can the communication medium handle the volume of data that would be produced by a large, full-scale AC load control program? Can it distribute the control signal in a timely fashion? Can it gather and process return data from all participants in a reasonable period of time (less than a day, potentially much less than a day)?
- How solid is the business that maintains the communication medium? How likely is it that it will maintain the system over the next 20 years? (This may be particularly relevant for 2-way paging systems if they become a component of the communications infrastructure in combination with other modes of communication to reach areas not covered by commercial paging systems.)

7.2.4 Equipment Recommendation Rationale

By offering customers a choice of both switches and thermostats, the EDCs can maximize participation. Through the vendor selection process, the EDCs can insist that both switches and thermostats can be controlled with the same cycling strategy and by the same control system to reduce complexity of operations and the cost of maintaining both approaches. Offering both technology should only modestly increase the administrative burden and requires maintaining inventory of both technologies. However, offering customers a choice preserves the existing customer base and experience. It also enables a rollout approach that gives the EDCs flexibility in how much time they take to install the new equipment. The legacy system can be maintained while the new equipment is offered and installed over time.

Offering thermostats gives the EDCs the potential to tie their AC load control program in with other programs, such as TOU and CPP rates, which could enhance the savings available from the programs operating alone.

Requiring vendors to be able to assign participants to groups will enable the EDCs to create groups to target congested transmission and distribution areas without necessarily controlling other areas of the state.

Programs that allow overriding control at the thermostat have experienced higher rates of overrides than those that require participants to call a phone number or visit a web page. The lower level of overrides improves the program's cost-effectiveness. In addition, if the participant has to over-ride by calling or using a web page, the utility can track the overrides and, if appropriate, devise strategies to reduce the level of overrides.

The C-E analysis indicates that the TRC is typically lowest for switch and thermostat scenarios that do not include some kind of automated return communication. The TRC that includes incentive payments is also low for thermostats that use public paging systems for automated return communication. Thus to be cost effective over the long term, some kind of automated return communication is necessary, whether through AMI or through some other mechanism that is less expensive than two-way paging. Load control without automated return communication is the most cost effective approach in the near term with current, proven technology and without AMI in place.

As discussed above, as the EDCs consider AMI deployment, they should continue to monitor the development of alternative communications mechanisms so that they can decide over the next few years whether they should implement a free-standing communications system or depend on AMI for a verification system for their DLC programs.

If AMI is installed, using it for automated return communication with the thermostat may still not be cost-effective. AMI would, however, make it possible to significantly reduce the costs of locating failed devices. AMI without communication with the thermostat or switch could still test whether devices are responding to control signals. This would greatly reduce maintenance costs by allowing targeting of on-site work to those sites most likely to really need attention. Given that the EDCs already own the outbound communication system, there is no great incentive to use AMI for control signal propagation. That leaves M&V support as the primary value of communication between the thermostat/switch and the meter with an AMI system. The marginal value of communicating thermostat data through AMI versus using meter readings alone via AMI to support M&V is not sufficient to justify **planning** to use a relatively unproven technology (thermostat-to-meter communication). As AMI-to-thermostat communication technologies mature over the next few years, it may prove to be an effective means for sending data back from the control devices.

Finally, one of the useful requirements was that thermostats be able to receive price signals and respond to these signals in a pre-programmed fashion. One of the new trends, but still being tested in the industry, is to offer DLC programs in combination with an underlying time-differentiated rate. This rate would allow the customer to use the programmable thermostat to save money every day which could add participants to the program since these potential bill savings would off-set the potential perceived inconvenience associated with AC curtailments. A program approach that would incorporate an underlying rate plan was strongly considered as a "recommended" approach, but due to the lack of experience with this approach (only limited pilots have been conducted) and the time to develop appropriate rates the consideration of this program design element was deferred to a future date. It should be possible to implement an underlying time-differentiated rate in several years, if this is still viewed as a desirable feature.

7.3 Control Strategy

This section presents the recommendations regarding the control strategies that should be included in the program design.

7.3.1 Cycling and Ramping Strategy – Recommendation

The EDCs should test a variety of cycling and ramping strategies to determine the strategies that best serve their needs in a variety of scenarios. The equipment specified, and most all available equipment, does allow for a variety of cycling and temperature set-back strategies. As a result, the impact of these strategies should be tested for the New Jersey program as the program is being rolled out. These test strategies should measure total load response, the duration of load response, and participant reactions and satisfaction. They should study utility and PJM system load curves under a variety of scenarios and define the most effective strategies for meeting system needs while maintaining the viability of the program by attending to participant satisfaction. During testing, participants should be assigned to different groups and controlled with different strategies on the same day to facilitate comparing impacts of the various approaches. Doing so adds only modestly to the costs and administrative burden of the program.

Examples of load control strategies that could be tested include the following (this is intended to represent examples of potential tests and is not a list of all approaches that should be tested):

- To test the program's ability to provide immediate relief in an emergency: 100% cycling with no random start for the first hour (or some shorter period), 66% cycling for the second hour, and 33% cycling for the third hour. Randomize the length of the first control period (e.g., with a minimum of 60 minutes and a maximum of 75 minutes) to distribute compressor loads over time.

- To test the program's ability to address a predictable needle peak: 50% cycling the first hour, 75% cycling the second hour, 33% cycling the third hour.
- To test the program's ability to address a broad peak, lasting several hours:
  - Temperature ramp-up 2 degrees per hour, or
  - 33% cycling first hour, 50% the second, and third hour, 33% the fourth hour

7.3.2 Cycling and Ramping Strategy – Recommendation Rationale

The program may need to respond to a variety of circumstances over time. No one control strategy will provide the optimal results for all circumstances, and there may be multiple choices available for tackling any one specific circumstance. By testing multiple approaches, the New Jersey EDCs will learn which approaches work best in their territories and meet their specific needs. The advantages and disadvantages of the high-level approaches are as follows:

Temperature offset advantages:
- Produces equivalent reduction from all participants (fairer).
- Impact on customer comfort is predictable.

Temperature offset disadvantages
- It produces shorter-term load reductions than duty cycling.
- Some customers think it's intrusive.[34]
- In a heat storm, it may produce no savings – many ACs will be operating full time and still not reaching their setpoint.

Cycling advantages
- With intelligent cycling, produces equivalent reduction from all participants (fairer).
- Demand savings are more predictable.

Cycling Disadvantages
- Unknown effect on customer comfort.

7.4 Event Criteria

The recommendation made here is aggressive in the number of events that can be called and the number of hours per event. This is meant to allow the program to be available when additional reliability is needed on the system. It is not expected that the full number of events will be called nor the full event period be called, except during very rare circumstances. It is expected that seven to eight events will be called per season, with a four hour duration. This was the basis for the C-E modeling performed in the preceding sections.

7.4.1 Event Criteria – Recommendation

Given this, it is recommended that the EDCs should set a limit on number of events per summer to 20. They should set no maximum hours per day that can be under control. They should set no maximum number of days in a row control can be called.

[34] E-Source "Cycling Strategies for Air-Conditioning Load Control Programs". ER-05-5 March 2005.

As a general rule, the EDCs should call control events when the day-ahead market predicts greater than $250/MWh and weather conditions are right. This will probably result in an average of seven events per year for a total of 28 hours. The EDCs should adjust this criteria as needed to ensure that several events are called each summer.

7.4.2 Event Criteria – Recommendation Rationale

Having a significant number of potential events gives planners more leeway to meet needs. The more events called, the more cost effective the program should be as long as dropouts do not become an issue. Increasing the allowable number of events enables the program to test the limits of participants' willingness to continue participating.

As they market and implement the program, the EDCs should track reasons given for not participating and for dropping out. If the number of possible events appears to be a significant factor, then they should reconsider the issue.

Several utilities have encountered customer dissatisfaction when they started calling more actual control events after years of limited use of the program. SMUD conducted a conjoint analysis that revealed that customers are more concerned with the number of control events than the incentive levels, even though they will consciously state they are more concerned with the incentive levels.

7.5 Incentives

This section presents recommendations related to program incentives.

7.5.1 Program Incentives – Recommendation

For **switches**, the New Jersey EDCs should maintain their current incentives ($4 per month plus $1 per event for PSE&G and JCP&L, $1.50 per month plus $1.50 per event for ACE) to minimize disruption and confusion for current participants. For **thermostats**, the EDCs should provide and install the thermostat for free and provide a $50 signing bonus for new customers (including new occupants in a home with a load control program thermostat already installed). The EDCs should monitor their success in marketing the program and modify the signing bonus as needed to manage their sign-up rate.

Allow one customer override per year for thermostats with no penalty. Repeated overrides can result in a participant being dropped from the program. The override capabilities of the equipment are specified in the equipment recommendation made above.

All program designs are based on forecasts that need to be confirmed as the program is rolled out. It is recommended that the incentives (and the program marketing) be reviewed each year with changes considered if participation is lagging behind targets. There are many incentive approaches being used by utilities. While the project team believes this approach to be appropriate, it is important to conduct ongoing customer research to both assess incentives and program operations.

7.5.2 Program Incentives – Recommendation Rationale

The current New Jersey incentives for switches are a good balance between fixed and variable incentives. Table 7.1 compares incentive levels for many of the large, existing switch programs. Participants are already familiar with this level of incentive, so it minimizes disruption. A higher per-event incentive would make the variable cost of calling a control event too high. The result would be a situation like

Madison Gas & Electric has, where calling a control event is so expensive that it is the highest cost option on a real-time variable cost basis. The current split between per year and per event incentives is a good balance.

The selling point to the thermostat participants will be that they will get a free thermostat, ability to program it over the web, ability to override control events, and use of the thermostat to save energy (and money) year-round.

Table 7-1. Comparison of Incentives for Switch Programs

Fixed Incentives	
Toronto Hydro	No annual incentive; $25 sign-up bonus
United Illuminating – Connecticut	Annual $20 or Green Rate Certificate
Commonwealth Edison	Annual $20 ($5 for 4 months)
Indianapolis Power & Light	Annual $20 ($5 for 4 months)
Vectron Energy Delivery	Annual $20 ($5 for 4 months)
MidAmerican Energy Company	Annual $30 ($40 in first year)
Idaho Power	Annual $21 ($7 for 3 months)
Alliant – Wisconsin	Annual $32 ($8 for 4 months)
Wisconsin Public Service	Annual $32 ($8 for 4 months)
Connexus Energy	Annual $35 ($8.75 for 4 months)
Baltimore Gas and Electric	Annual $40 ($10 for 4 months)
Xcel	15% of monthly bills in summer
Varies by Cycling Level	
WE Energies	Annual $12 to $50 depending on cycling level chosen
Varies by Number of Events	
Atlantic City Electric	$1.50 per month plus $1.50 per event
Jersey Central Power and Light	$4.00 per month plus $1.00 per event
Public Service Electric and Gas	$4.00 per month plus $1.00 per event
Potomac Electric Power Company	Pegged to PJM market
Madison Gas and Electric	Sign-up bonus of 8 CFLs, installed programmable thermostat or $25 bill credit; $2 for every 15 minutes of load shed (rarely used; currently being revised)
Varies by Cycling Level and Number of Events	
Duke Energy – Indiana	Pegged to current power costs
Sacramento Municipal Utility District	Annual $10 plus $1 per event at 45% Annual $20 plus $1 per event at 67% Annual $30 plus $1 per event at 100%
Southern California Edison	Two levels of discount depending on number of control events allowed: Max. 15 events at 5/10/18 cents per ton-day for 50%/67%/100% off cycling; or Unlimited events at 10/20/36 cents per ton-day for 50%/67%/100% off cycling

Source: Summit Blue summary of secondary research (see Bibliography for sources)

7.6 Customer Eligibility

This section discusses eligibility for the program and associated recommendations.

7.6.1 Customer Eligibility – Recommendation

Participants must have a central AC system or electric heat pump. They must own and live in the home (Owner-Occupied). If a home has more than one AC unit and has elected to get a switch, each AC unit must receive a switch. Each unit receives an incentive.

If a home has more than one AC unit and has one thermostat that controls both compressors, they will be eligible for one thermostat and one incentive. If each thermostat controls its own compressor, they are eligible for one thermostat and one incentive per compressor. All thermostats must be controlled.

Small commercial customers whose AC equipment can be matched to the curtailment technology should be eligible for the program when processes and standards are ready. Each utility should define the size of commercial customer eligible to participate to match its own unique population and ensure the size of the customer is compatible with the equipment utilized for the overall program, i.e. allowing for a common program implementation strategy across both residential and small commercial groups.

7.6.2 Customer Eligibility – Recommendation Rationale

The owner-occupied criterion simplifies marketing and administration as there is no need to contact both landlords and tenants for a single job. It also should reduce customer churn and possible over-payment of the thermostat incentive.

Small commercial customers can provide significantly more demand savings than residential customers, which can improve the program's cost-effectiveness, and the myPower Link program found that small commercial participants can be happy with an AC DLC program. However, by limiting the size of the commercial customer, the AC systems will be compatible with the same thermostats and switches. This means that a common program implementation strategy can be applied across both groups.

7.7 Migration of Existing Participants

New Jersey currently has a large number of customers on an AC DLC switch program using older technologies. The maintenance costs to ensure that the switches in the field are working and providing the expected load reduction has increased, and program maintenance declined after re-structuring due to shift in EDC responsibilities to a focus on distribution. Still, there are a large number of current participants and the migration of these participants to the new program is an important issue.

7.7.1 Migration of Existing Participants – Recommendation

Existing participants should be offered the same equipment and incentives as new ones. They should be encouraged to choose a thermostat but allowed to continue with a switch. Those who choose to take a thermostat should receive the thermostat in the same general time frame as new participants. Those who choose to continue using a switch should have a new switch installed so the program can take advantage of its benefits. Those participants who do not respond to program requests should have a new switch installed.

In conjunction with the maintenance and M&V approach (discussed below), the EDCs should develop a schedule to go on-site to all existing participants who have elected to continue with the switch. Once on-site, all switches should be changed out to the new switches.[35] It is anticipated that all current participants would be enrolled in the new program within five years – this matches the roll-out schedule modeled in the cost-effectiveness analyses.

7.7.2 Migration of Existing Participants – Recommendation Rationale

Given the age of most existing switches and the cost of going on-site, it is more cost effective to replace the old switches with new ones than to perform a site visit and leave in place switches near the end of their design life. This also allows implementation of the features offered by the newer switches (intelligent cycling and, potentially, advanced communication).

Replacing failed switches only would be a viable strategy only if all three of these conditions hold: 1) an AMI system will be implemented in the near term; 2) advanced communication with switches is not anticipated (that is the AMI system will provide the only method of checking on the switch's operations); and 3) the communication protocol for the new switches is compatible with the old switches, so dual control and communication systems do not need to be maintained.

7.8 Maintenance and Monitoring & Verification

More utilities and reliability organizations are viewing demand response programs as resources. Just as a power plant needs maintenance, a DR program such as the AC DLC proposed here needs maintenance and measurement of the load delivered. This section presents the project team's recommendations in these areas.

7.8.1 Maintenance and M&V – Recommendation

Maintenance and monitoring and verification (M&V) activities cover two needs: 1) determining if the control devices are operating correctly and fixing them if they are not, and 2) estimating program impacts. They are covered together because some of their components overlap. Until some stand-alone automated return communication system or an AMI system is in place, the EDCs will have no way to accurately meet either of these two needs without doing a certain amount of on-site work. Thus the recommendations are divided between actions that should be done in the near term, in a pre-AMI or no automated return communication world, and those that should be done post-AMI or in an automated return communication world.

Pre-AMI (or automated return communication)

To determine if the control devices are operating correctly, the EDCs should go on-site at each participant's site to check for the existence and correct operation of the device. Each device should be visited once every five years.

Yearly independent impact assessments should be implemented using a sample of participants with run time meters or compressor run-time logger data. A single impact assessment should be implemented to cover all New Jersey air-conditioning direct load control programs.

[35] However, if the new switches chosen are the same as ones used in the recent past and the current switch is not old (say five years old or less), then there would be no need to replace the switch.

Post-AMI (or automated return communication)

With AMI but no mechanism for automated return communication, each utility should develop procedures to test each control device remotely. The system should send control signals to shut down the AC then use the meter data to look for evidence of a change in usage that corresponds to shutting off the AC. [36] Such a test should be run on each device at least once a year.

With some mechanism for automated return communication, data should be collected from each thermostat and switch after each event to support calculating impacts and verifying device status.

Both approaches will have to be tested for sensitivity and rules should then be established to govern when a participant site visit is needed to directly check the condition of the device.

7.8.2 Maintenance and M&V – Recommendation Rationale

As discussed in the cost-effectiveness section, if the expected lifetime of a device is 20 years, five percent will fail each year on average. After five years, 25% will have failed. Since they fail at different times during those five years, the average time each one was in a failed condition is 2.5 years. Under a five year inspection program, each device will spend 2.5 years out of its total lifetime of 20 years in a failed condition. This will reduce program impacts by 2.5 / 20, or 12.5% per year.[37] In a pre-AMI, pre-automated return communication world, doing an impact assessment each year can be incorporated in the enhanced maintenance procedures recommended and will provide reliable estimates of the progress in bringing the program into a more active state. Doing one impact assessment to cover all EDCs will reduce costs for the M&V effort.

In a post-AMI or automated return communication world, the costs of doing regular tests to identify failed devices will be relatively small compared to the improved reliability of the system and thus the amount of dependable load reduction it can offer.

7.9 Program Roll-Out and Implementation – Next Steps

The EDCs should visit or contact selected utilities with installations of candidate equipment vendors through the summer and fall of 2007 to assess how the technologies are working now, and to assess what steps the utility had to take internally to run the program. The internal organization required to implement these programs can be underestimated. There was a suggestion that the New Jersey EDCs should request a small number of test devices from the potential equipment vendors to run small-scale tests of the systems during the summer of 2007 in utility employee homes (and as appropriate on test equipment), rather than on regular utility customers. However, most of the technology proposed for this program has been tested in numerous pilots and programs. Instead of using resources to test technology, the project team believes that discussions with other utilities implementing programs will provide greater insights into needed program features, implementation mechanics that are needed by the utility, quality control procedures, and customer service procedures.

A timeline is proposed below that would allow the EDCs to identify, select, procure, and install load control equipment for a program that would be operational for the summer of 2008.

[36] The length of the shut off need only be long enough to ensure that its effects are visible in the meter data.

[37] Source: This method of evaluating the cost of failed switches is derived from work done by Frank M. Hyde for Sacramento Municipal Utility District.

Table 7-2. Load Control Program Implementation Draft Schedule

Date	Activity
July 2007	Select candidate control systems
June-Aug.2007	Collect information from other utilities implementing programs to ascertain the actions the utility needs to undertake for a successful program.
July-Aug. 2007	Design program
Aug-Sept 2007	Obtain BPU approval of program
Sept.-Oct. 2007	Release RFP for control equipment
Oct-Nov. 2007	Select vendor, negotiate contract
November 2007	Submit order for equipment
Nov-Dec. 2007	Design marketing campaign
January 2008	Start marketing campaign and recruitment
February 2008	Start installations prior to the Summer of 2008
May-June 2008	Implement tests of communication and control equipment
June 2008	Select impact sample and install logging equipment
July 2008	Begin active program
Sept.-Oct. 2008	Retrieve logging equipment and start processing data for impact analysis
End 2008	First year report and impact analysis

The timeline above is recommended; however, each utility may have some regulatory or technical issues that might require some deviation. As a result, this timeline does have some flexibility. For example, depending on the vendor, orders for equipment could be placed as late as January. However, the project team believes that recruitment of participants should begin no later than February and installations of equipment should begin no later than March.

Finally, any program design is based on projections. It will be important to have a customer research program in place to test how participants are responding to incentives and to make any mid-course corrections needed in program operations. It is expected that this customer research would involve:

- An initial short survey of customers when they have the equipment installed to determine what aspects of the marketing campaign were influential in their decision to participate and to obtain information about the efficiency of the enrollment process, including equipment installation and the information provided on the operation of the equipment.

- A sample of customers should be contacted within 2 to 4 days after a control event to see what actions they took (if any) and to assess any customer issues with the event.

- An end of season satisfaction survey to see if customers were satisfied with the program overall and with specific elements of the program, as well as seeing if they would recommend the program to others. This can help in marketing.

While this customer research may seem like an obvious step that would be taken by EDCs, it should be planned out in advance of program implementation. With appropriate customer service and on-going communications, the AC DLC program can evolve over time to best meet EDC, overall electric system, and customer needs.

APPENDIX A:

INPUTS FOR COST-EFFECTIVENESS ANALYSIS

Descriptions of Data Inputs and Assumptions for Scenario A

Input	Description	Purpose	A. Switch with one-way communication with no change to two-way in the future through AMI	Documentation for Switch Scenario A
Demand Reductions	Average Hourly MW Reduction during all control hours	To estimate benefits; Allows a production cost model to estimate avoided capacity costs	325	Calculated value
Cycling strategy	Level of temperature offset and/or cycling strategy used	To estimate Demand Reductions and meet identified system needs for control	50% cycling for 28 hours, Spread over 7 events (days), Between 1:00 and 7:00 p.m.	NJ calls control periods whenever the electric price is expected to exceed $250 per MWH. Based on 2006 cost data, with perfect information control would have been called for 28 hours over 7 days. Use this as modelled control hours. Review of actual control events for other utilities that regularly control shows maximums of 15 events per year. SMUD did max of 15 per year when it used it's program for economic reasons. They cited increased participant dissatisfaction at this level. SMUD conjoint analysis showed that number of cycling events is the most important factor in the decision to participate. Excel-MN averaged 6.6 actual events per year from 1996-2001 and maintains a high participation rate.
Base KW impact per device	Expected KW load reduction per device under the given control strategy at the average temperature for control events and there are no overrides and all devices are working	To estimate Demand Reductions	0.96	Same as 2, but annual impacts are reduced because of switches that fail before detection. A regular five-year inspection program is assumed for this scenario. The SMUD study along with SBC calcs indicates that at a 5% failure rate per year, average annual impacts would be reduced by 12.5%. In other words, regular availability is 87.5%. (1.1 * .875 = .96)
Reserve Margin Factor	PJM Required Reserve Margin	Extra capacity that must be available to cover load on the system in the case of unexpected high demand or generation problems. If the load is removed from the system, the need for this extra capacity is also removed.	15%	PJM standard
Percent overrides	Percent of total customer-event-hours where the participant overrides utility control	To estimate Demand Reductions	0	No overrides on switches are allowed

Exhibit D
Attachment 5

Exhibit D
Attachment 5

Input	Description	Purpose	A. Switch with one-way communication with no change to two-way in the future through AMI	Documentation for Switch Scenario A
Average devices per participant	Many participants have two AC units and need two devices. Assume each device provides equivalent load impact.		1.08	In 2003, JCPL had 73,406 customers with 81,806 devices. PSE&G had 125,175 customers with 133,327 devices.
Number of Participants	Number of customers participating in the program	To estimate Demand Reductions	272,580	Calculated value; round to 275,000 for C-E tests
Program Participation Rate	Percent of eligible customers who would participate in the program	To estimate Number of Participants	17%	The NJ utilities were able to get 14% of the eligible market to participate in their programs in the past. With strong attention to marketing and retention, 17% is achievable.
Customer Incentive	Incentive customer receives for participating in the program	To estimate Program Participation Rate	$23	Same as current programs in NJ; $4 per month for four months, plus $1 per event; Expected total: $23 per cust per year
Residential Customers in Coverage Area	Number of Residential Customers within the area covered by communication towers	To estimate Number of Participants	2,813,000	ACE 450,000 plus PSE&G 1,800,000 plus JCPL Central Region 563,000
Central Air-conditioning Saturation Rate	Percent of Residential customers with central air-conditioning	To estimate Number of Participants	57%	Weighted average based on 65% for JCPL, and 55% for PSEG and ACE
Eligible Customers	Number of customers that meet the eligibility criteria	To estimate Number of Participants	1,603,410	Calculated as Residential Customers in coverage area times central AC saturation rate
Energy Reductions	Total MWH Reduction during all control hours	To estimate benefits; Allows a production cost model to estimate avoided energy costs	7,735	Calculated value based on 28 hours of control
Energy Costs during Control Periods	Average real-time price for energy in cents per kwh during the Control Periods	To estimate reduced energy costs from control	43 cents	Average RTP hourly cost from PJM Web site for hours greater than $250/MWH during summer 2006 (PSEG, JCPL and AECO nodes)
Snapback Energy	Additional MWH sold during snapback hours (immediately after end of control periods)	To offset energy reduction benefits with additional energy costs after the event	3,868	Based on Consolidated Edison, KCPL and WPS studies of snapback, estimate it is 50% of the energy impact and lasts for four hours after each control event.

Input	Description	Purpose	A. Switch with one-way communication with no change to two-way in the future through AMI	Documentation for Switch Scenario A
Energy Costs during Snapback Periods	Average real-time price for energy in cents per kwh during snapback hours (immediately after end of control periods)	To estimate increased energy costs after the control period	16 cents	Average RTP hourly cost from PJM Web site for 4 hours following each of 7 modelled control events for summer 2006 (PSEG, JCPL, AECO nodes)
Average Residential Rate	Cents per KWH	Estimate lost revenues	JCPL $0.194798 PSEG $0.163033 ACE $0.174640	From rate tariffs assuming Basic General Service. Includes all kwh-related charges. Use marginal rate for additional kwh during a summer month since that is what they will be paying for AC use.
Purchase Cost of Device	Per unit cost to purchase the device(s) which every customer must have to participate. Assumes the utility pays for it.	Cost	$100	From Technology Characteristics
Labor Cost to Install Device	Per unit cost to have the device installed at the customer's home. Assumes the utility pays for it.	Cost	$130	From Technology Characteristics plus $30 permit fee for New Jersey
Annual Cost to Detect and Repair Non-working Devices	Average cost per device per year to find non-working devices and repair them.	Cost	$30/device/year	Xcel-Minnesota did an in-depth study of this. One-third of their switches failed after 13 years in the field. This can be due to weather, customer or contractor tampering or removal, or old age. It cost them $600 to find and recover one kw. (Average load impact at 50% cycling was 1 kw per switch.) This works out to $30 per switch per year on average. If switches cost $100 and have an average lifetime of 20 years, the annualized cost to replace them is $5 per year. That leaves $25 per device per year for detection costs.
Start-up Cost of Control System	First year cost of software and hardware needed to run the control system	Cost	$0	From Technology Characteristics, first-time cost of control system is $35,000. NJ already has a Comverge control system. Assume no additional cost to use for new program.
Annual Cost for Communication System	Annual cost to use, lease or maintain the communication system.	Cost	$35,280	The NJ utilities own and operate 36 towers. PSEG analysis estimates $4,900 per tower per year to build and maintain. Assign 20% of cost to DLC.

Exhibit D
Attachment 5

Input	Description	Purpose	A. Switch with one-way communication with no change to two-way in the future through AMI	Documentation for Switch Scenario A
Start-up Program Adminisration Costs	Annual wages with loadings for all program managers and support staff to create processes to get customers signed up, billing system updated, installers organized and scheduled, control system tested and system operating integrated into controls.	Cost	$1,800,000	Start-up costs will be double on-going administration costs because of the additional work of developing processes and systems for the new program.
Annual Program Administration Costs	Annual wages with loadings for administrative support to keep program running and maintain participation levels on a regular basis. Includes customer service, phone center, database activities, etc.	Cost	$900,000	JCPL currently spends $280,000 on fixed program administration costs. PSEG spends $181,000 on fixed admin costs. JCPL spends an additional $155,000 on field maintenance while PSEG spends $805,000. Much of the field maintenance cost will be covered by the annual inspection program, but not all. Round fixed costs to $300,000 per utility.
Customer Acquisition Costs (no device exists in home)	Average cost per new participant to develop, produce and deliver promotional information.	Cost	$70	Xcel-Minnesota reports $70 per customer. This is equivalent to a 2% response rate on direct mail that costs $1.40 per piece. A 2% response rate to direct mail is reported by several utilities.
Annual Customer Drop-out Rate	Annual percent of participants who will drop out of the program either because they move to a new home or they are dissatisfied.	Cost	2%	JCPL data shows 8% drop-out over 4 years. This is 2% per year.
Customer Acquisition Costs (device exists in home)	Annual cost per new participant to maintain a system that identifies new customers in a home with a device and solicit their participation.	Cost	$10	This will require mailing a letter to each new occupant after they are identified. Assume $10 per new occupant.
Annual Measurement & Verification Costs	Average annual cost to measure and verify program impacts	Cost	$50,000	RLW/LBNL report cites $250,000 study every five years using traditional methods. PJM requires an impact study every five years.

Assumptions for Scenarios B and C

Input	B. Switch with one-way communication now and two-way through the meter when AMI is in place	Documentation for Switch Scenario B	C. Thermostat with one-way communication with no change to two-way in the future through AMI	Documentation for Thermostat Scenario C
Demand Reductions	372	Calculated value	326	Calculated value
Cycling strategy	50% cycling for 28 hours, Spread over 7 events (days), Between 1:00 and 7:00 p.m.	Same as 1	50% cycling for 28 hours, Spread over 7 events (days). Between 1:00 and 7:00 p.m.	Most programs offering free thermostats for participation state that temperatures will only go up 2 to 3 degrees. Vendors say 2 to 3 degrees is unnoticeable to customers and will be accepted. NJ occasionally needs a six-hour window of control. In those cases, raising temps 3 degrees for six hours would create very little load reduction in the last few hours. KCP&L did direct comparison of 50% cycling to 4-degree temp offset ramp-up over 4 hours. Average load reductions from the temp offset were half of the 50% cycling. A 50% cycling strategy should be used to create a full, continuous load reduction. House temperatures would increase the same as with switches.
Base KW impact per device	1.1	A composite of past impact data for New Jersey was used to come up with an estimate of 1.1 kw. This assumes the switches will be maintained on a timely basis because of the AMI system.	1.034	Same as A, but annual impacts are reduced because of thermostats that get replaced with regular units when new AC is installed. A regular inspection program is assumed for this scenario. Because thermostats are not out in the elements and customers see and use them regularly, they will have a lower failure rate than switches. Assume half of the load de-rating used in A.
Reserve Margin Factor	15%	Same as 1	15%	Same as 1
Percent overrides	0	No overrides on switches are allowed.	7%	Override rates will be 20 to 30% unless they are limited in some way. Assume a tariff limit of one event per year. Not all customers would use them, and not all will occur immediately at the beginning of the control period, so percent overrides is half of 1/7, or 7%. Advance notification with an automated phone call will help customers prepare (pre-cool) and maintain comfort.
Average devices per participant	1.08	Same as 1	1.08	Assume each AC unit is controlled by its own thermostat.
Number of Participants	272,580	Calculated value	272,580	Calculated value

Input	B. Switch with one-way communication now and two-way through the meter when AMI is in place	Documentation for Switch Scenario B	C. Thermostat with one-way communication with no change to two-way in the future through AMI	Documentation for Thermostat Scenario C
Program Participation Rate	17%	Same as 1	17%	There is no conclusive evidence that the participation rate for a thermostat program would be different than the participation rate for a switch program.
Customer Incentive	$23	Same as 1	Free thermostat installed plus $50 signing bonus	Common offering from utilities with thermostat programs.
Residential Customers in Coverage Area	2,813,000	Same as 1	2,813,000	Same as 1
Central Air-conditioning Saturation Rate	57%	Weighted average based on 65% for JCPL, and 55% for PSEG and ACE	57%	Weighted average based on 65% for JCPL, and 55% for PSEG and ACE
Eligible Customers	1,603,410	Same as 1	1,603,410	Same as 1
Energy Reductions	8,863	Calculated value based on 28 hours of control	7,748	Calculated value based on 28 hours of control
Energy Costs during Control Periods	43 cents	Same as 1	43 cents	Same as 1
Snapback Energy	4,432	Calculated value	3,874	Calculated value
Energy Costs during Snapback Periods	16 cents	Same as 1	16 cents	Same as 1
Average Residential Rate	JCPL $0.194798 PSEG $0.163033 ACE $0.174640	Same as 1	JCPL $0.194798 PSEG $0.163033 ACE $0.174640	Same as 1
Purchase Cost of Device	$130	Add $30 for communications module in switch to communicate with AMI system	$200	Austin Energy and KCP&L both report $300 cost per device to cover hardware and installation; New York reports higher installation costs for electrical contractors (total cost=$550 per device); Assume NJ is more like KCP&L;

Input	B. Switch with one-way communication now and two-way through the meter when AMI is in place	Documentation for Switch Scenario B	C. Thermostat with one-way communication with no change to two-way in the future through AMI	Documentation for Thermostat Scenario C
				Verified in Technology Characteristics
Labor Cost to Install Device	$130	Same as 1	$100	see above
Annual Cost to Detect and Repair Non-working Devices	$7.50/device/year	Xcel-Minnesota did an in-depth study of this. After switching to use of an AMI system to find non-working switches, the cost to recover a kw dropped from $600 to $150 (75% reduction in cost).	$35/device/year	Detection costs are the same as one-way switches, $25 per device per year. In-home appointments increase expense, but greater reliability allows longer time between inspections. (Double the cost but half as often.) Annualized cost of replacement is $200 over 20 years, or $10 per device per year. Cost should not be lower than cost with an AMI system. Add $2.50 per device per year to cover cost of HVAC dealer program to keep them trained on continued maintenance of the thermostats.
Start-up Cost of Control System	$0	Same as 1	$0	Same as 1
Annual Cost for Communication System	$19,440	Same as 1	$19,440	Same as 1
Start-up Program Adminisration Costs	$1,800,000	Same as 1	$1,800,000	Same as 1
Annual Program Administration Costs	$900,000	Same as 1	$900,000	Same as 1
Customer Acquisition Costs (no device exists in home)	$70	Same as 1	$70	Same as 1
Annual Customer Drop-out Rate	2%	Same as 1	2%	Same as 1
Customer Acquisition Costs (device exists in home)	$10	Same as 1	$10	Same as 1
Annual Measurement & Verification Costs	$10,000	With AMI system, the impact evaluation quality would be improved and cost would be reduced (assume 80% reduction).	$50,000	Same as 1

Assumptions for Scenarios D and E

Input	D. Thermostat with one-way communication now and two-way through the meter when AMI is in place	Documentation for Thermostat Scenario D	E. Thermostat with current two-way communication capability	Documentation for Thermostat Scenario E
Demand Reductions	346	Calculated value	346	Calculated value
Cycling strategy	50% cycling for 28 hours, Spread over 7 events (days), Between 1:00 and 7:00 p.m.	Same as 4	50% cycling for 28 hours, Spread over 7 events (days), Between 1:00 and 7:00 p.m.	Same as 4
Base KW impact per device	1.1	Same as 4	1.1	Same as 4
Reserve Margin Factor	15%	Same as 1	15%	Same as 1
Percent overrides	7%	Same as 4	7%	Same as 4
Average devices per participant	1.08	Same as 1	1.08	Same as 1
Number of Participants	272,580	Calculated value	272,580	Calculated value
Program Participation Rate	17%	Same as 4	17%	Same as 4
Customer Incentive	Free thermostat installed plus $50 signing bonus	Same as 4	Free thermostat installed plus $50 signing bonus	Same as 4
Residential Customers in Coverage Area	2,813,000	Same as 1	2,813,000	Same as 1
Central Air-conditioning Saturation Rate	57%	Weighted average based on 65% for JCPL, and 55% for PSEG and ACE	57%	Weighted average based on 65% for JCPL, and 55% for PSEG and ACE
Eligible Customers	1,603,410	Same as 1	1,603,410	Same as 1
Energy Reductions	8,243	Calculated value based on 28 hours of control	8,243	Calculated value based on 28 hours of control
Energy Costs during Control Periods	43 cents	Same as 1	43 cents	Same as 1

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Input	D. Thermostat with one-way communication now and two-way through the meter when AMI is in place	Documentation for Thermostat Scenario D	E. Thermostat with current two-way communication capability	Documentation for Thermostat Scenario E
Snapback Energy	2,424	Calculated Value	2,424	Calculated Value
Energy Costs during Snapback Periods	16 cents	Same as 1	16 cents	Same as 1
Average Residential Rate	JCPL $0.194798 PSEG $0.163033 ACE $0.174640	Same as 1	JCPL $0.194798 PSEG $0.163033 ACE $0.174640	Same as 1
Purchase Cost of Device	$230	Same as 4, but add $30 for Zigbee communications module in thermostat (price quote from Zigbee module manufacturer, Riga Development, 4-6-07)	$225	From Technology Characteristics
Labor Cost to Install Device	$100	Same as 4	$200	From Technology Characteristics, installation requires 1 hour and 15 mintues (total) for two components: the thermostat and the input/output communication device, which is placed closer to the heating/cooling units. This is twice the time required for switch installation.
Annual Cost to Detect and Repair Non-working Devices	$12.50/device/year	Same as 4, but add cost of AMI detection ($2.50/device/year based on Excel numbers). Add this to replacement cost for thermostats ($10/device/year)	$10.63/device/year	A two-way thermostat would give verification of signal receipt. Return pages cost 9 cents each. If there were 7 events per summer, return paging cost would be $0.63 per device per year. Add this to annualized thermostat replacement cost of $10/device/year
Start-up Cost of Control System	$0	Same as 1	$0	From Technology Characteristics, first-time cost of control system is $35,000. NJ already has a Comverge control system. Assume no additional cost to use for one-way thermostat. Carrier two-way thermostat uses Carrier-hosted control system at no additional cost.
Annual Cost for Communication System	$19,440	Same as 1	$15/device/year	Technology Characteristics reports $1.20 per device per month for communication costs for two-way Carrier. Assume 12 months use. Utilities report annual cost of $15/device.

Input	D. Thermostat with one-way communication now and two-way through the meter when AMI is in place	Documentation for Thermostat Scenario D	E. Thermostat with current two-way communication capability	Documentation for Thermostat Scenario E
Start-up Program Adminisration Costs	$1,800,000	Same as 1	$1,800,000	Same as 1
Annual Program Administration Costs	$900,000	Same as 1	$900,000	Same as 1
Customer Acquisition Costs (no device exists in home)	$70	Same as 1	$70	Same as 1
Annual Customer Drop-out Rate	2%	Same as 1	2%	Same as 1
Customer Acquisition Costs (device exists in home)	$10	Same as 1	$10	Same as 1
Annual Measurement & Verification Costs	$10,000	Same as 2	$10,000	Same as 2

APPENDIX B:

COMMUNICATION TECHNOLOGY GUIDE

Communication systems are a large part of any Direct Load Control program. There are many communication systems available which could be used for sending or receiving signals. Each type has its own characteristics which define its capabilities, limitations and costs. This Communication Technology Guide provides some background information on the basic characteristics of communication systems that may be part of a Direct Load Control program.

Traditional Communication Systems

Direct load control systems have traditionally used radio frequency signals for sending out control messages from one central point to many receiving devices. Some newer systems are using high frequency paging. Paging is the use of a particular protocol (organization of information) on a radio frequency. Table B-1 identifies the different categories of radio frequencies and their general applications. The 900 MHz paging can also be used to return information to a central point.

Table B-1. Categories of Radio Frequencies

RADIO FREQUENCIES				
Category		Frequency	Wavelength	Applications
HF	High Frequency	3 MHz - 30 MHz	100m - 10m	Medium wave AM Radio = 530kHz - 1710kHz (MF)
VHF	Very High Frequency	30 MHz - 300 MHz	10m - 1m	TV Band I (Channels 2 - 6) = 54MHz - 88MHz (VHF)
				FM Radio Band II = 88MHz - 108MHz (VHF)
				Utility load control radio signals 154 MHz
				TV Band III (Channels 7 - 13) = 174MHz - 216MHz (VHF)
UHF	Ultra High Frequency	300 MHz - 1000 MHz	1m - 0.1m	TV Bands == IV == & V (Channels 14 - 69) = 470MHz - 806MHz (UHF)
				Paging 900 MHz

Alternative Communication Systems

There are also other communication methods that could be used for sending and/or receiving information within a Direct Load Control system. Some of these have been around for awhile. Florida Power and Light has been using a TWACS system to send and receive information since 1987. However, many of these are new and still being developed for application to a Direct Load Control system.

Local Area Network (LAN) systems send communications within a house or a building, or up to 200 feet outside the building. These systems are good for getting information exchanged between difference devices within close proximity to each other. Table B-2 gives examples of different LAN systems.

Table B-2. Examples of Local Area Networks

LOCAL AREA NETWORKS (LAN)		
Category	Type	Examples
Wired	Serial Cables	RS-485
	Standard Household Electrical Wiring (up to the transformer)	X10
		UPB
		CEBus
		HomePlug
Wireless	Star Network	In-home router 802.11
		WiFi Hot Spot
		AMR Drive-by System
	Mesh Network	Zigbee
		LONWORKS
		Zwave

Wide Area Network (WAN) systems send communications from one home or business to other homes or businesses. These systems are good for getting information exchanged across far distances. Table B-3 gives examples of different WAN systems.

Table B-3. Examples of Different WAN Systems

WIDE AREA NETWORKS (WAN)		
Category	Type	Examples
Wired	Telephone Lines	Dial-up or DSL Internet
	Cable	Cable Internet
	Power Line Carrier (PLC) – Narrow Band	TWACS
		Turtle

WIDE AREA NETWORKS (WAN)		
Category	Type	Examples
	Power Line Carrier (PLC) – Broad Band *Also called BPL* *(Broadband over Power Line)*	Current Technologies
		Amperion
		Ambient
		SatiusMain.net
		Power Comm Systems
		Corridor Systems
Wireless	Star Network	Wireless Broadband Internet
		Sensus
	Overlapping Star Network	Cell Phones
		Hexagram
	Mesh Network	CellNet
		Stat Signal
		Trilliant

Issues Related to Communication Systems

Each communication system has unique characteristics that define its capabilities, limitations and costs. The unique characteristics of each individual system will not be defined here, but general issues that affect capabilities, limitations and costs will be discussed.

Slow vs. Fast

The speed of a communication transmission is usually measured by the baud rate. The baud rate measures bits per second. Divide by 10 to get the characters per second. For example, a 300 baud rate would be 300 bits per second, or 30 characters per second.

Narrow band PLC communications are generally slow, having a baud rate under 5k. Broadband PLC communications are much faster with a baud rate greater than 256k.

Distance vs. Penetration

Lower frequency systems are generally better for outdoor and/or rural communication. They are able to cover complex terrain and get around large obstacles. Higher frequency systems are better for indoor and/or urban communication.

Private vs. Commercial Radio/Paging

A radio signal is sent out from antennas atop large towers. These towers can be privately owned and used exclusively by a single entity. The cost of the communication system is then a fixed cost. There are also towers owned by commercial providers that support many subscribers. Use of these towers usually has a cost associated with each message transmission.

Licensed vs. Unlicensed

The use of frequencies is regulated by the Federal Communications Commission (FCC). A license must be obtained from the FCC to send out a high wattage signal with a particular frequency in a particular area. For example, TV stations, Hexagram and the New Jersey EDCs private radio system all require licenses from the FCC.

The FCC designates some frequencies as available for a particular use. The 154 MHz frequency is designated for load control systems.

Low wattage signals can use frequencies without getting a license. These are generally limited coverage area applications. Examples are LAN wireless networks, marine radios, remote-control toys, personal walkie-talkies, CB radio, Bluetooth, and Zigbee.

Star vs. Mesh Network

In a star network, devices communicate with a single, central point. In an overlapping star network, a device can send data to one or more central devices at one time. An example is a cell phone network.

In a mesh network, devices use similar devices to move a message down the line, from one to the next. An example is Zigbee.

APPENDIX C: DETAIL ON NEW JERSEY RESIDENTIAL AIR-CONDITIONING LOAD CURVES DEVELOPED FOR THE DSMORE MODEL

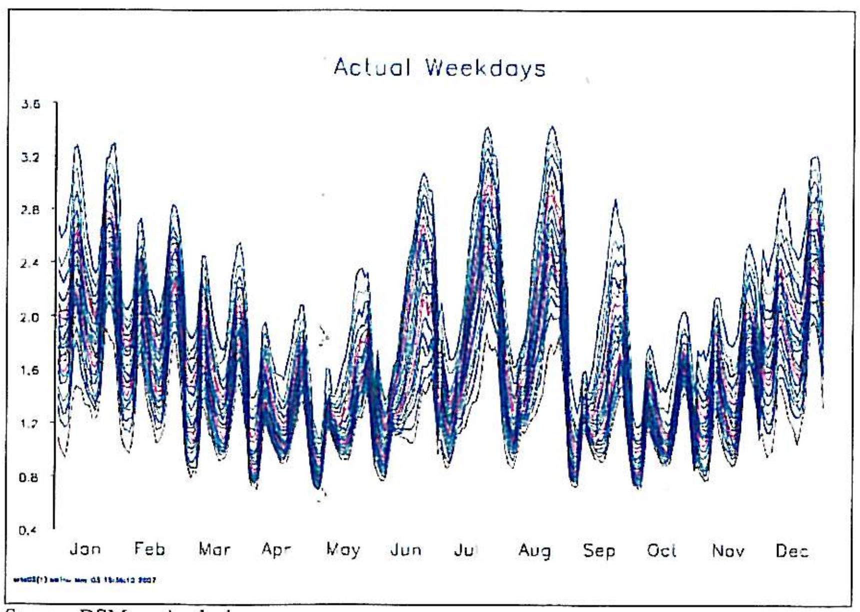
This appendix illustrates the load curves developed for the New Jersey market and used in the DSMore model. Air-conditioning response to weather was modeled using whole-house hourly load data for Ohio residential air-conditioning customers. They are in a comparable latitude weather band to New Jersey. Forecasts were estimated by specification of 576 non-linear regression models, covering variation in months, hours, weekend, and weekday daytypes.

The air-conditioning response models were then applied to New Jersey weather data to predict New Jersey residential air-conditioning customers' load response to future weather scenarios at the hourly level. In the following pages of this Appendix, you will see three general categories of graphical output, and each is explained below – actual load data, influence of extreme weather, i.e., "shocked" days, and covariance between high loads and high prices that can result in a high market prices.

Actual Loads

These graphs show the input load data as a set of percentile values. The lowest red line represents the minimum load value for that particular hour in a month, and the highest red line represents the maximum load value observed within the data for that hour in that month. Between the two red lines are a set of 19 deciles which reflect the 5th, 10th, etc. through 95th percentile values of all the input load data for that hour for the month. Given that peaks are expected to occur on weekdays, only weekday graphs are presented.

Figure C-1. Actual Weekdays

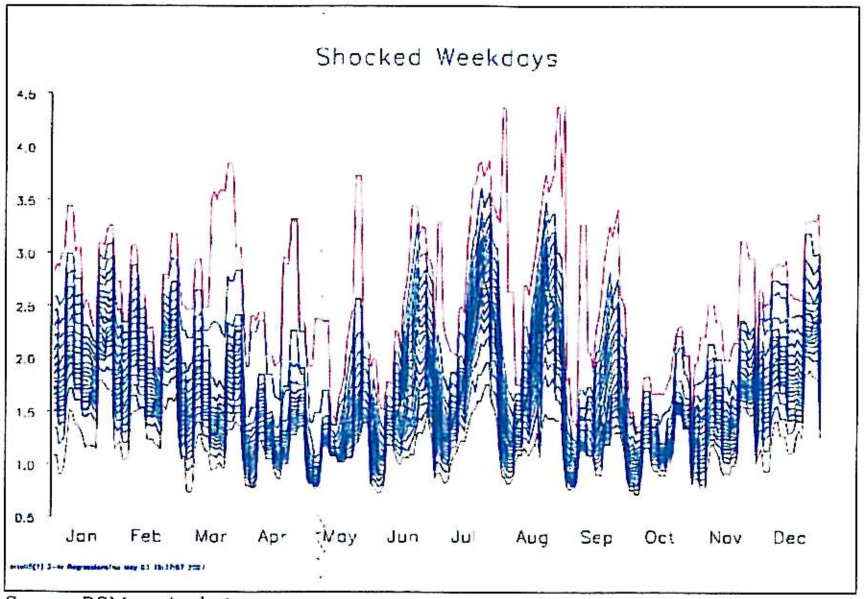


Source: DSMore Analysis

"Shocked" Load Forecasts

Using the models that were constructed earlier, and the standard errors for those models, a random shock within the bounds of the standard error calculation, is selected and applied to the predicted value to create a simulated or shocked load for each hour. The Shocked Weekdays graph percentiles these output values for, in this case, 33 years of 8760 data. Typically, the shocked or simulated values will have percentiles that are larger than what was observed in the actual data. This reflects the added risk that may exist in serving customer loads over the long run, where exposure to one or more extreme weather year scenarios exists.

Figure C-2. Shocked Weekdays

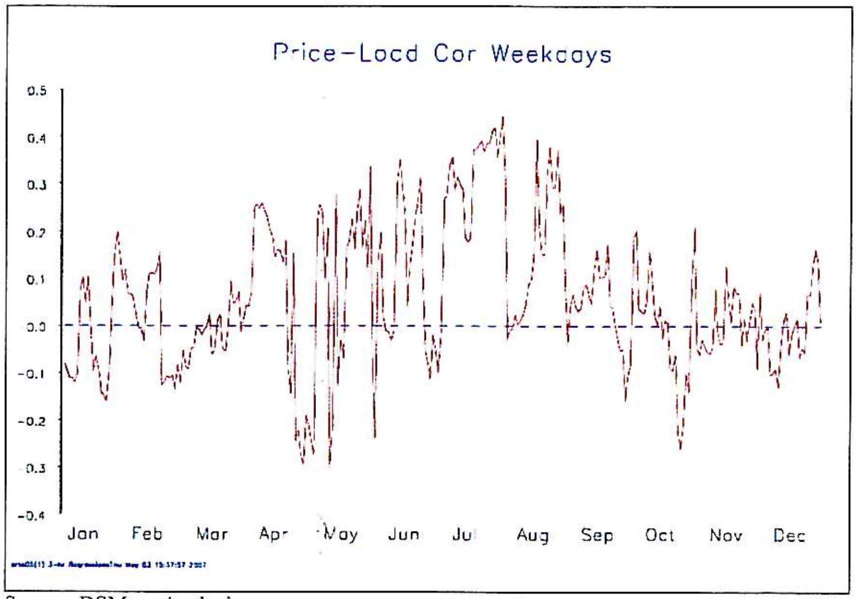


Source: DSMore Analysis

Price Load Correlations and Covariances

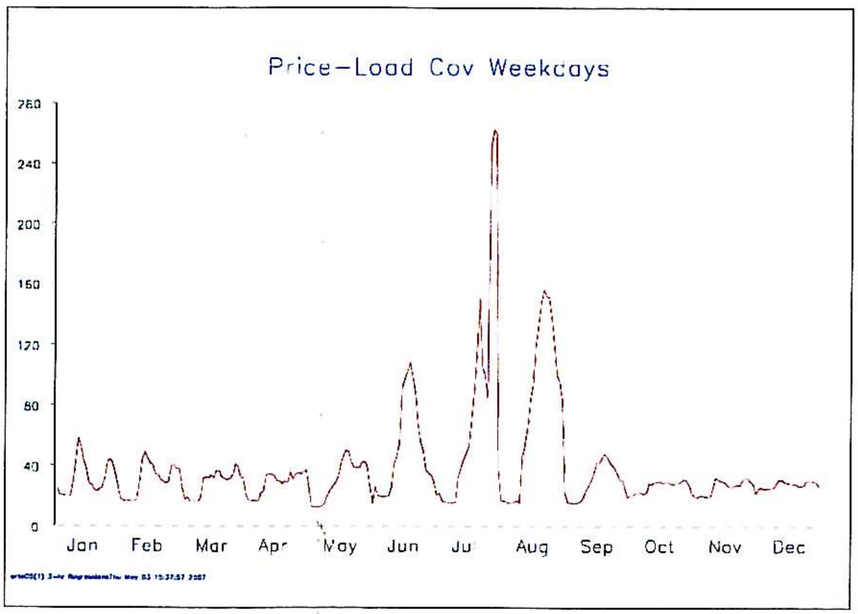
The correlation between the hourly prices and the hourly loads reflects the risk of serving that load during high priced times. Typically, the amount of covariance is higher in the summer or winter more so than during the shoulder months. Correlations are standardized between zero and one. Covariances are not. They are simply two ways of looking at the same thing. From the figures below, it is easy to see that higher correlations occur during the summer months. This is one of the factors taken into account within the DSMore price and load forecasts. It also shows that when price is high and load is also high, the totals expenditures by customers on electricity will also be very high (i.e., price x load), and any amelioration of this extreme day that can be achieved by a DR program such as an AC DLC program can provide benefits to the system.

Figure C-3. Price Load Correlations



Source: DSMore Analysis

Figure C-4. Price Load Covariances



Source: DSMore Analysis

APPENDIX D:

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PHI SERVICE COMPANY
STANDARD TERMS AND CONDITIONS FOR SERVICE CONTRACTS [WITH PHI CONTRACT SAFETY REQUIREMENTS – ATTACHMENT A V. 5 - 01172007]

1. **DEFINITIONS:** The following definitions shall apply to the Purchase Order (PO):
   a. Buyer: PHI Service Company, for itself, and/or as agent for any of its affiliate(s) either identified on the front of the Purchase Order, owned by or under common control with PHI Service Company, or receiving possession of the Services rendered (as defined below).
   b. Contractor: The person or entity to provide the Services (as defined below).
   c. PO or Agreement: The attached Purchase Order, issued by Buyer to Contractor, and these PHI Service Company Standard Terms and Conditions for Service Contracts, which are hereby incorporated by reference.
   d. Services: All labor and other Services to be provided by Contractor under the PO and Statement of Work (SOW), attached hereto and incorporated herein by reference.

2. **SCOPE OF SERVICES:**
   a. Contractor shall perform for the Buyer, in a good and workmanlike manner and subject to the provisions hereof, the Services set forth in detail in the SOW. Contractor will perform its duties in such manner as to avoid inconvenience to the Buyer's employees and interference with the Buyer's operations.
   b. Contractor's supervisory personnel shall inspect the premises and the work done by Contractor's employees and shall exercise complete control and authority over all such employees and the Services performed.

3. **CONTRACTOR'S EMPLOYEES AND EQUIPMENT:**
   a. To carry out the work covered by this PO, Contractor agrees to furnish, when and as required by Buyer, fully equipped, competent, experienced personnel. Contractor shall employ only persons who conduct themselves in a responsible, professional manner so as to not harm Buyer's reputation or adversely affect Buyer's relationship with its customers and/or the public. Buyer reserves the right, in its sole discretion, to determine who may perform work for Buyer. Upon written notice from Buyer, any person(s) who Buyer determines is not satisfactory shall be immediately replaced by Contractor with (a) satisfactory person(s).
   b. Contractor shall have a background investigation conducted on all its employees who will be assigned to perform work for Buyer, and shall require any subcontractors performing work for Buyer to similarly conduct a background investigation on all subcontractor employees who will be assigned to perform work for Buyer. Such background investigation shall, at a minimum, include a complete criminal history records check, conducted no more than one (1) year prior to assignment to PHI, which shall report all felony convictions within the previous seven years. Such background investigation shall be conducted by a competent professional organization and shall be in compliance with the Fair Credit Reporting Act and applicable state laws. Contractor agrees to provide Buyer with a complete copy of the result of such investigation for any employee who has been convicted of a felony as described above. Buyer reserves the right, in its sole discretion, to refuse to allow any individual with a past felony conviction to perform work for Buyer.
   c. Buyer requires that all employees of Contractor who work on Buyer work sites be free of drugs and the influence of alcohol. All such employees, when reporting for duty and while on duty, must be "fit for duty," defined as the appropriate mental and physical condition necessary to perform work in a safe, competent manner, free of the influence of drugs and alcohol. Possession of drugs, drug paraphernalia, and alcohol is prohibited on Buyer work sites.

4. **TERM AND TERMINATION:**
   a. **Term.** The term of this PO shall be as stated on the SOW.
   b. **Termination for Convenience.** Buyer may terminate this PO for its convenience, in whole or in part, by written or electronic notice at any time. If this PO is terminated for convenience, any claim of Contractor shall be settled on the basis of reasonable costs it has incurred in the performance of this PO.
   c. **Termination for Cause.** Buyer may terminate the whole or any part of Contractor's performance of work under this PO in any one of the following circumstances: (i) if Contractor fails to perform within the time

specified herein or any extension thereof; or (ii) if Contractor fails to perform any of the other provisions of this PO in accordance with its terms or so fails to make progress as to endanger performance of this PO. In the event of any such failure, Buyer will provide Contractor with written notice of the nature of the failure and Buyer's intention to terminate for default. In the event Contractor does not cure failure within ten (10) days of such notice, Buyer may terminate this PO by providing Contractor with a written "Notice of Default." In the event Buyer terminates this PO in whole or in part as provided in this clause, Buyer may procure, upon such terms and such manner as Buyer may deem appropriate, equipment or Services similar to those so terminated and Contractor shall be liable to Buyer for any excess costs for such similar equipment or Services; provided, however, that Contractor shall continue the performance of this PO to the extent not terminated under the provisions of this clause.

5. **PRICE AND PAYMENT:**
   a. **Prices.** The prices for Services are set forth in the SOW and shall remain fixed for the Pricing Period set forth herein. The Contractor represents that prices established in the SOW to be paid by Buyer shall not exceed the prices charged to any other customer of Contractor for Services which are the same or substantially similar to these Services, taking into account the quantities and terms of this PO. Moreover, Contractor agrees to refund any excess amounts paid by Buyer.
   b. **Invoices.** Contractor shall submit to Buyer an invoice, which includes the relevant P.O. number, for Services rendered, after completion of such Services. Payment for such Services will be contingent upon final inspection and acceptance by the Buyer's authorized representative and made payable on a net thirty (30) days after receipt and approval of Contractor's invoice for Services rendered. Should Buyer dispute an invoice or any portion thereof, Buyer shall pay all undisputed charges as required above, and at the time of dispute provide Contractor with written notice of such dispute.
   c. **Mechanics' Liens.** Contractor shall promptly pay for all materials, supplies, and labor employed by it so that the property shall be free from materialmen's and mechanics' liens. At time of invoicing, Contractor shall provide Buyer with lien releases from all subcontractors providing materials, supplies and labor related to the work.

6. **SAFETY:** Contractor shall comply with the attached, **"PHI CONTRACT SAFETY REQUIREMENTS – ATTACHMENT A V. 5 - 01172007"**, which is incorporated by reference herein.

7. **INDEMNITY:** The Contractor shall have the absolute and entire responsibility and liability for any and all injury, loss or damage of any kind or nature whatsoever, direct or indirect, suffered by any person or property (which terms for the purposes of this PO shall respectively include, without limitation, any employees or agents of Contractor or of any of its subcontractors, and any property of Contractor, or of any of its subcontractors, or its employees or agents) and arising out of, caused by, resulting from or suffered in connection with, the performance of the work provided for in the PO or any activity connected therewith. The term "activity connected therewith", for the purposes of this Article, shall include without limitation any operation, control or use by or for the Contractor or any of its subcontractors (or any employees or agents of either) of any equipment of the Buyer, whether such equipment was furnished by the Buyer with or without charge, and whether or not such equipment is being so operated, controlled or used was operated or controlled by any of the Buyer's employees.

   The Contractor hereby agrees to indemnify and hold harmless the Buyer and any and all of the Buyer's directors, officers, employees, agents and servants, and every other person directly or indirectly engaged on behalf of the Buyer in any activity connected with the performance of the PO or such work, from and against any and all demands, claims, liabilities, damages, losses, judgments, costs or expenses (including attorney's fees) incurred by the indemnitee in connection with injuries or damages to persons and/or property arising out of or resulting from any work performed hereunder (or any activity connected therewith), including without limitation such injuries or damages arising out of or resulting from negligence of indemnitee and excluding such injuries or damages only to the extent required by law. The Contractor agrees to defend, at his expense, any suit or action brought against the Buyer and/or any of the Buyer's employees based on any such alleged injuries or damages to persons and/or property arising out of or resulting from any work performed hereunder (or any activity connected therewith).

In the event that the Contractor fails to assume the Buyer's defense under the terms of this provision, it shall pay, in addition to the costs and expenses stipulated above, any and all costs to the Buyer, including attorneys' fees, in acting to enforce the Contractor's obligation hereunder.

8. **INSURANCE:** Before commencing the work, Contractor shall procure and maintain at its own expense the following minimum insurance in forms and with insurance companies acceptable to the Buyer:
   a. Workers' Compensation insurance for statutory obligations imposed by Workers Compensation, Occupational Disease, or other similar laws;
   b. Employer's Liability: $1,000,000 per occurrence;
   c. Business Automobile Liability (for all owned, non-owned, hired, and leased vehicles): $2,000,000 per occurrence;
   d. Comprehensive General Liability (including contractual liability insurance): $2,000,000 per occurrence, and an aggregate, if any, of at least $4,000,000. The contractual liability insurance coverage shall insure the performance of the contractual obligations assumed by Contractor under this Agreement, including specifically, but without limitation thereto, Section 7, entitled "INDEMNITY";
   e. Professional Liability (errors & omissions), where applicable, covering the professional Services being delivered by Contractor: $1,000,000 per occurrence. Such coverage shall remain in force for a minimum of three years following termination of Services under this PO;
   f. Upon acceptance of the PO, Contractor shall provide to Buyer's Corporate Insurance Department, located at 701 Ninth Street, NW, Washington, DC 20068, certificates of insurance acceptable to Buyer with respect to the above insurance requirements, and with respect to subsections c and d above, naming Buyer, its officers, directors, employees and agents as additional insured. Such certificates and insurance coverage required by this Section shall contain a provision that no coverage afforded under the policies will be canceled, materially changed or allowed to expire until at least thirty (30) days prior written notice has been given to Buyer. Such insurance shall provide a waiver of subrogation in favor of Buyer, state that coverage is primary to any other valid insurance available to Buyer (to the extent permitted by applicable insurance law), and allow cross liabilities and coverage regardless of fault;
   g. Contractor shall maintain adequate insurance coverage for subcontractors, and in the event any subcontractor(s) provide any Goods and/or Services for Contractor, Contractor shall require such subcontractor(s) to maintain insurance in accordance with the requirements of this Section.

9. **INDEPENDENT CONTRACTOR:** In all matters relating to this PO, Contractor shall be acting as an independent contractor. The employees of Contractor and its subcontractors are not employees of the Buyer under the meaning or application of any Federal or State unemployment insurance, social security, or worker's compensation law or regulation. Contractor shall assume and pay all liabilities and perform all obligations imposed by any such laws with respect to the performance of this PO. Contractor shall not have any right, power, or authority to create any obligation, express or implied, on behalf of the Buyer and shall not have any authority to represent itself as an agent of the Buyer.

10. **COMPLIANCE WITH LAWS:** Contractor shall comply with all applicable international, Federal, state and local laws, rules, and regulations including, without limitation and incorporated by reference herein, Section 202 of Executive Order 11246 (41 CFR Part 60), Section 503 of the Rehabilitation Act of 1973 (41 CFR Part 741), the Vietnam Era Veterans' Readjustment Assistance Act of 1974 (41 CFR Part 60-250), Public Law 95-507 (15 USC 637(d)), and all immigration laws pertaining to employment. Contractor, in accepting this PO, agrees that it shall certify, in writing, such compliance at Buyer's request.

11. **PUBLICITY:** Contractor agrees that it will not, without the prior written consent of Buyer, use in advertising, publicity or otherwise, the name or logo of PHI, or the name or logo of any affiliate of PHI, or refer to the existence of this PO in any press release, website, advertising or promotional material. Contractor shall, within five (5) days of the date of this Agreement, remove any existing reference to PHI or its affiliates from any website.

12. **GENERAL:**
   a. **Entire Agreement, Modifications, Non Waiver, and Severability.** This PO contains all the agreements and understandings between the parties with respect to the subject matter hereof. No agreement or other understanding in any way modifying the terms hereof will be binding unless made in writing as a

modification or amendment to this PO and executed by both parties. The failure of the Buyer to insist on strict performance shall not constitute a waiver of the provisions of this PO or a waiver of any other default by the Contractor. If any term or condition of this PO shall be deemed to be unlawful or unenforceable by a court of competent jurisdiction, such determination shall have no effect on the validity and enforceability of the other terms and conditions of this PO,

b. **Assignment/Subcontracting.** This PO may not be assigned by Contractor, and Contractor may not subcontract any portion of this PO, or any interest herein, or any payment due, or to become due hereunder, without the prior written consent of the Buyer.

c. **Non-Disclosure.** The Contractor hereby agrees that no data, documents or materials either supplied by the Buyer in connection with this PO or created by the Contractor shall be disclosed to a third party without the prior written consent of the Buyer. Contractor shall not identify nor use the Buyer's name or logo, or disclose the existence of this PO in any website, advertising or promotional materials without the prior written consent of the Buyer.

d. **Governing Law and Venue.** This PO is to be interpreted and enforced under the law of the jurisdiction where the Services are to be rendered (without regard to the choice of law provisions thereof), and any dispute involving the PO shall be heard in a court of competent jurisdiction in such jurisdiction. Where the Services are provided to or performed in more than one jurisdiction, this PO is to be interpreted and enforced under Delaware law.

e. **Force Majeure.** Neither party shall be considered to be in default in the performance of its obligations under this PO, to the extent that the performance of any such obligation is prevented or delayed by any cause which is beyond the reasonable control of and without the fault or negligence of the affected party. Contractor shall bear the risk of loss to all items damaged or destroyed by a Force Majure event.

f. **Notices.** Any notice provided hereunder shall be in writing via U.S. first class mail, certified mail, facsimile or hand delivery with confirmation of receipt to the addresses specified in the PHI Purchase Order, which may be changed by either party upon written notice.

CERTIFICATION OF SERVICE

PHILIP J. PASSANANTE, of full age, certifies as follows:

1. I am an attorney at law of the State of New Jersey and an Assistant General Counsel to Atlantic City Electric Company, the Petitioner in the within matter, with which I am familiar.

2. I hereby certify that, on August 1, 2008, I caused an original and eleven (11) copies of the within Verified Petition and exhibits thereto to be sent by courier service to Kristi Izzo, Secretary, Board of Public Utilities, Two Gateway Center, Newark, New Jersey 07102. I also caused an electronic copy to be sent to Secretary Izzo at kristi.izzo@bpu.state.nj.us.

3. I further certify that, on August 1, 2008, I caused a complete copy of the Verified Petition and exhibits thereto to be sent by First Class Mail to each of the parties listed in the attached Service List.

4. I further and finally certify that the foregoing statements made by me are true. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Dated: August 1, 2008

By: Passanante

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In the Matter of Atlantic City Electric Company's Responsive Petition
to the Board of Public Utilities Order Dated July 1, 2008 Regarding
the Submission of Demand Response Programs for the Period
Beginning June 1, 2009 for Electric Distribution Companies,
and for Supplemental Inclusion of Same in Its
"Blueprint for the Future" Filing Dated November, 19, 2007
Docket Nos. EO08050326 and EO07110881

Service List

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