Frances I. Sundheim
Vice President and Corporate Rate Counsel

Public Service Electric and Gas Company
80 Park Plaza - T8C, Newark, New Jersey 07102-4194
973-430-6928 fax: 973-648-0838
email: frances.sundheim@pseg.com

August 5, 2008

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of a Demand Response Program
and Associated Cost Recovery Mechanism
Pursuant to the BPU Order
I/M/O Demand Response Programs
for the Period Beginning June 1, 2009 –
Electric Distribution Company Programs

BPU Docket No. EO08050326

VIA ELECTRONIC, HAND-DELIVERY & REGULAR MAIL

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

Dear Secretary Izzo:

Pursuant to the Board's July 1, 2008 Order in the above-entitled matter, enclosed for filing are the original and ten copies of the Petition and supporting documents of Public Service Electric and Gas Company (PSE&G, the Company, Petitioner).

Copies of the Petition (electronic and hard) will be served upon those parties on the attached Service List.

Respectfully submitted,

Original Signed by
Frances I. Sundheim, Esq.

C Attached Service List

DEMAND RESPONSE PROGRAM
BPU DOCKET NO. EO08050326

BPU

Alice Bator, Bureau Chief
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
PHONE: (973) 648-2448
FAX: (973) 648-7420
alice.bator@bpu.state.nj.us

Victor Fortkiewicz, Executive Director
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
PHONE: (973) 648-4852
FAX: (973) 648-2409
victor.fortkiewicz@bpu.state.nj.us

Kristi Izzo, Secretary
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
PHONE: (973) 648-3426
FAX: (973) 638-2409
kristi.izzo@bpu.state.nj.us

Linda Nowicki
Board of Public Utilities
Division of Energy
Two Gateway Center
Newark, NJ 07102
PHONE: (609) 777-3314
FAX: (609) 777-3344
____

Suzanne Patnaude
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
PHONE: (973) 648-3858
FAX: (973) 648-2467
suzanne.patnaude@bpu.state.nj.us

Frank Perrotti
Board of Public Utilities
Division of Energy
Two Gateway Center
Newark, NJ 07102
PHONE: (973) 648-7290
FAX: (973) 648-2467
frank.perrotti@bpu.state.nj.us

Ronald Reisman
Board of Public Utilities
Office of the Ombudsperson
Two Gateway Center
Newark, NJ 07102
PHONE: (___) ___-____
FAX: (___) ___-____
Ronald.Reisman@BPU.state.nj.us

Samuel Wolfe, Chief Counsel
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
PHONE: (973) 648-2016
FAX: (___) ___-____
samuel.wolfe@bpu.state.nj.us

Nusha Wyner, Director
Board of Public Utilities
Division of Energy
Two Gateway Center
Newark, NJ 07102
PHONE: (973) 648-3621
FAX: (973) 648-2467
nusha.wyner@bpu.state.nj.us

DAG

Elise Goldblat, DAG
Division of Law
NJ Dept. of Law & Public Safety
124 Halsey Street
P.O. Box 45029
Newark, NJ 07102
PHONE: (973) 648-3441
FAX: (973) 648-7156
elise.goldblat@dol.lps.state.nj.us

Babette Tenzer
Division of Law
Department of Law & Public Safety
124 Halsey Street
PO Box 45029
Newark, NJ 07102
PHONE: (973) 648-7811
FAX: (973) 648-7156
babette.tenzer@dol.lps.state.nj.us

ADVOCATE

Stefanie A. Brand, Director
Department of The Public Advocate
Division of Rate Counsel
31 Clinton Street - 11th Floor
P.O. Box 46005
Newark, NJ 07101
PHONE: (973) 648-2690
FAX: (973) 624-1047
sbrand@rpa.state.nj.us

Ami Morita
Department of The Public Advocate
Division of Rate Counsel
31 Clinton Street - 11th Floor
P.O. Box 46005
Newark, NJ 07101
PHONE: (973) 648-2690
FAX: (973) 624-1047
amorita@rpa.state.nj.us

Diane Schulze
Division of the Rate Counsel
31 Clinton Street
11th Floor
P.O. Box 46005
Newark, NJ 07101
PHONE: (973) 648-2690
FAX: (973) 648-2193
dschulze@rpa.state.nj.us

ADVOCATE CONSULTANTS

Bruce Biewald
Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139
PHONE: (___) ___-____
FAX: (___) ___-____
bbiewald@synapse.energy.com

Robert Fagan
Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139
PHONE: (___) ___-____
FAX: (___) ___-____
rfagan@synapse-energy.com

Rick Hornby
Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139
PHONE: (___) ___-____
FAX: (___) ___-____
rhornby@synapse.energy.com

Jenn Kallay
Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139
PHONE: (___) ___-____
FAX: (___) ___-____
jkallay@synapse-energy.com

ATLANTIC CITY ELECTRIC CO.

Walt Davis
Atlantic City Electric Company
5100 Harding Highway
Mays Landing, NJ 08330
PHONE: (___) ___-____
FAX: (___) ___-____
walt.davis@pepcoholdings.com

Joseph Janocha, PE
PHI Rates and Technical Services
5100 Harding Highway
Atlantic Regional Office
Mays Landing, NJ 08330
PHONE: (609) 625-5868
FAX: (609) 625-5838
joseph.janocha@pepcoholdings.com

Philip J. Passanante, Assisant General Counsel
PHI Service Company
800 King Street, 5th Floor
PO Box 231
Wilmington, DE 19899-0231
PHONE: (302) 429-3105
FAX: (302) 429-3801
philip.passanante@pepcoholdings.com

Steve Sunderhauf
Pepco Holdings Inc.
701 Ninth Street, NW
Washington, DC 20068
PHONE: (202) 872-3507
FAX: (___) ___-____
slsunderhauf@pepco.com

JCP&L

Michael J. Filippone
Jersey Central Power & Light Co.
300 Madison Avenue
Morristown, NJ 07962
PHONE: (973) 401-8991
FAX: (973) 401-8224
mfilippone@firstenergycorp.com

Eva Gardow
JCP&L
300 Madison Avenue
P.O. Box 1911
Morristown, NJ 07962-1911
PHONE: (___) ___-____
FAX: (___) ___-____
egardow@firstenergycorp.com

Chris Siebens, Manager - Demand Response Programs
FirstEnergy Corp
2800 Pottsville Pike
Reading, PA 19605
PHONE: (610) 921-6694
FAX: (330) 374-7337
csiebens@firstenergycorp.com

ROCKLAND

John L. Carley, Esq.
Consolidated Edison Co. of NY
Law Dept., Room 1815-S
4 Irving Place
New York, NY 10003
PHONE: (212) 460-2097
FAX: (212) 677-5850
carleyj@coned.com

PSE&G

Gregory Eisenstark, Esq.
Assistant General Corporate Rate
PSEG Services Corporation
80 Park Plaza, T-05
Newark, NJ 07101
PHONE: (973) 430-6281
FAX: (973) 430-5983
gregory.eisenstark@pseg.com

Connie E. Lembo
Public Service Electric & Gas Co
80 Park Plaza, T-08C
Newark, NJ 07102
PHONE: (973) 430-6273
FAX: (973) 648-0838
constance.lembo@pseg.com

Frances I. Sundheim, Esq.
VP & Corporate Rate Counsel
Public Service Electric & Gas Co
80 Park Plaza, T-08C
Newark, NJ 07101
PHONE: (973) 430-6928
FAX: (973) 648-0838
frances.sundheim@pseg.com

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF A DEMAND RESPONSE PROGRAM AND ASSOCIATED COST RECOVERY MECHANISM PURSUANT TO THE BPU ORDER I/M/O DEMAND RESPONSE PROGRAMS FOR THE PERIOD BEGINNING JUNE 1, 2009 – ELECTRIC DISTRIBUTION COMPANY PROGRAMS,	))))))))))	**PETITION** BPU Docket No. EO08050326

Public Service Electric and Gas Company (Public Service, PSE&G, the Company, Petitioner), a corporation of the State of New Jersey, having its principal offices at 80 Park Plaza, Newark, New Jersey, respectfully petitions the New Jersey Board of Public Utilities (Board or BPU) pursuant to *In The Matter Of Demand Response Programs For The Period Beginning June 1, 2009 – Electric Distribution Company Programs*, Order dated July 1, 2008 (Demand Response Order) BPU Docket No. EO08050326 and *N.J.S.A.* 48:3-98.1(a)(3), as follows:

INTRODUCTION

1. Petitioner is a public utility engaged in the distribution of electricity and the provision of electric Basic Generation Service (BGS), and distribution of gas and the provision of Basic Gas Supply Service (BGSS), for residential, commercial and industrial purposes within the State of New Jersey. PSE&G provides service to approximately 2.1 million electric and 1.7 million gas customers in an area having a population in excess of 5.5

million persons and which extends from the Hudson River opposite New York City, southwest to the Delaware River at Trenton and south to Camden, New Jersey.

2. Petitioner is subject to regulation by the BPU for the purposes of setting its retail distribution rates and to assure safe, adequate and reliable electric distribution and natural gas distribution service pursuant to *N.J.S.A.* 48:2-21 *et seq*.

3. The BPU, in the Demand Response Order, adopted Board Staff's recommendations and directed, among other things, each of the State's electric distribution utilities to submit proposals for demand response programs that could be implemented by June 1, 2009, if approved by the Board. See Demand Response Order at p. 3.

4. The Board further ordered that the electric distribution utilities' proposals be geared toward achieving a statewide goal of 300 MWs of demand response above current levels for Energy Year (EY) 2009, and a total of 600 MWs of demand response above current levels by the end of EY 2011.[1] The Board stated that these goals are to be allocated among the four electric distribution companies based upon their respective share of statewide electric load. For PSE&G, the allocated share of electric load was determined to be 55 percent, thereby resulting in a target goal of 165 MW reduction for

[1] For the purposes of this Petition, PSE&G notes that Energy Year 2009 begins on June 1, 2009 and ends on May 31, 2010, while Energy Year 2011 starts on June 1, 2011 and ends on May 31, 2012. Accordingly, PSE&G has interpreted the Demand Response Order to mean that the Board has set the targeted MWs of incremental demand response to be achieved as of the end of each of Energy Years 2009 and 2011.

Public Service in EY 2009. *Id*. at pp. 2-3. The Board also stated that these energy reduction goals are open to comment and further review. *Id*.

5. The Board ordered that the utilities' proposals shall provide opportunities for all customer classes to participate in their respective demand response programs. *Id*.

6. The Board ordered that the proposals should consider incorporating outside energy contractors for program services including, but not limited to, installation services and operational support, and shall be based on a competitive process for the procurement of equipment and technology. *Id*.

7. Finally, the Board ordered that the proposals shall be specific in terms of projecting the cost-effectiveness of each demand response sub-program. *Id*.

8. As the Board was acting pursuant to the authority granted to it in *N.J.S.A.* 48:3-98.1(a)(3), pursuant to the BPU's 120 Day RGGI Order,[2] Board Staff convened a 30-Day Pre-Filing Meeting with all of the electric distribution utilities on July 1, 2008 at the Board's offices in Newark, New Jersey.

9. During the July 1, 2008 30-Day Pre-filing Meeting, BPU Staff asked each of the electric distribution utilities to describe, if possible, the nature of each of their contemplated demand response programs. In response, PSE&G stated that it did not have adequate time to develop specific details of any proposed demand response programs but

[2] Within 120 days after enactment of the RGGI legislation, the Board was required to issue an order that allows electric and/or gas public utilities to offer energy efficiency and conservation programs in their respective service territories on a regulated basis. On May 12, 2008, the Board issued such an Order pursuant to *N.J.S.A.*

stated it would make a good faith attempt to develop programs available to all rate classes to meet the August 1, 2008 filing date established by the Board. See Demand Response Order, Exhibit A.

10. During the July 1, 2008 30-Day Pre-Filing Meeting, BPU Staff indicated to the electric distribution utilities that while the Board was exercising its authority to direct the electric distribution utilities to make these filings under the BPU's 120-Day RGGI Order, it was the Staff's opinion that the minimum filing requirements set forth in the 120-Day RGGI Order would not apply to this instant proceeding. The rationale given by Staff was that the 120-Day RGGI Order was issued to address the 180-day BPU review and approval process mandated by the legislation for filings voluntarily proposed by the utilities. See *N.J.S.A.* 48:3-98.1. In this instance, in the Demand Response Order the Board set forth specific filing requirements and ordered the utilities' filings. Moreover, the Board has mandated that the review and approval process be conducted in less than 180 days, a timeframe not contemplated in RGGI. Therefore, Staff stated the minimum filing requirements of RGGI are not applicable to this filing.

11. Attached hereto, and incorporated herein by reference, is Appendix A, which identifies all of the applicable information Public Service believes, based upon the position of the Staff of the BPU's Energy Division that was communicated to the utilities at the July 1, 2008 30-Day Pre-filing Meeting, it is required to file in the instant

---

48:3-98.1(c). See BPU Order Pursuant to *N.J.S.A.* 48:3-98.1 (c) (120-Day RGGI Order), BPU Docket No.

proceeding. PSE&G requests that the Board support Staff's direction to the EDCs and waive those requirements from the 120-day RGGI Order that PSE&G has identified and delineated in Appendix A attached to this filing. These sub-programs reflect the Company's "best efforts" in developing programs and supporting data in an abbreviated timeframe.

12. PSE&G seeks Board approval to implement a demand response program to be made available to all customer classes in an attempt to achieve the electric load reduction goals set forth in the Board's Demand Response Order. Public Service proposes, through this regulated service, to target various customer classes in its Demand Response Program, specifically the residential segment; a small commercial segment and a large commercial/industrial segment. A description of each of these Demand Response sub-programs is provided in the pre-filed testimony of Frederick A. Lynk, which is filed herewith as Attachment A.

13. As discussed in the summary descriptions of each of the sub-programs, the equipment that PSE&G will use will be compatible with Advanced Metering Infrastructure (AMI) systems that PSE&G has proposed. Moreover, PSE&G is firmly committed to a fully-integrated "Smart Grid," including smart meters and appropriate communications hardware and software. New Jersey will only be able to achieve the aggressive demand reduction targets in the draft Energy Master Plan through a fully-

---

EO08030164.

implemented, AMI-enabled smart grid. AMI compatibility will help both regulated and market-based demand response initiatives, by helping customers respond to appropriate price signals and through more precise measurement of the customers' response to such market indicators.

PSE&G DEMAND RESPONSE PROGRAM SUMMARY DESCRIPTION

1. Residential Central Air Conditioner (AC) Cycling Sub-Program
Total Investment $57.5 million (from 2009-2013)
Targeted Demand Reduction 130.9 MW

- Targeted to residential customers in PSE&G's service territory.
- Replace existing equipment in a systematic manner over a five-year period.
- For each device that is found to be missing or inoperable and is replaced, PSE&G expects an incremental 0.72 kW will be available for demand response.
- This sub-program will also be made available to new participants. For each new participant enrolled, the incremental kW will be 0.72 kW. For new participants, either cycling switches or thermostats will be installed at the customer's option.
- PSE&G will specify the equipment that is compatible or that can be readily made compatible with Advanced Metering Infrastructure (AMI) systems that may ultimately be installed by PSE&G.
- All devices will be nominated into the appropriate PJM Demand Response (DR) markets and programs.
- PSE&G will use its own workforce to perform the installation work.
- PSE&G will use a competitive solicitation to procure the switches and thermostats.
- This sub-program is designed to achieve the following load impacts.

Year	2009	2010	2011	2012	2013	2014
DR Installed (MW)*	1.7	13.7	35.8	69.8	103.6	130.9

***** Installed as of March 1 each year. This amount is available to receive PJM DR benefits for the summer period in that year.

2. Residential Pool Pump Load Control Sub-Program
Total Investment $0.9 million (2009-2011)
Targeted Demand Reduction 2.4 MW

- Targeted to residential customers who have swimming pools.
- Above-ground pools will qualify as well as in-ground pools.
- Pool pumps will be retrofitted with switches that will curtail load when certain weather and wholesale prices are reached.
- Each installation will yield a peak reduction impact of 0.75 kW.
- This sub-program will be nominated in the appropriate PJM DR markets and programs.
- PSE&G will use its own workforce to perform the installation work.
- PSE&G will use a competitive solicitation to procure the load control devices.
- This sub-program is designed to achieve the following load impacts.

Year	2009	2010	2011	2012	2013	2014
DR Installed (MW)*	-	0.9	2.0	2.4	2.4	2.4

***** Installed as of March 1 each year. This amount is available to receive PJM DR benefits for the summer period in that year.

3. Small Commercial Customer AC Cycling Sub-Program
Total Investment $5.04 million (2009-2010)
Targeted Demand Reduction 19.1 MW

- Targeted to small commercial customers.
- For each new participant enrolled, the incremental kW impact is estimated to be 1.66 kW.
- PSE&G will specify the equipment that is compatible or that can be readily made compatible with AMI systems that may ultimately be installed by PSE&G.
- This sub-program will be nominated in the appropriate PJM DR markets and programs.
- PSE&G will use its own workforce to perform the installation work
- PSE&G will use a competitive solicitation to procure the load control devices.
- This sub-program is designed to achieve the following load impacts.

Year	2009	2010	2011	2012	2013	2014
DR Installed (MW)*	1.6	11.1	19.1	19.1	19.1	19.1

***** Installed as of March 1 each year. This amount is available to receive PJM DR benefits for the summer period in that year.

4. Commercial and Industrial (C&I) Curtailment Services Sub-Program
Total Investment $24 million (2009-2012)
Targeted Demand Reduction 240 MW

- Targeted to C&I customers.
- PSE&G will act as a Curtailment Service Provider (CSP) for participation in PJM's demand response initiative, targeting those C&I customers most able to undertake demand response.
- PSE&G will make an investment toward the installation of enabling infrastructure, similar to its proposed treatment of the hospital segment in the recently filed Carbon Abatement Program.
- This sub-program will be nominated in the appropriate PJM DR markets and programs.
- This sub-program is designed to achieve the following load impacts.

Year	2009	2010	2011	2012	2013	2014
DR Installed (MW)*	30	120	180	240	240	240

***** Installed as of March 1 each year. This amount is available to receive PJM DR benefits for the summer period in that year.

5. Load Shifting Demonstration Sub-Program
Total Investment $6 million (2009)
Targeted Demand Reduction 0 MW

- PSE&G will conduct several demonstration trials designed to effect load shifting. This sub-program will have four components: energy storage using a battery; plug-in hybrid electric vehicles (PHEVs); solar street lighting; and Coolness Storage.
- The Coolness Storage trial is the only component which directly involves customers. The Coolness Storage trial will be targeted to customers with large air conditioning loads that could install the necessary cool storage equipment that are also located in constrained distribution areas.
- PSE&G will evaluate and deploy these load shifting technologies as demonstration trials to determine the feasibility of their wide-scale adoption.

14. PSE&G has designed its Demand Response Program to target the MW reductions set forth in the Demand Response Order. In recognition that the development process for these new sub-programs began 30 days ago, and assuming a final Decision and Order on this matter in November, as well as the long lead times involved with

contracting for and the manufacture of equipment, PSE&G will not be able to meet the Board's target of 165 MW in the EY commencing June 1, 2009. The proposed sub-programs are expected to yield 30 MW in the EY commencing June 1, 2009. If the Board's Order in this matter is delayed for any reason, then the expected impact in year one will be in jeopardy. The 165 MW target is anticipated to be reached some time in the EY commencing June 1, 2010. The goal of 330 MW by year three is expected to be met by PSE&G by the EY commencing June 1, 2012. The ultimate anticipated demand reduction impact should be 392.4 MW, reached by the EY commencing June 1, 2013. PSE&G believes its plans to build Demand Response capability represents a realistic ramp-up rate that is consistent with the Board's objectives.

15. Public Service proposes that any disputes related to these sub-programs be resolved through the Board's established customer complaint process. PSE&G addresses the dispute resolution process in the testimony of Frederick A. Lynk, filed herewith as Attachment A.

COST RECOVERY PROPOSAL

16. PSE&G is requesting, for purposes of this Demand Response Program that the Board has directed the Company to file, that the Board grant approval of recovery of all Demand Response Program costs. PSE&G proposes to recover all Program costs via a separate component of the electric RGGI Recovery Charge (RRC) mechanism as proposed

[3] the Company requests that the carrying charge on its deferred balances for this Demand Response Program be set as PSE&G's overall weighted average cost of capital (WACC) authorized by the Board in the most recent base rate case, together with the income tax effects. In addition, PSE&G requests that it earn a return on its net investment in the Program based on its WACC. Finally, for the Demand Response Program , PSE&G proposes to share the payments it receives from PJM with customers via a credit to the RRC, subject to a cap of 100 basis points above the Company's overall established Return on Common Equity included in the WACC. The adjusted WACC of 12.1138% is shown on Schedule SS-2 to the pre-filed testimony of Stephen Swetz, filed herewith as Attachment B. PSE&G's proposed cost recovery mechanism for the Demand Response Program, including the estimated rate impacts on customers and proposed initial rates, is fully-described in the pre-filed testimony of Mr. Swetz. (Attachment B)

17. PSE&G also requests that all legacy Residential A/C Cycling program costs currently being recovered through the System Control Charge (SCC) now be recovered through the new demand response component of the electric RRC. Public Service believes that recovery of the legacy Residential A/C Cycling costs through the RRC is administratively more efficient. In addition, PSE&G proposes that the deferred balance

---

[3] *N.J.S.A.* 48:3-98.1 (b)

in the SCC be transferred to the demand response component of the electric RRC on the date that the new RRC rate becomes effective, at which time the SCC rate will be set to zero.

18. The cost-effectiveness of each sub-program, will be provided as Attachment C, no later than August 22, 2008. Due to the extremely compressed time period allowed for this filing under the Board's July 1 Demand Response Order, PSE&G has not yet completed the cost-effectiveness analysis, which requires extensive data compilation and modeling.

19. Contained herein as Attachment D is a draft Form of Notice of Filing and of Public Hearings. This Form of Notice sets forth the requested changes to the electric rates and will be placed in newspapers having a circulation within the Company's electric service territory upon receipt, scheduling and publication of public hearing dates. One public hearing will be held in each geographic area within the Company's service territory, i.e. Northern, Central, and Southern. Concurrent with this filing with the BPU, a Notice of this filing will be served on the County Executives and Clerks of all Municipalities within the Company's electric service territory. A subsequent Notice will be served on the County Executives and Clerks of all Municipalities within the Company's electric service territory upon receipt, scheduling and publication of public hearing dates. (See Attachment E) Two copies of the Petition and supporting attachments will be served upon the Department of Law and Public Safety, 124 Halsey Street, P.O. Box 45029, Newark, New Jersey 07102 and upon the Director, Division of

Rate Counsel, 31 Clinton Street, Newark, New Jersey 07101. A copy will also be sent to the persons identified on the service list provided with this filing.

20. Public Service requests that the proposed rates to recover all of the Demand Response Program costs be approved by the Board, along with the Demand Response Program and cost recovery mechanism proposed in this filing, within the timeframe established by the Board as set forth in Exhibit A of the Board's Demand Response Order. Public Service also requests that the Board authorize the Company to implement the proposed rates contemporaneously with the Board's approval of this Petition. Once the proposed RRC rates are in effect, the RRC will operate much like the Company's other rate clauses, subject to deferred accounting and periodic true-up through filings with the Board.

21. PSE&G is not requesting recovery of foregone distribution fixed cost contributions (i.e., "lost revenues") for any of subprograms within its Demand Response Program at this time. However, PSE&G reserves its right to seek such lost revenue recovery for quantifiable and measurable foregone distribution fixed cost contributions in the future.

REQUEST FOR REVIEW AND APPROVAL

22. Public Service requests review and approval of this Petition pursuant to the procedural schedule set forth in Exhibit A of the Board's Demand Response Order.

23. In order to achieve the timeline established in Exhibit A of the Board's Demand Response Order, Public Service respectfully requests that the BPU retain jurisdiction of this matter and not transfer the filing to the Office of Administrative Law. PSE&G believes evidentiary hearings are not required for the Board to approve this Demand Response pPprogram and related authorizations. Public Service is confident that these and any issues other parties raise can be resolved through settlement or through written comments filed with the Board prior to its decision.

CONCLUSION

For all the foregoing reasons, PSE&G respectfully requests that the Board retain jurisdiction of this matter and review and issue an Order approving this Petition, specifically finding that:

1. The Demand Response Program is in the public interest and that PSE&G is authorized to implement and administer these regulated utility services under the terms set forth in this Petition and accompanying Attachments;

2. The cost recovery mechanism proposed herein is just and reasonable, and PSE&G is authorized to recover all costs requested herein associated with the Demand Response Program, which will be recovered through a separate demand response component of the electric RGGI Recovery Charge, which will be filed annually;

3. All legacy Residential A/C Cycling program costs currently being recovered through the System Control Charge will now be recovered through the new

demand response component of the electric RRC; the deferred SCC balance will be transferred to the RRC and the SCC rate set to zero;

4. The proposed rates and charges, as set forth herein, are just and reasonable and PSE&G is authorized to implement the rates proposed herein.

COMMUNICATIONS

Communications and correspondence related to the Petition should be sent as follows:

Frances I. Sundheim
Public Service Electric and Gas Company
80 Park Plaza, T8C
P. O. Box 570
Newark, New Jersey 07101
Phone: (973) 430-6928
Fax: (973) 648-0838

Gregory Eisenstark
PSEG Services Corp.
80 Park Plaza, T5G
P. O. Box 570
Newark, New Jersey 07101
Phone: (973) 430-6281
Fax: (973) 430-5983

Respectfully submitted,

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Original Signed by
By: *Frances I. Sundheim, Esq.*

Frances I. Sundheim
Vice President and Corporate Rate Counsel
Public Service Electric and Gas Company
80 Park Plaza, T8C
P. O. Box 570
Newark, New Jersey 07101
Phone: (973) 430-6928
Fax: (973) 648-0838

DATED: August 5, 2008
Newark, New Jersey

STATE OF NEW JERSEY)
:
COUNTY OF ESSEX)

FRANCES I. SUNDHEIM, of full age, being duly sworn according to law, on her oath deposes and says:

1. I am Vice President and Corporate Rate Counsel of Public Service Electric and Gas Company, the Petitioner in the foregoing Petition.

2. I have read the annexed Petition, and the matters and things contained therein are true to the best of my knowledge and belief.

Original Signed by
Frances I. Sundheim, Esq.

Sworn and subscribed to)
before me this 5th day)
of August 2008)

____

APPENDIX A

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

I. General Filing Requirements

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

PSE&G provides such data in its Petition and supporting schedules.

d. The utility shall file testimony supporting its petition.

Please refer to the testimony filed in support of PSE&G's Petition.

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 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.

PSE&G is proposing a small scale program subject to Sections I, II, III and IV.

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.

PSE&G will hold three (3) public hearings in its service territory; North, Central and Southern regions; a draft notice is provided with the Petition.

II. <u>Program Description</u>

a. The utility shall provide a detailed description of each proposed program for which the utility seeks approval.

PSE&G provides this information in the Petition and Attachments

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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 <u>N.J.S.A.</u> 26:2C-42(b) and (c) and <u>N.J.S.A.</u> 26:2C-43 of the Global Warming Response Act, <u>N.J.S.A.</u> 26:2C-37 <u>et</u> <u>seq.</u>

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

PSE&G provides this information in the Petition and Attachments

g. The utility shall provide the criteria upon which it chose the program.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

PSE&G provides details of the Program costs in the workpapers

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.

PSE&G provides this information in the Petition and Attachments

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

k. The utility shall provide a detailed description of the process for resolving any customer complaints related to these programs.

PSE&G provides this information in the Petition and Attachments

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.

PSE&G provides this information in the workpapers

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

III. Additional Required Information

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

e. The utility shall provide an analysis of the benefits or impacts in regard to Smart Growth.

   Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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 to this filing

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 to this filing

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 to this filing

IV. Cost Recovery Mechanism

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.

   PSE&G provides appropriate financial data for the proposed program in the Petition and Attachments

b. The utility 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.

   PSE&G provides this information in the Petition and Attachments

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.

PSE&G provides this information in the Petition and Attachments

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.

PSE&G's Petition is verified as to its accuracy, and PSE&G will serve a copy of the filing on the Department of Public Advocate, Division of Rate Counsel

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 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.

PSE&G provides rate impact information for its proposed DR Program in the Petition and Attachments

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.

PSE&G provides this information in the Petition and Attachments

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.

PSE&G provides this information in the Petition and Attachments

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.

Due to the accelerated timeframe BPU Staff has directed for this filing, this item was identified at the pre-filing meeting as information that would not be required.

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.

PSE&G provides this information in the Petition and Attachments

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.

PSE&G is not proposing a decoupling mechanism as part of this filing. PSE&G is proposing to share with ratepayers certain demand response payments received from PJM for certain programs, as discussed in the Petition and Attachments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
FREDERICK A. LYNK
MANAGER OF MARKET STRATEGY AND PLANNING

My name is Frederick A. Lynk, and I am the Manager of Market Strategy and Planning in the Renewables and Energy Solutions Group at Public Service Electric and Gas Company (PSE&G, the Company). My credentials are set forth in the attached Schedule FAL-1.

SCOPE OF TESTIMONY

I am testifying in support of PSE&G's proposed Demand Response Program (Program), comprised of five sub-programs targeted at various customer segments. I provide a description of each of the sub-programs. I also testify in support of PSE&G's proposal regarding resolution of customer complaints or disputes that arise regarding the Demand Response Program.

The electronic version of this filing contains the Program assumptions including investments, costs, participation, incentives, market sizing, and impacts in the electronic workpaper labeled WP_FAL 1.xls.

DEMAND RESPONSE PROGRAM

PSE&G is proposing a Demand Response Program consisting of five sub-programs. In this section of my testimony, I describe each sub-program. Please note that the target dates referenced in my testimony are subject to the assumption that a written Board Order approving the Program is received in November 2008.

Residential Central Air Conditioner (AC) Cycling Sub-Program

Description

This residential sub-program involves replacing all switches and thermostats currently in the legacy "Cool Customer" program with new upgraded devices. The oldest controls in the legacy program were installed in 1990, and most are beyond their assumed useful life of 15 years. By the end of the five-year replacement sub-program proposed here, all legacy program devices will be beyond their useful life and require replacement. Therefore, for each device that is replaced, PSE&G will claim an impact of 0.72 kW in the analysis for this sub-program's impact. This sub-program will also be opened up to new participants. Either cycling switches or thermostats will be installed at the customer's option. PSE&G will specify equipment that is compatible or that can be readily made compatible with Advanced Metering Infrastructure (AMI) systems that might ultimately be installed by PSE&G. Cost recovery will be through a new component of the proposed electric

RGGI Recovery Charge (RRC), as discussed in the testimony of Stephen Swetz (Attachment B to this filing). All legacy program costs currently being charged to the System Control Charge (SCC) will be charged to the RRC, but have not been reflected here as part of the budget to develop this new sub-program. Legacy costs will be ramped down as legacy devices are replaced.

Target Market and Eligibility

PSE&G proposes to target delivery of load control capacity comprising 17% of the eligible residential market (residential customers with central air conditioners) over the next five years including replacement/upgrade of existing legacy load control equipment and new participants. This represents a replacement of existing controls and expansion to new participants to reach a target of 168,300 residential customers representing 181,764 controls over the long-run.

	2009	2010	2011	2012	2013
Transfer Legacy participants	**9,463**	**17,743**	**30,754**	**30,754**	**29,571**
New Participants	**4,001**	**7,503**	**13,004**	**13,004**	**12,505**
Total Participants Added	**13,464**	**25,246**	**43,758**	**43,758**	**42,076**
Cumulative Participants	**13,464**	**38,710**	**82,468**	**126,226**	**168,302**

Communications signal strength, age and condition of the current air conditioner and the control devices will be among the screening criteria for all candidates. Marketing will initially target existing residential program participants with older switches in order to change them to new switches or new thermostats.

Offerings and Customer Incentives

Residential customers in the legacy program with switches will be provided a new one-way switch. Customers in the legacy program with existing thermostats will be offered thermostats. New customers will be offered a choice between a switch or a thermostat.

As recognized by Summit Blue in its Final Report, equipment and communication technologies that support demand response (DR) system controls are in a stage of significant innovation nationally that will require an appropriate level of flexibility, demonstration and evaluation. Direct Load Control (DLC) communications currently rely on Electric Distribution Company (EDC) voice communications infrastructure. Any changes to load management communications must align with Federal Communications Commission requirements, system controls and AMI deployment. The technologies selected will have to be adaptable to the new communications options.

For customers with switches, PSE&G will maintain the current incentives ($4 per month for the four summer months plus $1 per event). For modeling purposes, PSE&G assumed seven events per year. For customers with thermostats, PSE&G will provide and install the thermostat for free and provide a $50 signing bonus for new customers, however, there will be no ongoing incentive.

Sub-Program Administration

PSE&G will perform sub-program administration. It will develop an appropriate tracking system, develop marketing materials, interact with PJM for nomination into PJM DR programs and markets, and pay customer incentives through its billing system.

Sub-Program Delivery Methods

PSE&G intends to utilize its own workforce for the delivery of this sub-program. PSE&G may also utilize subcontractors as needed. In the event that subcontractors are utilized, for the purposes of this sub-program, for those projects that qualify as a "public work" as defined by statute, the service provider will adhere to all aspects of the New Jersey State Prevailing Wage Act, *N.J.S.A.* 34:11-56.25 et seq., and will require the same of all subcontractors. For those projects that do not qualify as public works, service providers will be required to pay the equivalent of the prevailing wage for the county in which the work is to be performed, unless the work is performed by union employees, in which case the employees will be paid in accordance with the union contract.

PSE&G has not yet identified areas where PSE&G will need sub-contractors and therefore, has not yet developed specific criteria for selection. If needed, sub-program and skill-specific qualifications will be developed and an RFP will be issued to advertise the competitive opportunity. Selection criteria typically includes overall quality, completeness and responsiveness to the RFP; quality of approach; prior experience; and cost.

Given the nature of the work to be done and the lead times required for the development of a competitive solicitation for equipment, and the time needed to actually manufacture the new devices, it is anticipated that the first installations would begin in June 2009, and the first incremental sub-program impacts would be available for nomination into the PJM DR programs for the Energy Year (EY) commencing June 1, 2010.

Replacement of Legacy Controls

Since the equipment is at the end of its useful life, rather than attempt to locate existing missing or inoperable legacy controls, PSE&G will replace existing equipment in a systematic manner over a five-year period.

Installation of Devices for New Participants

At the same time that PSE&G is replacing existing equipment, it will be offering the sub-program to new participants. New devices will be installed by PSE&G.

Procurement of Replacement and New Controls

PSE&G will utilize a competitive process for the procurement of equipment and technology for this sub-program.

Marketing

PSE&G will communicate with existing participants about its plans to migrate the legacy program to this new sub-program. These communications will inform customers of PSE&G's plans to replace existing equipment and solicit their approval to continue in the sub-program.

PSE&G will also market the sub-program to new customers. This will be done using a combination of bill inserts, direct mail and telemarketing, similar to the marketing methods PSE&G has utilized in the past for energy efficiency programs.

Cycling Operations

For the EY commencing on June 1, 2009, under both the legacy Residential AC Cycling Program and for the new sub-program, PSE&G will continue to initiate up to 20 cycling events for reliability support and economic energy management using the following criteria:

1) PJM's declaration of a system emergency; or
2) Local distribution emergencies; or

3) A combination of a high Weighted Temperature Humidity Index (WTHI) of at least 80, with high Locational Marginal Prices (LMP) of at least $250/MWh forecasted for the day-ahead PJM market (average value over the period between 2PM and 4PM) in the PS Zone.

Cycling duration is expected generally to be up to six hours, but longer durations may be required under certain limited circumstances in the event of system emergencies. Annually thereafter, PSE&G will conduct an assessment to establish criteria for subsequent years.

PSE&G will nominate the sub-program into appropriate PJM DR programs and markets as determined by PSE&G. For rate impact modeling purposes, nomination into the Interruptible Load for Reliability (ILR) Program was assumed.

PSE&G will utilize records from inspections performed under the existing legacy program, as well as any installations under the new sub-program to document system operability and incorporate revised operability data for registering the sub-program starting with the EY commencing June 1, 2010.

Quality Assurance Provisions

PSE&G will perform periodic inspections of the switch and thermostat population until such time as AMI is deployed on a wide-scale basis. This may be done on a sampling basis. Once AMI and its two-way communication system is in place, it will not be necessary to determine which devices are operating by making field visitations.

Effectiveness Measures

Until AMI becomes available, PSE&G will rely on load studies that are acceptable to PJM. The current estimated load response impact per control is based upon values published in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in the PJM Region," Executive Summary (See Schedule FAL-2).

The current load response impact per control accepted by PJM is based on an average of the impact for high use customers (>1600kWh per summer month). High use customers have an estimated impact of 1.03 kW per control and the moderate use customers have an estimated impact of 0.48 kW per control, yielding the blended rate of 0.72 kW per control. These impacts are based on load control with no adjustment for line loss or operability.

For every device that is replaced by PSE&G, an impact of 0.72 kW will be claimed towards the BPU's goals for Demand Response.

Budget

The proposed budget is set forth in Schedule SS-3a to the testimony of Stephen Swetz (Attachment B).

Residential Pool Pump Load Control Sub-Program

Description

There are an estimated 65,000 swimming pools in PSE&G's service territory. One device that is feasible for load control is the pool's pump, which on average is ¾ horsepower. PSE&G plans to target pool owners to enroll them in a program that will operate under parameters similar to the Residential AC Cycling Sub-Program. PSE&G will install a cycling switch on the pool pump and cycle it at the same time as its Residential AC Cycling Sub-Program.

Cost recovery will be through a new component of the RGGI Recovery Charge (RRC), as discussed in the testimony of Stephen Swetz. (Attachment B)

Target Market and Eligibility

Customers with pool pumps of at least ½ horsepower will be targeted. Pumps for above-ground, as well as, in-ground pools are eligible. PSE&G estimates that there are approximately 65,000 pool pumps in its service territory. Based on prior marketing experience, PSE&G has assumed that 5% of eligible customers will participate. Pool pump installations will commence in June 2009 and will have an impact in the EY commencing June 1, 2010. Expected per unit savings are 0.75 kW.

Offerings and Customer Incentives

PSE&G will pay customers a financial incentive of $4 per device in the billing months of June, July, August and September, with an additional $1 per event paid in October.

Sub-Program Administration

PSE&G will perform all aspects of program administration including program management, tracking, marketing, installation and maintenance of cycling devices and program evaluation. It will also register the program with PJM in its DR markets.

Sub-Program Delivery Methods

PSE&G intends to install all equipment on the customer's premises. PSE&G may also utilize subcontractors as needed. In the event that subcontractors are utilized, for the purposes of this sub-program, for those projects that qualify as a "public work" as defined by statute, the service provider will adhere to all aspects of the New Jersey State Prevailing Wage Act, *N.J.S.A.* 34:11-56.25 et seq., and will require the same of all subcontractors. For those projects that do not qualify as public works, service providers will be required to pay the equivalent of the prevailing wages for the county in which the work is to be performed, unless the work is performed by union employees, in which case the employees will be paid in accordance with the union contract.

PSE&G has not yet identified areas where PSE&G will need sub-contractors and therefore, has not yet developed specific criteria for selection. If needed, sub-program and skill-specific qualifications will be developed and an RFP will be issued to advertise the competitive opportunity. Selection criteria typically includes overall quality, completeness and responsiveness to the RFP; quality of approach; prior experience; and cost.

Procurement of Replacement and New Controls

The equipment to be selected will be through a competitive procurement process. Given the lead time associated with developing a competitive procurement and awarding a contract, as well as the time required to manufacture the cycling devices, the first installations are anticipated to start in June 2009.

Marketing

PSE&G will market this sub-program to customers using a combination of direct mail and telemarketing, similar to the marketing methods PSE&G has utilized in the past for energy efficiency programs.

Cycling Operations

For the EY commencing on June 1, 2009, PSE&G will initiate up to 20 cycling events for reliability support and economic energy management using the following criteria:

1) PJM's declaration of a system emergency; or
2) Local distribution emergencies; or
3) A combination of a high WTHI of at least 80, with high LMP of at least $250/MWh forecasted for the day-ahead PJM market (average value over the period between 2PM and 4PM) in the PS Zone.

For this sub-program, the Company will utilize a 100% duty cycle strategy. Cycling duration is expected generally to be up to six hours but longer durations may be required under certain limited circumstances in the event of system emergencies. Annually thereafter, PSE&G will conduct an assessment to establish criteria for subsequent years.

PSE&G will nominate the sub-program into appropriate PJM DR programs and markets as determined by PSE&G. For rate impact modeling purposes, nomination into the ILR program was assumed.

Quality Assurance Provisions

Please refer to the description for the Residential AC Cycling Sub-Program.

Effectiveness Measures

PSE&G intends to use a 100% duty-cycle strategy for each curtailment. That means for the duration of the event, the pool will be completely shutdown, rather than cycled on and off as is the case with the AC Cycling program. The net shut down expected impact will be 0.75 kW per device installed.

PSE&G will perform a load study that will be used to support the nomination of this program into the PJM DR markets, by metering a few customer installations. For the initial nomination into the PJM programs, PSE&G proposes to use an assumed impact of 0.75 kW per device, which is an engineering estimate of the electricity demand for a ¾ hp motor.

Budget

The proposed budget is set forth in Schedule SS-3b to the testimony of Stephen Swetz. (Attachment B)

<u>Small Commercial Customer AC Cycling Sub-Program</u>

Description

This sub-program will offer direct load devices (either a switch or thermostat, exact technology to be determined) to small commercial customers. As part of its myPower Link pilot program, PSE&G tested the feasibility of offering a utility-activated load management program to small commercial customers.

PSE&G intends to use a cycling strategy rather than a temperature setback approach. Despite the different strategy, the demand reduction impact is expected to be similar to that achieved by the myPower Pilot. The estimated impact (average kW per hour) for the small commercial segment, with a 2 to 4 degree setback showed an impact of 1.66 kW at 95^{o}F.[1]

Customers in this sub-program will not be able to override curtailments, at least not until AMI-enabled two-way communications become available.

Cost recovery will be through a new DR component of electric RRC, as discussed in the testimony of Stephen Swetz (Attachment B).

PSE&G will nominate this sub-program into the appropriate PJM DR program.

Target Market and Eligibility

Small commercial customers on the General Lighting and Power (GLP) rate schedule with curtailable loads such as air conditioning will be eligible to participate.

Offerings and Customer Incentives

PSE&G will offer incentives of $7.50 a month in each of the summer months of June, July, August and September for each device installed.

[1] "Final Report for the myPower Link Utility Activated Load Management Pilot Program," Summit Blue Consulting, Boulder CO, Executive Summary page XVII (See Schedule FAL-3).

Sub-Program Administration

PSE&G will perform all aspects of program administration including program management, tracking, marketing, installation and maintenance of cycling devices and program evaluation.

Sub-Program Delivery Methods

PSE&G intends to install all equipment on the customer's premises. PSE&G may also utilize subcontractors as needed. In the event that subcontractors are utilized, for the purposes of this sub-program, for those projects that qualify as a "public work" as defined by statute, the service provider will adhere to all aspects of the New Jersey State Prevailing Wage Act, *N.J.S.A.* 34:11-56.25 et seq., and will require the same of all subcontractors. For those projects that do not qualify as public works, service providers will be required to pay the equivalent of the prevailing wages for the county in which the work is to be performed, unless the work is performed by union employees, in which case the employees will be paid in accordance with the union contract.

PSE&G has not yet identified areas where PSE&G will need sub-contractors and therefore, has not yet developed specific criteria for selection. If needed, sub-program and skill-specific qualifications will be developed and an RFP will be issued to advertise the competitive opportunity. Selection criteria typically includes overall quality, completeness and responsiveness to the RFP; quality of approach; prior experience; and cost.

Procurement of Replacement and New Controls

The equipment will be selected through a competitive procurement process. Given the lead time associated with developing a competitive procurement and awarding a contract as well as the time required to manufacture the cycling devices, the first installations are anticipated to start in June 2009.

Marketing

PSE&G will market this sub-program to customers using a combination of direct mail and telemarketing, similar to the marketing methods PSE&G has utilized in the past for energy efficiency programs.

Cycling Operations

For the EY commencing June 1, 2009, this sub-program will be operated in a manner similar to the Residential AC Cycling Sub-Program for residential customers. PSE&G will initiate up to 20 cycling events for reliability support and economic energy management using the following criteria:

1) PJM's declaration of a system emergency; or
2) Local distribution emergencies; or

3) A combination of a high WTHI of at least 80, with high LMP of at least $250/MWh forecasted for the day-ahead PJM market (average value over the period between 2PM and 4PM) in the PS Zone.

Cycling duration is expected generally to be up to six hours, but longer durations may be required under certain limited circumstances in the event of system emergencies.

This sub-program will be nominated into the appropriate PJM DR programs and markets as determined by PSE&G.

Quality Assurance Provisions

PSE&G will continue to perform periodic inspections of the control devices until such time as AMI is deployed on a wide-scale. This may be done on a sampling basis. Once AMI and its two-way communication system is in place, it will not be necessary to determine which devices are operating by making field visitations, as the AMI communications system will provide this capability.

Effectiveness Measures

PSE&G will perform a load study that will be used to support the nomination of this sub-program into the PJM DR programs and markets. The initial impact will be valued based upon the myPower Link results (See Schedule FAL-3).

Budget

The proposed budget is set forth in Schedule SS-3c to the testimony of Stephen Swetz. (Attachment B)

<u>Commercial and Industrial (C&I) Curtailment Services Sub-Program</u>

Description

The C&I Curtailment Services Sub-Program is designed to interest and enroll eligible mid-size to large C&I customers in PJM's demand response programs. PSE&G will register with PJM to become a Curtailment Service Provider (CSP) and offer demand reduction services to this market segment. All participants must agree to participate in the PJM DR programs for a period of five years. All customers must develop a Technical Assessment to determine the exact demand reduction. PSE&G will assist customers in developing a reliable capability of demand response and will provide necessary engineering and installation services for enabling equipment. Customers must be able to reduce load by a minimum of 100 kW during periods of high demand in response to notification from PSE&G. Customers will be paid $100 per kW to help defray their initial cost of installing enabling technology. Customers will also receive a payment of $5.00 per kW of scheduled demand reduction during the billing months of June, July, August and September for as long as they are enrolled in a PJM demand response program.

Cost recovery will be through a new DR component of the electric RRC, as discussed in the testimony of Stephen Swetz. (Attachment B)

Target Market and Eligibility

The target market for this sub-program is commercial and industrial customers most able to undertake demand response actions. These include Basic Generation Service (BGS) CIEP customers and BGS FP customers served on Rate Schedule LPL-S. Customers who agree to reduce their electric load by a minimum of 100 kW during periods of high system demand and during high cost periods are eligible to participate. Customers must also have interval metering installed in order to determine compliance with PJM and PSE&G requests for curtailment of loads.

Offerings and Customer Incentives

PSE&G will provide a one-time financial incentive of $100 per kW of demand response to customers who agree to participate in the PJM DR programs for a period of five years. The incentive payment is to help pay for their initial costs required to prepare a customer's facility for reliable participation in PJM programs. Payments will be made directly to the customer.

Payments will be made only after the load reduction capability has been ascertained by PSE&G and accepted by PJM.

In addition to the upfront payment, PSE&G will pay each participating customer $1.00 per kW scheduled demand reduction for each of the months of June, July, August and September.

PSE&G will assist a customer, free-of-charge, in developing the required Technical Assessment. Engineering services, as well as equipment installation, will also be offered, if necessary.

Sub-Program Administration

PSE&G will register as a Curtailment Service Provider in order to register participating customers in the appropriate PJM DR markets and programs.

Sub-Program Delivery Methods

PSE&G intends to use its own labor to perform required engineering assessments and any installation work that the customer wants PSE&G to perform. PSE&G may also utilize subcontractors as needed. In the event that subcontractors are utilized, for the purposes of this sub-program, for those projects that qualify as a "public work" as defined by statute, the service provider will adhere to all aspects of the New Jersey State Prevailing Wage Act, *N.J.S.A.* 34:11-56.25 et seq., and will require the same of all subcontractors. For those projects that do not qualify as public works, service providers will be required to pay the equivalent of the prevailing wage for the county in which the work is to be performed, unless the work is performed by union employees, in which case the employees will be paid in accordance with the union contract.

PSE&G may contract with third-parties for the provision of certain Curtailable Service Provider functions, such as the monitoring of the PJM markets on a 24/7 basis. PSE&G will also manage customer relationships throughout the life of the sub-program to make sure that the load reduction capability is maintained.

PSE&G has not yet identified areas where PSE&G will need sub-contractors and therefore, has not yet developed specific criteria for selection. If needed, sub-program and skill-specific qualifications will be developed and an RFP will be issued to advertise the competitive opportunity. Selection criteria typically includes overall quality, completeness and responsiveness to the RFP; quality of approach; prior experience; and cost.

Marketing

PSE&G will market the program extensively and will make sales presentations to targeted and interested customers.

Quality Assurance Provisions

PSE&G will also use its workforce to verify the feasibility of customers to reliably curtail load in accordance with the Technical Assessment that customers will submit as a requirement of program participation.

Effectiveness Measures

Periodic audits will be conducted to assure that participating customer load reductions are reliable. These audits entail site visits to customer facilities.

Budget

The proposed budget is set forth in Schedule SS-3d to the testimony of Stephen Swetz. (Attachment B)

Load Shifting Demonstration Sub-Program

Description

PSE&G will conduct several demonstration trials designed to effect load shifting. The sub-program will have four components: energy storage using a battery; Coolness Storage; plug-in hybrid electric vehicles (PHEVs); solar street lighting.

Two of the demonstration trials contemplated here involve the use of technologies to effect load shifting in constrained areas of the distribution system.

The first is to install a large storage battery, in the range of 500kW, on the utility side of the meter. The second would be to locate a commercial or industrial customer with the potential to utilize Coolness Storage, and work with the customer to develop that capability.

PSE&G will conduct an evaluation to determine the effectiveness of these technologies in shifting loads to reduce demand on the distribution system and to determine what effect such technologies can have to delay traditional infrastructure investments.

There are several different strategies that will be tested and evaluated. For example, the battery storage device could be set up to respond to hourly LMPs. Alternatively, the system could be used in conjunction with day-ahead prices, and used to respond to deviations (spikes) in real-time prices. There are a number of different approaches, including using "trigger points," i.e. having the system start when the price is expected to go above a certain level, or when the circuit load reaches a pre-established level.

The PHEV trial entails PSE&G's involvement with the Electric Power Research Institute (EPRI) and the Ford Motor Company on a major demonstration of Original Equipment Manufacturer (OEM) light-duty PHEVs. PSE&G will have access to one or more prototype vehicles. The sub-program deliverables include development of a detailed analysis of the major components of the PHEV value equation and business case. This sub-program will involve participation in a demonstration/data collection effort of eight to ten PHEV Ford Escape vehicles (PSE&G is expected to receive two to three of these vehicles for its use) in the New York/New Jersey area through June 2012. The vehicles will be shared among utility fleets and will include residential customer demonstrations, data collection, customer use, adoption studies and smart charging. The dollar expenditures will be used to fund the collaborative research program, charging station installation, data collection, and preparation of a final report. By using the vehicles and getting to know their characteristics and how they will integrate into the PSE&G distribution system, PSE&G will be able to better prepare for PHEV commercialization.

The solar street lighting project involves PSE&G's testing of a prototype form of street lighting using solar energy. PSE&G will work with a manufacturer to develop and test street lighting fixtures that will have integrated solar panels. During daylight hours, the unit will put energy into the grid and at night, it will draw energy from the grid to power the street light.

Target Market and Eligibility

Coolness Storage is the only component of this sub-program that must be actively marketed to customers. This component will involve customers with the capability to utilize Coolness Storage, if they are located in a constrained distribution area.

Offerings and Customer Incentives

Coolness Storage is the only component of this sub-program that offers incentives to customers. An appropriate level of incentives in Coolness Storage trials will be determined after targeted customers have been approached and viable projects developed. For modeling purposes, the sub-program incorporates $1 million in incentives.

Sub-Program Administration

PSE&G will be the project manager for all sub-program components.

Sub-Program Delivery Methods

PSE&G intends to use its own labor to perform installation work. PSE&G may also utilize subcontractors as needed. In the event that subcontractors are utilized, for the purposes of this sub-program, for those projects that qualify as a "public work" as defined by statute, the service provider will adhere to all aspects of the New Jersey State Prevailing Wage Act, *N.J.S.A.* 34:11-56.25 et seq., and will require the same of all subcontractors. For those projects that do not qualify as public works, service providers will be required to pay the equivalent of the prevailing wages for the county in which the work is to be performed, unless the work is performed by union employees, in which case the employees will be paid in accordance with the union contract.

PSE&G has not yet identified areas where PSE&G will need sub-contractors and therefore, has not yet developed specific criteria for selection. If needed, sub-program and skill-specific qualifications will be developed and an RFP will be issued to advertise the competitive opportunity. Selection criteria typically includes overall quality, completeness and responsiveness to the RFP; quality of approach; prior experience; and cost.

Marketing

Coolness Storage is the only component of this sub-program that must be marketed to customers. Direct sales contact will be used to develop an appropriate site for the Coolness Storage demonstration.

Quality Assurance Provisions

PSE&G will install the energy storage battery and solar streetlights and be an active participant in the PHEV demonstration with EPRI and Ford. It will also work closely with the Coolness Storage project while it is developed by a customer.

Effectiveness Measures

For the energy storage battery, Coolness Storage, and solar street lighting components, evaluations will be performed on all the projects. For PHEV, the result will be a report prepared by EPRI.

Budget

PSE&G is proposing to commit $6.0 million, as set forth in Schedule SS-3e to the testimony of Stephen Swetz (Attachment B), in investments toward the delivery of this DR subprogram. The specific investments are as follows:

- Energy Storage using a Battery: $3.0 million
- Coolness Storage: $1.0 million
- Plug-in Hybrid Vehicles: $1.5 million (for modeling purposes, this amount is incorporated in administrative costs)
- Solar Street Lighting: $0.5 million

DISPUTE RESOLUTION PROCEDURES

Customer complaints relating to the design, delivery, or administration of the PSE&G's sub-programs potentially could be received through two means: directly to various PSE&G customer contact personnel and departments or directly to the NJBPU. In both instances the immediate issue would be referred to the appropriate management personnel to investigate and resolve. PSE&G will utilize the same complaint resolution procedures in the Demand Response Program that were approved for use in the Solar Loan Program. PSE&G will attempt to resolve disputes with its customers informally in the first instance. See Schedule FAL-4 for a flow chart on how customer complaints will be processed. Disputes that involve PSE&G's administration of the Program that cannot be resolved informally will be resolved through the BPU's existing process for customer complaints within the appropriate Division. Disputes between PSE&G and its sub-contractors will be resolved in accordance with contract provisions. Disputes under the Program that involve monetary claims or civil damages that cannot be decided by the NJBPU will be resolved in an appropriate court of law.

This concludes my testimony at this time.

QUALIFICATIONS OF FREDERICK A. LYNK MANAGER OF MARKET STRATEGY AND PLANNING

Educational Background

I graduated from Clarkson University in 1969 with a Bachelor of Science Degree in Industrial Distribution. In 1974, I earned the degree of Master of Business Administration from Rutgers University. I attended the Executive Management Program at Pennsylvania State University in 1984.

Work Experience

From 1969 to 1980 I held several positions including Marketing Engineer, Applications Engineer, and Assistant Manager - Marketing. All of these were in the Marketing Department of PSE&G. From 1980 to 1983 I served as District Manager - Marketing of the Cranford District Office. In this capacity I supervised a regional sales force selling utility products. This sales force included several Marketing Engineers with customer account responsibility for large Commercial and Industrial Customers. I also managed the new business customer service function. In 1983 I was promoted to Manager - Industrial and Commercial Marketing in PSE&G's General Office, where I developed annual marketing plans for Commercial and Industrial market segments. In this position, I supervised several Applications Engineers. From 1986 to 1994 I was Manager - DSM Core Programs. This involved the design, implementation and evaluation of DSM programs, and managing the delivery of the programs to the marketplace through third party contractors. I launched several new programs including programs for residential new construction and a comprehensive low-income program. I also assisted in the development of PSE&G's Standard Offer Program. From 1995 through 1999 I held positions in the Marketing Department at both PSE&G and PSEG Energy Technologies. Late in 1999, I was employed by PSEG Services Corporation to develop and market PSE&G's Energy Efficiency and Renewable Energy Programs. In 2000 I was reassigned to PSE&G in the same capacity. I am currently responsible for program design and marketing of clean energy programs and initiatives at PSE&G.

From 1996 to 1997 I was a founding Board Member of the Northeast Energy Efficiency Partnerships, Inc., a non-profit regional organization that seeks to increase and coordinate energy efficiency efforts in New England, New York and the mid-Atlantic region. From 2000 to June, 2008, I served as a member of the Board of Directors of the Consortium for Energy Efficiency, a national non-profit corporation that actively promotes the use of energy-efficient products and services. I have also been a member of the Clean Energy Council which advises the NJ Board of Public Utilities on clean energy programming.

Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region

Final Report
(Revised 04-03-07)

RLW Analytics

March 2007

Prepared for

PJM Load Analysis Subcommittee
&
Charles Goldman
Lawrence Berkeley National Laboratory

Prepared by
RLW Analytics
2 Hyde Road
Clarklake, MI 49234
517 529 6277
curt@rlw.com

Executive Summary

Background

During 2005 and 2006, the PJM Interconnection (PJM) Load Analysis Subcommittee (LAS) examined ways to reduce the costs and improve the effectiveness of its existing measurement and verification (M&V) protocols for Direct Load Control (DLC) programs.[1] The current M&V protocol requires that a PURPA-compliant Load Research study be conducted every five years for each Load-Serving Entity (LSE). The current M&V protocol is expensive to implement and administer particularly for mature load control programs, some of which are marginally cost-effective. There was growing evidence that some LSEs were mothballing or dropping[2] their DLC programs in lieu of incurring the expense associated with the M&V.

This project had several objectives: (1) examine the potential for developing deemed savings estimates acceptable to PJM for legacy air conditioning and water heating DLC programs, and (2) explore the development of a collaborative, regional, consensus-based approach for conducting monitoring and verification of load reductions for emerging load management technologies for customers that do not have interval metering capability.

Approach

The deemed savings estimates presented in this study are based on historical end-use metered data available across several jurisdictions. Air conditioning end-use metered data were received from Baltimore Gas and Electric (BGE), FirstEnergy (FE), and Public Service Electric and Gas (PSE&G). Water heating end-use metered data were provided by Baltimore Gas and Electric. Duty cycle models were constructed to examine a wide range of potential switch cycling strategies (27%, 43%, 50%, 67%, 75%, 87% and 100%).[3] Customer segmentation based on air conditioning size (e.g., connected load or seasonal usage) can also be accommodated with the model set. Next, the estimates of the customer's demand saving were mapped to their appropriate weather stations. Finally, regression analysis was conducted to predict the demand savings estimates from weighted temperature humidity indices. The demand savings predictions were tabularized for use by the participating utilities.

Air Conditioning Direct Load Control: Deemed Savings Results

Table 1 presents a sample of the predictive capability of the model and shows the predicted deemed savings for various cycling strategies at varying weighted temperature humidity (THI) combinations from 60°F to 88°F for the 15 minute time period that ends at 5PM. At a THI of 84°F, the demand reduction estimate ranges from a low of 0.37 kW

---

[1] PJM Manual 19: Load Data Systems

[2] Only Baltimore Gas and Electric maintains an active load research sample on their air conditioning and water heating direct load control programs for the purpose of reporting to PJM.

[3] Using the regional models developed in this project, the project team can run any duty cycle strategy desired by project contributors including those strategies that employ an adaptive algorithm associated with newer, smarter switches.

for the 27% cycling strategy to a high of 2.06 kW at 100% cycling. The 50% cycling strategy yields an estimate of 0.80 kW. Similar summary tables are available for every 15-minute period throughout the day. Starting at a WTHI of 80°F the savings estimates are available for every 0.1°F increments. Table 2 presents the savings between 84°F and 85°F for the period ending at 5 PM.

Table 1 Deemed Savings Estimates for A/C Load Control at 15-minute period ending 5pm

	Predicted Savings at 5pm For Various Duty Cycle Strategies						
WTHI	**27%**	**43%**	**50%**	**67%**	**75%**	**83%**	**100%**
70.0	0.02	0.04	0.06	0.06	0.09	0.18	0.30
71.0	0.02	0.04	0.06	0.13	0.19	0.28	0.43
72.0	0.02	0.04	0.06	0.21	0.28	0.38	0.55
73.0	0.02	0.09	0.13	0.29	0.37	0.48	0.68
74.0	0.05	0.15	0.19	0.37	0.46	0.58	0.80
75.0	0.09	0.20	0.25	0.45	0.55	0.68	0.93
76.0	0.12	0.25	0.31	0.53	0.65	0.78	1.06
77.0	0.15	0.30	0.37	0.61	0.74	0.87	1.18
78.0	0.18	0.35	0.43	0.68	0.83	0.97	1.31
79.0	0.21	0.40	0.50	0.76	0.92	1.07	1.43
80.0	0.24	0.45	0.56	0.84	1.01	1.17	1.56
81.0	0.27	0.51	0.62	0.92	1.10	1.27	1.68
82.0	0.30	0.56	0.68	1.00	1.20	1.37	1.81
83.0	0.34	0.61	0.74	1.08	1.29	1.47	1.93
84.0	0.37	0.66	0.80	1.16	1.38	1.57	2.06
85.0	0.40	0.71	0.87	1.23	1.47	1.67	2.19
86.0	0.43	0.76	0.93	1.31	1.56	1.77	2.31
87.0	0.46	0.81	0.99	1.39	1.65	1.87	2.44

Table 2 Deemed Savings Estimates for A/C Load Control between 84°F and 85°F at 5pm

	Predicted Savings at 5pm For Various Duty Cycle Strategies						
WTHI	**27%**	**43%**	**50%**	**67%**	**75%**	**83%**	**100%**
84.0	0.37	0.66	0.80	1.16	1.38	1.57	2.06
84.1	0.37	0.66	0.81	1.16	1.39	1.58	2.07
84.2	0.37	0.67	0.82	1.17	1.40	1.59	2.08
84.3	0.38	0.67	0.82	1.18	1.41	1.60	2.10
84.4	0.38	0.68	0.83	1.19	1.42	1.61	2.11
84.5	0.38	0.68	0.83	1.20	1.43	1.62	2.12
84.6	0.39	0.69	0.84	1.20	1.43	1.63	2.13
84.7	0.39	0.70	0.85	1.21	1.44	1.64	2.15
84.8	0.39	0.70	0.85	1.22	1.45	1.65	2.16
84.9	0.40	0.71	0.86	1.23	1.46	1.66	2.17
85.0	0.40	0.71	0.87	1.23	1.47	1.67	2.19

Should the participating utility have the ability to differentiate their population of participating customers by size of air conditioner (i.e., based on either connected load or seasonal energy use), then alternative tables can be applied to generate more customized estimates of a/c load control savings for each utility. The models and analytical methods can support the development of any stratification based on these two variables. Current tables have been constructed for seasonal air conditioning use greater or less than 1,600 kWh and for air conditioning connected load greater or less than 3.5kW.

Table 3 Predicted A/C Load Control Reduction by Seasonal A/C Use

	Predicted Savings at 5pm For Various Duty Cycle Strategies													
	Stratum 1 AC Usage < 1,600 kWh							Stratum 2 AC Usage > 1,600 kWh						
WTHI	**27%**	**43%**	**50%**	**67%**	**75%**	**83%**	**100%**	**27%**	**43%**	**50%**	**67%**	**75%**	**83%**	**100%**
70.0	0.01	0.02	0.03	0.04	0.06	0.04	0.05	0.03	0.06	0.05	0.18	0.25	0.39	0.63
71.0	0.01	0.02	0.03	0.04	0.06	0.04	0.14	0.03	0.06	0.12	0.27	0.36	0.51	0.77
72.0	0.01	0.02	0.03	0.04	0.06	0.12	0.23	0.03	0.12	0.19	0.37	0.47	0.63	0.91
73.0	0.01	0.02	0.03	0.09	0.13	0.19	0.33	0.06	0.18	0.26	0.47	0.58	0.74	1.05
74.0	0.01	0.05	0.07	0.15	0.20	0.27	0.42	0.10	0.25	0.33	0.56	0.69	0.86	1.19
75.0	0.03	0.08	0.11	0.21	0.27	0.34	0.51	0.14	0.31	0.40	0.66	0.81	0.98	1.33
76.0	0.05	0.12	0.15	0.27	0.33	0.42	0.60	0.18	0.37	0.47	0.76	0.92	1.09	1.48
77.0	0.07	0.15	0.19	0.33	0.40	0.49	0.69	0.22	0.43	0.54	0.85	1.03	1.21	1.62
78.0	0.09	0.18	0.23	0.38	0.47	0.57	0.79	0.26	0.50	0.61	0.95	1.14	1.33	1.76
79.0	0.11	0.22	0.27	0.44	0.54	0.64	0.88	0.29	0.56	0.68	1.04	1.25	1.44	1.90
80.0	0.13	0.25	0.31	0.50	0.61	0.72	0.97	0.33	0.62	0.75	1.14	1.36	1.56	2.04
81.0	0.15	0.28	0.35	0.56	0.68	0.79	1.06	0.37	0.69	0.82	1.24	1.47	1.68	2.18
82.0	0.17	0.32	0.40	0.62	0.75	0.87	1.15	0.41	0.75	0.89	1.33	1.59	1.80	2.32
83.0	0.19	0.35	0.44	0.67	0.82	0.94	1.25	0.45	0.81	0.96	1.43	1.70	1.91	2.46
84.0	0.21	0.38	0.48	0.73	0.89	1.02	1.34	0.48	0.87	1.03	1.53	1.81	2.03	2.61
84.1	0.22	0.39	0.48	0.74	0.90	1.03	1.35	0.49	0.88	1.04	1.54	1.82	2.04	2.62
84.2	0.22	0.39	0.49	0.74	0.90	1.03	1.36	0.49	0.89	1.05	1.55	1.83	2.05	2.63
84.3	0.22	0.40	0.49	0.75	0.91	1.04	1.37	0.50	0.89	1.06	1.56	1.84	2.06	2.65
84.4	0.22	0.40	0.49	0.76	0.92	1.05	1.37	0.50	0.90	1.06	1.56	1.85	2.08	2.66
84.5	0.22	0.40	0.50	0.76	0.93	1.06	1.38	0.50	0.91	1.07	1.57	1.86	2.09	2.68
84.6	0.23	0.41	0.50	0.77	0.93	1.06	1.39	0.51	0.91	1.08	1.58	1.88	2.10	2.69
84.7	0.23	0.41	0.51	0.77	0.94	1.07	1.40	0.51	0.92	1.08	1.59	1.89	2.11	2.70
84.8	0.23	0.41	0.51	0.78	0.95	1.08	1.41	0.52	0.92	1.09	1.60	1.90	2.12	2.72
84.9	0.23	0.42	0.51	0.78	0.95	1.09	1.42	0.52	0.93	1.10	1.61	1.91	2.13	2.73
85.0	0.23	0.42	0.52	0.79	0.96	1.09	1.43	0.52	0.94	1.10	1.62	1.92	2.15	2.75
86.0	0.25	0.45	0.56	0.85	1.03	1.17	1.52	0.56	1.00	1.18	1.72	2.03	2.26	2.89
87.0	0.27	0.49	0.60	0.91	1.10	1.24	1.61	0.60	1.06	1.25	1.82	2.14	2.38	3.03

Table 3 shows the same 15-minute ending 5pm period for WTHI in the range between 70^{o}F and 87^{o}F and including separate estimates by air conditioning (A/C) energy usage stratum. For customers with a seasonal air conditioning use over 1,600 kWh, the estimated demand savings at a WTHI of 84^{o}F ranges from a low of 0.21 kW for the 27% cycling strategy to 1.34 kW for the 100% cycling strategy. For large users (i.e., those with a seasonal use greater than or equal to 1,600 kWh), the demand savings range from a low of 0.48 kW for the 27% cycling strategy to 2.61 kW for the 100% cycling strategy. To develop a specific estimate, the utility simply selects the WTHI for the appropriate hour and creates a weighted average for the appropriate cycling strategy.

To demonstrate the approach, BGE provided 2006 monthly billing data for their entire population of program participants (~220,000 customers). These data were used to develop a model for estimating the air conditioning use of each customer. Next, we calculated the number of participants above and below 1,600 kWh of estimated air conditioning for the June-September 2006 period. Approximately 76% of the current program participants were estimated to have air conditioning usage greater than 1,600 kWh with the remaining 24% using less. Applying the weights to the 84^{o}F estimate presented in Table 3 yields a load reduction estimate of 0.90 kW for the hour ending 5pm for BGE's population of DLC customers.

Similarly, Table 4 presents the predicted reduction by connected air conditioning load. For this analysis, we utilized two strata: connected demand less than 3.5 kW and greater than or equal to 3.5 kW. For the 15-minute period ending at 5pm at a THI of 84^{o}F, the predicted demand reduction associated with the smaller air conditioning units ranged from a low of 0.32 kW for the 27% cycling strategy to a high of 1.86 kW for 100% cycling. For the larger air conditioners, the savings are estimated to range from a low of 0.59 kW for the 27% cycling to 2.93 kW for 100% cycling. For comparison, the aggregate results from Table 1 were 0.80 kW for 50% cycling to 2.06 kW for 100% cycling. If the utility tracks the connected demand of their program participants then this data can be used to develop a unique estimate. To do this, the utility simply selects the WTHI for the appropriate hour and cycling strategy and creates a weighted average based on the number of units above and below a connected demand of 3.5 kW.

Table 4 Predicted A/C Load Control Reduction by Connected kW

	Predicted Savings at 5pm For Various Duty Cycle Strategies													
	Stratum 1 AC Connected Demand < 3.5 kW							**Stratum 2 AC Connected Demand > 3.5 kW**						
WTHI	**27%**	**43%**	**50%**	**67%**	**75%**	**83%**	**100%**	**27%**	**43%**	**50%**	**67%**	**75%**	**83%**	**100%**
70.0	0.02	0.04	0.05	0.05	0.08	0.16	0.28	0.04	0.08	0.07	0.10	0.20	0.27	0.49
71.0	0.02	0.04	0.05	0.12	0.17	0.25	0.39	0.04	0.08	0.07	0.22	0.33	0.41	0.67
72.0	0.02	0.04	0.05	0.19	0.25	0.34	0.50	0.04	0.08	0.16	0.34	0.46	0.56	0.84
73.0	0.02	0.08	0.11	0.26	0.33	0.43	0.61	0.04	0.16	0.25	0.45	0.59	0.71	1.02
74.0	0.05	0.13	0.16	0.33	0.41	0.52	0.73	0.09	0.24	0.34	0.57	0.72	0.85	1.19
75.0	0.07	0.17	0.22	0.40	0.49	0.61	0.84	0.14	0.32	0.42	0.69	0.85	1.00	1.36
76.0	0.10	0.22	0.27	0.47	0.58	0.70	0.95	0.19	0.40	0.51	0.81	0.98	1.15	1.54
77.0	0.13	0.26	0.33	0.54	0.66	0.79	1.07	0.24	0.48	0.60	0.92	1.11	1.29	1.71
78.0	0.16	0.31	0.38	0.61	0.74	0.88	1.18	0.29	0.56	0.69	1.04	1.24	1.44	1.89
79.0	0.18	0.35	0.43	0.68	0.82	0.96	1.29	0.34	0.64	0.78	1.16	1.37	1.58	2.06
80.0	0.21	0.40	0.49	0.75	0.91	1.05	1.41	0.39	0.72	0.86	1.28	1.50	1.73	2.23
81.0	0.24	0.44	0.54	0.82	0.99	1.14	1.52	0.44	0.80	0.95	1.39	1.63	1.88	2.41
82.0	0.26	0.49	0.60	0.89	1.07	1.23	1.63	0.49	0.88	1.04	1.51	1.75	2.02	2.58
83.0	0.29	0.53	0.65	0.96	1.15	1.32	1.75	0.54	0.96	1.13	1.63	1.88	2.17	2.76
84.0	0.32	0.58	0.71	1.03	1.23	1.41	1.86	0.59	1.04	1.21	1.75	2.01	2.32	2.93
84.1	0.32	0.58	0.71	1.04	1.24	1.42	1.87	0.60	1.05	1.22	1.76	2.03	2.33	2.95
84.2	0.32	0.59	0.72	1.04	1.25	1.43	1.88	0.60	1.06	1.23	1.77	2.04	2.35	2.96
84.3	0.33	0.59	0.72	1.05	1.26	1.44	1.89	0.61	1.07	1.24	1.78	2.05	2.36	2.98
84.4	0.33	0.59	0.73	1.06	1.27	1.45	1.91	0.61	1.07	1.25	1.79	2.07	2.37	3.00
84.5	0.33	0.60	0.73	1.06	1.28	1.46	1.92	0.62	1.08	1.26	1.80	2.08	2.39	3.02
84.6	0.34	0.60	0.74	1.07	1.28	1.47	1.93	0.62	1.09	1.27	1.82	2.09	2.40	3.03
84.7	0.34	0.61	0.74	1.08	1.29	1.48	1.94	0.63	1.10	1.28	1.83	2.10	2.42	3.05
84.8	0.34	0.61	0.75	1.09	1.30	1.48	1.95	0.63	1.11	1.29	1.84	2.12	2.43	3.07
84.9	0.34	0.62	0.76	1.09	1.31	1.49	1.96	0.64	1.11	1.29	1.85	2.13	2.45	3.09
85.0	0.35	0.62	0.76	1.10	1.32	1.50	1.97	0.64	1.12	1.30	1.86	2.14	2.46	3.10
86.0	0.37	0.67	0.82	1.17	1.40	1.59	2.09	0.69	1.20	1.39	1.98	2.27	2.61	3.28
87.0	0.40	0.71	0.87	1.24	1.48	1.68	2.20	0.74	1.28	1.48	2.10	2.40	2.76	3.45

Water Heating Load Control: Deemed Savings Results

A similar duty cycle analysis was conducted for customers with direct load control of their water heaters. Table 5 summarizes the findings for the 100% cycling strategy, with average load reduction results differentiated by season (i.e., spring/fall, summer and winter) and day type (i.e., weekday or weekend) for selected hour ending time periods. For the summer weekday period at hour ending 4pm, the demand savings are estimated to be 0.24 kW. Similarly, for the winter weekday at hour ending 7am, the water heating demand savings are estimated to be 0.64 kW.

Table 5 Water Heating Load Control: Deemed Savings Estimates

		Selected Time Periods															
Season	DayType	6am	7am	8am	9am	10am	11am	12N	1pm	2pm	3pm	4pm	5pm	6pm	7pm	8pm	9pm
Spring/Fall	Weekday	0.28	0.56	0.76	0.56	0.44	0.40	0.36	0.32	0.32	0.28	0.28	0.32	0.40	0.48	0.52	0.52
Spring/Fall	Weekend	0.12	0.24	0.44	0.56	0.64	0.62	0.60	0.52	0.48	0.44	0.40	0.44	0.44	0.48	0.52	0.52
Summer	Weekday	0.24	0.44	0.56	0.44	0.36	0.32	0.28	0.28	0.24	0.24	0.24	0.28	0.32	0.36	0.40	0.40
Summer	Weekend	0.12	0.20	0.36	0.48	0.48	0.48	0.48	0.40	0.40	0.36	0.32	0.36	0.36	0.40	0.40	0.40
Winter	Weekday	0.32	0.64	0.84	0.72	0.56	0.48	0.44	0.44	0.40	0.36	0.32	0.40	0.48	0.60	0.64	0.60
Winter	Weekend	0.16	0.28	0.48	0.68	0.80	0.84	0.72	0.68	0.60	0.56	0.52	0.56	0.56	0.64	0.64	0.60

Figure 1 summarizes the time-temperature matrix created for average weekday water heating savings for selected time periods: the 15-minutes ending 7am, 8am, 9am, 5pm, 6pm and 7pm. As shown, the savings estimates decrease with increasing WTHI. These relationships were used to generate tables for each 15-minute period throughout the day and are summarized in Appendix J.

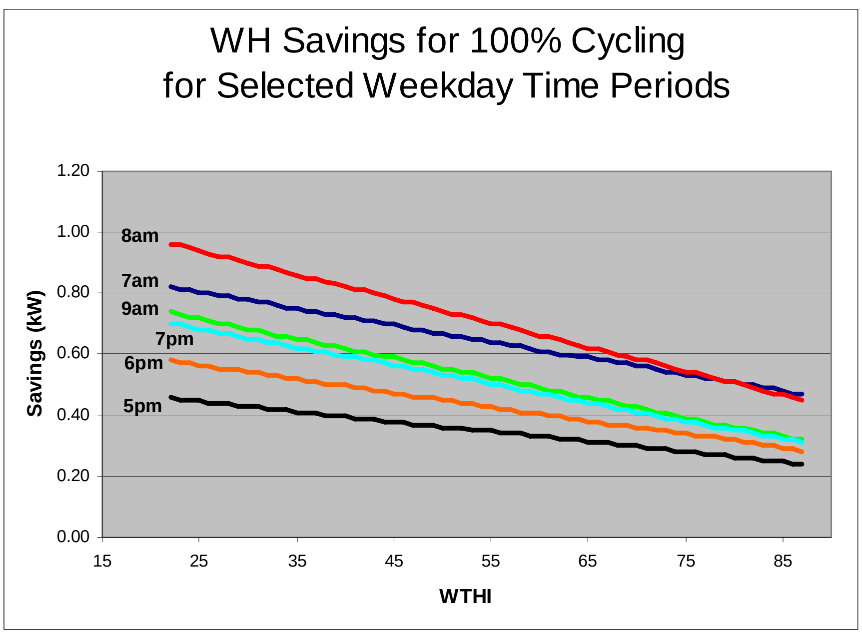


Figure 1 Water Heater Control Savings for 100% Cycling: Selected Time Periods.

Future Studies

As utilities in the PJM market footprint (see Figure 2) explore new demand response initiatives, consideration should be given to conducting regional M&V studies that effectively pool the resources of the participating utilities. The PJM market footprint is quite large (stretching from the Eastern seaboard to the western part of Illinois) with significant diversity in weather and customer household characteristics.

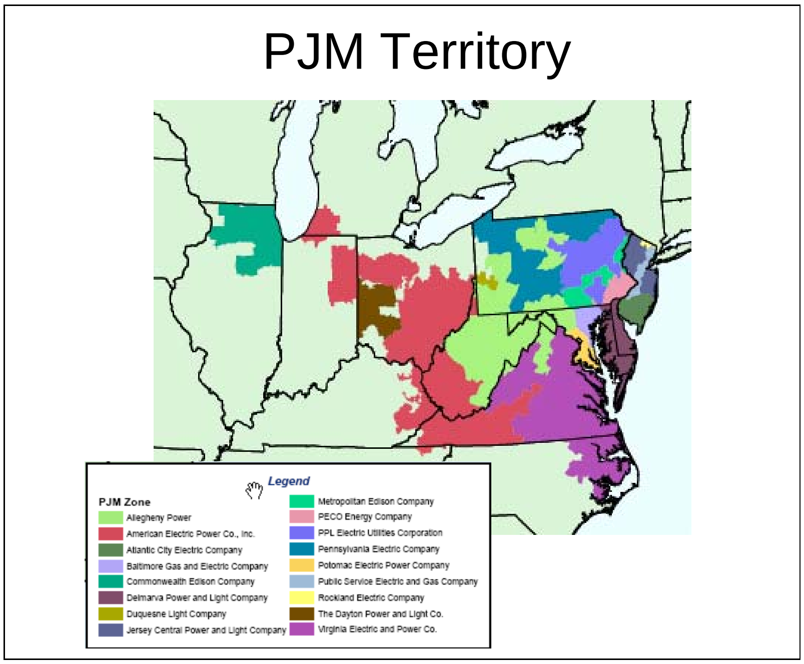


Figure 2 PJM Service Territory

We recommend a regional stratification for future studies that estimate load reductions from residential load management with sufficient sample points to meet some minimum precision criterion, e.g., 90% confidence ±20% precision, within the region. The utilities should be allowed to pool the data across the PJM footprint to improve the estimate. The specific utility would be allowed to use either unique load reduction estimates for their specific service territory, i.e., PJM zone, or the load reduction estimate from the pooled result. The key to any combined analysis is collecting consistent data across the various project components. The data elements to be included in a regional study should be clearly specified and should, at a minimum, include the following:

- End-use metered data on at least a 15-minute basis for the affected appliance;
- Total load metered data on at least an hourly basis for each residence in the end-use metered sample. Depending on the cost of data collection[4], consideration should be given to a larger total load sample of participants following a nested sampling strategy;

[4] AMI is making data collection at the whole premise level very affordable for large samples.

- Whole house consumption billing data[5] to use as an analytical link with the respective population billing systems;
- Spot wattage measurements;
- Regional weather data including at a minimum, hourly dry-bulb, hourly wet-bulb readings.

Other supporting information may prove beneficial including billing data on the population of program participants, demographic data on a large sample of program participants, and demographic data on the monitored sample.

The final deemed savings estimates should take advantage of the wealth of data collected by the contributing utilities while reflecting the unique characteristics of the specific service territory.

Operability Studies

We also recommend that each utility be required to conduct periodic operability studies, using a common sampling, testing and reporting methodology. Initially, we recommend that each utility select a simple random sample of 250 program participants and determine the operability of the control switch(s) at each sample home.[6] The testing protocol should verify both signal reception and switch operation, and identify the underlying causes of the problems that are encountered. The utility should report the overall failure rate and the appropriate net-to-gross ratio to be used to adjust the gross savings impact.

The utility-specific operability study should be conducted at least every five years, but may be conducted more frequently if a utility believes it has taken steps to mitigate its operability problems and wishes to use an improved net-to-gross ratio.

If a utility has been able to demonstrate a net-to-gross ratio of 90% or higher, then it is still required to conduct operability studies every five years, but a reduced sample size can be used. In this case the recommended sample is 100 homes.[7] If the reduced study yields an estimated net-to-gross ratio less than 90%, then we recommend that a full sample of 250 homes be tested as soon as practical and that the larger sample size be used in subsequent studies until the utility has again demonstrated a net-to-gross ratio of 90% or higher.[8]

[5] Whole premise billing information was unavailable for some of the participants included in the current analysis. This required the project team to make necessary assumptions in order to combine the data from the three service territories. Some of the concerns raised by this approach are alleviated in the stratum level analysis.

[6] A sample of 250 will give an error bound of at most ±0.05 at the 90% level of confidence for the net to gross ratio. If a tighter error bound is desired then a larger sample will be agreed to and selected.

[7] If the net to gross ratio is 0.90 or larger, a sample of 100 will give an error bound of at most ±0.05 at the 90% level of confidence for the true net to gross ratio.

[8] Our recommendations have been informed by ISO 2859-1:1999(E), "Sampling Procedures for Inspection by Attributes" which is the current version of ANSI/ASQC Z1.4.

As an initial starting point, we recommend that the utilities use the **minimum** of their last estimate or 50%. This will provide a starting point for utilities that have not conducted an operability study in the past. Here again, the utilities should be required to initiate an operability study prior to their next submittal or face a further write-down of 10% per year until the operability study is completed.

FINAL REPORT FOR THE MYPOWER LINK UTILITY ACTIVATED LOAD MANAGEMENT PILOT PROGRAM

Prepared for:

Public Service Electric and Gas Company

Prepared by:

Summit Blue Consulting
Boulder, Colorado

Contact:

Daniel M. Violette, Ph.D.
dviolette@summitblue.com
Jeff Erickson
jerickson@summitblue.com
Michael Ozog, Ph.D.
mozog@summitblue.com

December 27, 2006

EXECUTIVE SUMMARY

E.1 Introduction

The objective of the Energy Information and Control Network (EICN) pilot program ("Pilot"), marketed as myPower, is to understand the potential to create opportunities for changing the way customers think about energy delivery and consumption. The Pilot was designed to test two-way communication technologies between PSE&G and participating customers in order to transfer control instructions, energy pricing, and behavior and consumption data. The Pilot includes electric interval meters, advanced programmable thermostats, and educational materials to help customers understand how to control the timing of their energy usage. The two-way capabilities of the system can be leveraged to improve operational effectiveness and efficiency in the meter-to-bill process, outage detection, and system reliability.

The Pilot included the following segments:

Segment	Segment Name
Control Group (Residential)	Control Group
Time of Use/Critical Peak Price - Educate Only (Residential)	myPower Sense
Time of Use/Critical Peak Price - Technology Enabled (Residential)	myPower Connection
Utility Activated Load Management (Residential and Small Commercial)	myPower Link

This report presents a summary of results from the first and second seasons of operation for myPower Link (Utility Activated Load Management).

E.2 Program Description

PSE&G integrated Carrier Corporation's Comfort Choice system with participating residential and small commercial customers' central air conditioning units or electric heat pumps. The system functioned through programmable thermostats and associated communications hardware. In 2005, there were 98 residential customers with a total of 110 thermostats installed and 93 small commercial customers with 149 thermostats installed.[1] In 2006, the numbers dropped to 97 residential customers with a total of 109 thermostats installed and 90 small commercial customers with 145 thermostats installed.

The Carrier Comfort Choice product included an Internet-communicating thermostat, control software, and wireless two-way communications. PSE&G invoked a curtailment event to cycle residential central air conditioners or electric heat pumps and to set-back (increase) the thermostat temperature for central air conditioning equipment in small commercial structures during peak demand times.

Unlike the structure of the existing Residential Appliance Cycling Program (Cool Customer), customers maintained full flexibility to override curtailment events directly from their thermostat or remotely over the Internet. Analysis of data from the equipment in the myPower Link program verifies that the

[1] Three test thermostats were also installed: one each installed at PSE&G and Honeywell offices (classified as small commercial) and one installed at Carrier's office (classified as residential). The Carrier test device was re-assigned to another program on July 14, 2005.

customer's air conditioning equipment has responded to the curtailment event, thus eliminating the problem of separately identifying missing and/or inoperable switches, which has been a significant problem with the Cool Customer program.

According to the myPower Link program design, PSE&G was able to call a maximum of 20 curtailment events and a minimum of five events each summer (June – September) of the pilot program. Curtailment events were called on weekdays between the hours of 12 noon and 10 PM, and never on weekends or holidays. In the summer of 2005, a total of 19 curtailment events were initiated from July 11 to September 13 (Table E-1). In the summer of 2006, PSE&G invoked a total of 15 curtailment events from June 19 to September 18 (Table E-2). Curtailments were initiated by PSE&G on the Carrier Comfort Choice website by programming an event prior to or on the day of an event. The Carrier Comfort Choice system then sent a signal to the customer's thermostat to activate the event at the customer location.

Table E-1. myPower Link Summer 2005 Curtailment Days

Date	Start Time	Duration (Hours)	Weather (WTHI)	Price (4 pm LMP*)
July 11	12:00PM	4 hrs	80.2	156
July 18	12:00PM	4 hrs	79.7	244
July 19	12:00PM	4 hrs	82.4	241
July 21	12:00PM	4 hrs	80.0	146
July 22	12:00PM	4 hrs	80.4	150
July 25	12:00PM	2 hrs	80.8	192
July 27	2:00PM	4 hrs	85.6	360
August 02	2:00PM	4 hrs	81.3	210
August 03	2:00PM	4 hrs	81.4	222
August 04	3:00PM	3 hrs	81.1	201
August 10	3:00PM	3 hrs	77.9	173
August 11	4:00PM	2 hrs	81.8	135
August 12	2:00PM	4 hrs	82.3	240
August 15	2:00PM	4 hrs	75.6	99
August 17	2:00PM	4 hrs	75.9	151
August 22	2:00PM	4 hrs	77.2	140
September 01	2:00PM	4 hrs	77.4	126
September 12	2:00PM	4 hrs	77.1	131
September 13	2:00PM	4 hrs	78.2	184

* Locational marginal electric wholesale price ($/MWh) for the PSE&G zone.

Table E-2. myPower Link Summer 2006 Curtailment Days

Date	Start Time	Duration (Hours)	Weather (WTHI)	Price (4 pm LMP*)
Jun 19	2:00PM	4 hrs	79.2	112
Jun 22	3:00PM	2 hrs	80	111
Jul 11	3:00PM	2 hrs	80.9	126
Jul 13	3:30PM	2 hrs	77.1	104
Jul 17	2:00PM	R - 4 hrs	82.9	255
	3:00PM	C - 3 hrs		
Jul 18	2:00PM	R - 4 hrs	84.4	240
	3:00PM	C - 3 hrs		
Jul 26	2:00PM	4	78	107
Jul 27	3:30PM	2	80.7	132
Jul 31	3:00PM	3	81.9	237
Aug 1	2:00PM	R - 4 hrs	85.7	774
		C - 3 hrs		
Aug 2	3:00PM	3 hrs	86.5	464
Aug 7	2:00PM	4 hrs	78.3	135
Aug 15	2:00PM	4 hrs	75.8	89
Aug 22	3:30PM	2 hrs	78(e)	88
Sep 18	2:00PM	4 hrs	74.4	87

* Locational marginal electric wholesale price ($/MWh) for the PSE&G zone.

E.2.1 Technology

Each customer received a Carrier programmable thermostat. The thermostat allowed for the cycling of appliances or temperature setback. The thermostat had an LCD display showing both actual and programmed time and temperature settings, as well as programming information and curtailment status. Buttons allowed for preprogramming daily time period and temperature settings in the heat or cool mode. Additional up and down buttons allowed manual adjustment of temperature settings and also triggered overrides.

The Carrier Comfort Choice Manager (CCM) system remotely controlled customer thermostats and AC equipment, communicated the status of customer equipment, and compiled customer data. The CCM was a secure web-based system allowing remote, pre-set initiation of events as well as real-time monitoring of those events. The system also reported whether a customer overrode a curtailment event.

Twenty-one residential and twenty-three small commercial participants also received an electric interval meter. The customers with interval meters provided additional data that was used to calibrate the thermostat data. Customers who received the electric interval meters were selected utilizing a randomized sampling procedure.

E.2.2 Incentive

Program incentives were directly tied to the number of curtailment events called in the summers of 2005 and 2006, as well as the number of times a customer chose to override the system. The incentive structure was as follows:

- Residential – Participants received a payment of $2.50 per curtailment event; unless they override in which case the payment was forfeited.

- Small Commercial – Participants could receive a maximum annual incentive of $50 at the end of each summer period. Each override of the thermostat during a curtailment event resulted in the customer forfeiting $5 from their $50 incentive. (The total forfeited amount per customer could not exceed the annual $50 incentive.)

E.2.3 Target Market

Residential Pilot participants for myPower Link were selected from PSE&G's general service territory based on the criteria that they have central air conditioning in their homes. Customers were recruited from towns served from transmission nodes that are often constrained in the summer in rank order from the highest Locational Marginal Prices (LMP) to the lowest. Current Cool Customer participants were not targeted. Small Commercial Pilot participants that were on a GLP rate were selected from PSE&G's general service territory.

E.2.4 Marketing, Installation, and Customer Support

PSE&G contracted with Honeywell Utility Solutions (HUS) to handle several myPower Link processes in a turnkey fashion, including equipment installation and customer support. Services HUS provided included:

- Customer Intake Services, including a dedicated toll-free phone number for inbound customer calls and handling of business reply mail leads. The call center was open Monday through Friday, 8 a.m. until 8 p.m., and Saturdays from 8 a.m. until 4 p.m. Customer calls outside of those hours were directed to a live answering service, available 24 hours a day.

- Customer recruitment follow-up calls (telemarketing).

- Pre-Program Surveys to screen potential participants.

- Equipment installation and service calls. Technicians were available 24 hours a day to handle emergencies.

- Customer inquiry and complaint resolution and all customer service support.

PSE&G used direct mail as the primary marketing channel to generate customer participation. Direct mail was supplemented by minimal telemarketing to the small commercial customers to ensure adequate enrollment.

HUS screened customers indicating an interest in the program for eligibility using a scripted questionnaire provided by PSE&G. HUS also conducted brief pre-program surveys over the telephone for eligible customers. The pre-program surveys allowed PSE&G to capture customer attitude and demographic information for program evaluation purposes.

E.2.5 Data Collection and Research

The Pilot was designed to test a variety of topics, including the following.

- **Customer response**. The Pilot measured customer override behavior and included surveys to examine the program's effect on attitudes, knowledge, and behavior.

- **Duration of control.** The Pilot tested control periods lasting 2, 3, and 4 hours to determine customer attitudes regarding event length, relationship between duration and customer override, and to assess the impact on load reduction. The duration was limited to 6 hours but no test of that length was attempted.

- **Frequency of control.** The Pilot was designed to allow more than one curtailment event within the same day. However, only one event per day was attempted during the summer of 2005. In 2006, on six occasions, multiple curtailments were called for pilot testing purposes.

Surveys. Four surveys were implemented as part of the Pilot research:

- **Pre-Program Survey.** 144 surveys were completed via the phone with customers determined to be eligible for program participants. The surveys contained four questions to elicit 1) customer reasons for participating in program, 2) importance of helping the environment by conserving energy, 3) satisfaction with PSE&G, and 4) reasonableness of PSE&G rates.

- **Installation Survey.** Conducted via a mail-back paper survey handed out during the installation. A total of 115 interviews were completed, including 48 with small commercial customers and 67 with residential customers. The surveys rated participant understanding of the program, helpfulness of program material, and satisfaction with the equipment installation.

- **Curtailment Surveys**

  2005. Conducted via phone starting after the 16th curtailment (of 19) was initiated. The survey was conducted through a market research vendor, Schulman, Ronca, & Bucuvalas, Inc. (SRBI). A total of 149 interviews were completed, including 70 with small commercial customers and 79 with residential customers. The surveys asked about awareness of curtailment events and curtailment communication, override behavior, and comfort on curtailment days.

  2006. Interviews were conducted from July 28 through 31, 2006, from SRBI's telephone center. A total of 106 interviews were completed, including 43 with small commercial participants and 63 with residential participants. The overall response rates for small commercial and residential customers were 53% and 70%, respectively.

- **Annual Surveys.** Conducted via telephone in November 2005 and November 2006 through SRBI. In 2005, a total of 125 interviews were completed, including 55 with small commercial and 70 with residential customers. In 2006, a total of 120 interviews were completed, including 60 with small commercial and 60 with residential customers. The surveys contained the same questions as the pre-program survey and were designed to capture changes in customers' understanding of the program, satisfaction, knowledge, attitudes, and informational needs. The survey also asked customers about the operation of the thermostat and demographics.

E.3 Top-Line Results

The research plan was designed to cover four specific elements or assessments:

- Technical Assessment
- Operations Assessment
- Customer Assessment
- Impact Assessment

Top-line results from each of those efforts are summarized below followed by a high-level summary.

E.3.1 Technical Assessment

The Technical Assessment reviewed the design and operation of the technical components of the myPower Link program.

The Carrier thermostats performed well during both summers of operation. In the summer of 2006, no equipment failures were reported.

In 2005, a total of 19 events were initiated from July 11 through September 13, 2005, which did not exceed the planned limit of 20 events. Although event initiation began later in the summer than earlier planned, hotter weather and higher wholesale prices (locational marginal prices) than forecasted enabled the pilot to “catch up” and invoke a sufficient number of events. In the summer of 2006, PSE&G invoked a total of 15 curtailment events from June 19 to September 18. As expected, based on results from other pilot programs, events were characterized by a higher rate of overrides among small commercial customers as compared to residential customers.

The following tables detail the event strategy, customer communication status, and override results for each event for 2005 and 2006.

Table E-3. Summary of myPower Events – 2005

SUMMARY OF MYPOWER LINK EVENTS - 2005																
			PRE NOTIFY	THERMO SETBACK	DUTY CYCLE(ON)	WEATHER(WTHI)		PRICE (4PM LMP)		START TIME	DURATION	DEVICES			OVERRIDES	
EVENT	DATE	CLASS				Forecast	Actual	Forecast	Actual			Available**	Confirmed	%	Number	% of Confirm.
1	11-Jul	Res			30	81.5	80.2	150	156	12:00PM	4 hrs	111	94	85%	5	5%
		Comm'l		4								133	93	70%	41	44%
2	18-Jul	Res			30	80.3	79.7	150	244	12:00PM	4 hrs	112	111	99%	14	13%
		Comm'l		4								144	140	97%	65	46%
3	19-Jul	Res			30	81.6	82.4	190	241	12:00PM	4 hrs	112	110	98%	15	14%
		Comm'l		4								144	134	93%	47	35%
4	21-Jul	Res			45	81.6	80	175	146	12:00PM	4 hrs	112	109	97%	8	7%
		Comm'l		2								144	138	96%	25	18%
5	22-Jul	Res			45	81.6	80.4	168	150	12:00PM	4 hrs	112	107	96%	14	13%
		Comm'l		2								144	139	97%	33	24%
6	25-Jul	Res			45	81.7	80.8	162	192	12:00PM	2 hrs	112	106	95%	4	4%
		Comm'l		2								144	137	95%	27	20%
7	27-Jul	Res			30	84.6	85.6	201	360	2:00PM	4 hrs	112	109	97%	15	14%
		Comm'l		4								144	139	97%	43	31%
8	2-Aug	Res	yes		30	80.9	81.3	170	210	2:00PM	4 hrs	112	108	96%	14	13%
		Comm'l		4								148	142	96%	39	27%
9	3-Aug	Res	yes		30	83.1	81.4	196	222	2:00PM	4 hrs	112	109	97%	19	17%
		Comm'l		4								148	141	95%	52	37%
10	4-Aug	Res	yes		30	83.1	81.1	266	201	3:00PM	3 hrs	112	109	97%	13	12%
		Comm'l		4								148	140	95%	36	26%
11	10-Aug	Res	yes		20	78.3	77.9	128	173	3:00PM	3 hrs	111	111	100%	10	9%
		Comm'l		4								147	145	99%	36	25%
12	11-Aug	Res	yes		20	81.8	81.8	161	135	4:00PM	2 hrs	110	110	100%	10	9%
		Comm'l		4								148	145	98%	26	18%
13	12-Aug	Res	yes		30	81.8	82.3	165	240	2:00PM	4 hrs	110	110	100%	16	15%
		Comm'l		4								148	145	98%	41	28%
14	15-Aug	Res	yes		15	78.9	75.6	170	99	2:00PM	4 hrs	110	106	96%	5	5%
		Comm'l		2								148	143	97%	24	17%
15	17-Aug	Res	yes		15	76.7	75.9	135	151	2:00PM	4 hrs	110	109	99%	16	15%
		Comm'l		2								148	142	96%	23	16%
16	22-Aug	Res	yes		15	79.2	77.2	119	140	2:00PM	4 hrs	111	109	98%	14	13%
		Comm'l		2								147	145	99%	22	15%
17	1-Sep	Res	yes		15	78.3	77.4	210	126	2:00PM	4 hrs	111	108	97%	3	3%
		Comm'l		2								151	147	97%	21	14%
18	12-Sep	Res	yes		30	78.3	77.1	154	131	2:00PM	4 hrs	111	109	98%	12	11%
		Comm'l		4								150	150	100%	44	29%
19	13-Sep	Res	yes		30	78.9	78.2	147	184	2:00PM	4 hrs	111	108	97%	12	11%
		Comm'l		4								151	149	99%	37	25%

Note: The “Summary of myPower Events” table shows a count of 151 available small commercial thermostats and 111 residential. Those numbers include three ‘test” thermostats used in the program to monitor curtailment events and system functionality. Two of the test thermostats installed (one at PSE&G and one at Honeywell), are registered under the small commercial customer group. The third test thermostat utilized by Carrier is registered under the residential customer group.

Table E-4. Summary of myPower Events – 2006

		SUMMARY OF MYPOWER LINK EVENTS - 2006															
			PRE NOTIFY	THERMO SETBACK	DUTY CYCLE(ON)	WEATHER(WTHI)		PRICE (4PM LMP)		START TIME	DURATION	DEVICES			OVERRIDES		NOTES
EVENT	DATE	CLASS				Forecast	Actual	Forecast	Actual			Available**	Confirmed	%	Number	% of Confirm.	
1	19-Jun	Res	yes		30	79.1	79.2	122	112	2:00PM	4 hrs	105	103	98%	16	16%	(1)
		Comm'l		4								140	139	99%	34	24%	(1)
2	22-Jun	Res	yes		30	80	80	117	111	3:00PM	2 hrs	107	106	99%	7	7%	(1)
		Comm'l		4								141	135	96%	19	14%	(1)
3	11-Jul	Res	yes		30	78.2	80.9	97	126	3:00PM	2 hrs	108	105	97%	5	5%	
		Comm'l		4								138	135	98%	26	19%	
4	13-Jul	Res	yes		30	80.3	77.1	117	104	3:30PM	2 hrs	107	103	96%	5	5%	
		Comm'l		4								141	138	98%	20	14%	
5	17-Jul	Res	yes		15-40	83.6	82.9	177	255	2:00PM	4 hrs	106	103	97%	15	15%	(2), (3)
		Comm'l		3 to 5						3:00PM	3 hrs	141	138	98%	31	22%	(2), (3)
6	18-Jul	Res	yes		20-40	85.4	84.4	254	240	2:00PM	4 hrs	106	73	69%	5	7%	(2), (4)
		Comm'l		3 to 5						3:00PM	3 hrs	141	98	70%	14	14%	(2), (4)
7	26-Jul	Res	yes		15	78.1	78	119.3	107	2:00PM	4 hrs	105	105	100%	14	13%	
		Comm'l		6								141	133	94%	44	33%	
8	27-Jul	Res	yes		15	79.1	80.7	124.1	132	3:30PM	2 hrs	105	105	100%	8	8%	
		Comm'l		6								141	134	95%	28	21%	
9	31-Jul	Res	yes		30	81	81.9	190	237	3:00PM	3 hrs	108	105	97%	6	6%	(2), (5)
		Comm'l		4								139	131	94%	23	18%	(2), (5)
10	1-Aug	Res	yes		15-45	84.5	85.7	290	774	2:00PM	4 hrs	106	62	58%	3	5%	(2), (6)
		Comm'l		2 to 6						2:00PM	3 hrs	139	89	64%	9	10%	(2), (7)
11	2-Aug	Res	yes		30	87.4	86.5	354	464	3:00PM	3 hrs	106	106	100%	13	12%	(5)
		Comm'l		4								137	135	99%	25	19%	(5)
12	7-Aug	Res	yes		45	79.1	78.3	138	135	2:00PM	4 hrs	106	102	96%	8	8%	
		Comm'l		2								137	134	98%	17	13%	
13	15-Aug	Res	yes		30	79.1	75.8	111	89	2:00PM	4 hrs	106	101	95%	10	10%	
		Comm'l		4								135	131	97%	35	27%	
14	22-Aug	Res	yes		15	78.2	78(e)	99.5	88	3:30PM	2 hrs	105	104	99%	6	6%	(5)
		Comm'l		6								135	131	97%	18	14%	(5)
15	18-Sep	Res	yes		30	76.3	74.4	65	87	2:00PM	4 hrs	103	100	97%	6	6%	
		Comm'l		4								128	128	100%	37	29%	

NOTES

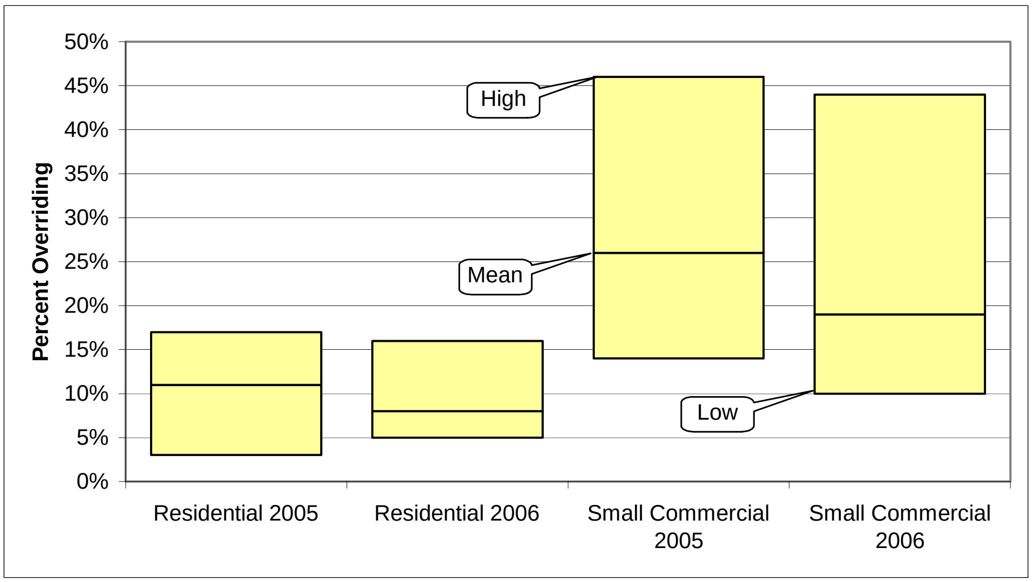
(1) manual phone calls and emails only while DAVOX system out for maintenance.
(2) number of confirmed and overrides not final pending review of run time data
(3) cycling/setback changed each hour
(4) cycling/setback changed each hour except 4pm
(5) single refresh at 4:30
(6) one event from 2-4 with change at 3, second from 4-6 with 5pm refresh
(7) one event from 2-4 with change at 3, second from 4-5

Note: Event Criteria
Forecast WTHI = 77
Day ahead 4pm LMP = 115

**includes two test devices

It seems intuitive that longer duration control events, hotter weather, and longer duty cycles would be associated with more frequent override behavior. While the data in 2005 provided some support to that hypothesis, the evidence was not strong. In 2006, several more targeted event strategies were employed to reduce the override rate and increase the kW impact on peak loads. The objective was to synchronize the "high impact" strategy such as 15 minutes (on) residential duty cycle with the time of system peak or high LMP while reducing the "discomfort" level during other times, lessening the propensity to override the event. **These strategies seemed to work as there were fewer overrides in 2006.** On average, 11% of residential participants overrode control events in 2005 and 8% in 2006. The rate on individual control days varied from 3% to 17% in 2005 and between 5% and 16% in 2006. On average, 26% of small commercial participants overrode control events in 2005 and 19% in 2006. Their rate on individual control days varied from 14% to 46% in 2005 and 10% to 44% in 2006.

Figure E-1. High, Low, and Average Percent of Participants Overriding Control



One of the technical issues that arose involved the Carrier Comfort Choice Manager (CCM)/Customer communication rate, which indicated potentially non-communicating devices. Although the initial communication rate of 95% in summer 2005 was consistent with industry experience at 95%, PSE&G challenged Carrier to further improve upon this result. By sending multiple broadcast signals followed by individual messages to the non-confirming units, Carrier was able to increase the communication rate to an average of 98%, and even reached 100% during certain events.

Another issue was the ability to control the cycling strategy. The software in the CCM did allow pre-programming on/off cycles. These could be in 5 minute increments out of an hour (e.g., 5 minutes on, 55 minutes off, 10 minutes on, 50 minutes off, etc.) to achieve any "percentage" duty cycle. However, the control period was always measured within an hour, rather than a more tightly defined time frame. For example, CCM could not implement a cycling strategy to achieve a 50% duty cycle by specifying that the equipment should operate 10 minutes on and then 10 minutes off. At the time of the pilot, the system could only implement a 50% cycling strategy by cycling 30 minutes on and then 30 minutes off. Similarly, a 75% cycling strategy could only be implemented as 15 minutes on and 45 minutes off. This was an equipment design constraint, not a program constraint and Carrier was considering an update to the duty-cycle algorithms in their software to allow more cycling strategy choices for future users of their technology. This was not available for the myPower Link pilot program.

E.3.2 Operational Assessment

The Operational Assessment reviewed the internal procedures for marketing and operating the myPower Link program.

Marketing. Most of the participants were recruited through direct mail. The response to the direct mail campaign was above the typical 1-2% average for the residential segment. With a 3.2% response rate, 334 residential customers responded to the campaign. Of the 334 respondents, 59% (197) responded with the Business Reply Card and 41% (137) called on the phone. No telemarketing was required to boost the response from residential customers. The small commercial response rate was less than the residential at 1%. Of the 65 small commercial respondents, 54% (35) responded with the Business Reply Card and 46% (30) called in. The small commercial leads needed to be supplemented with outbound telemarketing to recruit additional participants due to the small list of potential participants. An additional 121 leads were obtained through the telemarketing.

Signups. Approximately 15% of the residential customers who initially expressed an interest in participating in the program changed their minds about participating when called back to undergo the screening survey (see Table E-5 and Figure E-2). Just over 17% of the small commercial customers changed their minds. Just over 17% of residential customers and 28.5% of small commercial customers were screened out over the phone or during the installer's on-site visit.

Table E-5. Disposition of Leads

	Residential	% of Total	Small Commercial	% of Total
Total Leads	334	100.0%	186	100.0%
Customer not interested/changed mind	51	15.3%	32	17.2%
Customer not eligible for program	32	9.6%	24	12.9%
Screened out on-site for technical reasons	25	7.5%	29	15.6%
# of program drop-outs	5	1.5%	5	2.7%
# of customer in hold status †	123	36.8%	3	1.6%
# of installations end of summer 2005	98	29.3%	93	50.0%

† Interested in being a participant but not enrolled in the program because the program quotas were met.

Figure E-2. Disposition of Leads

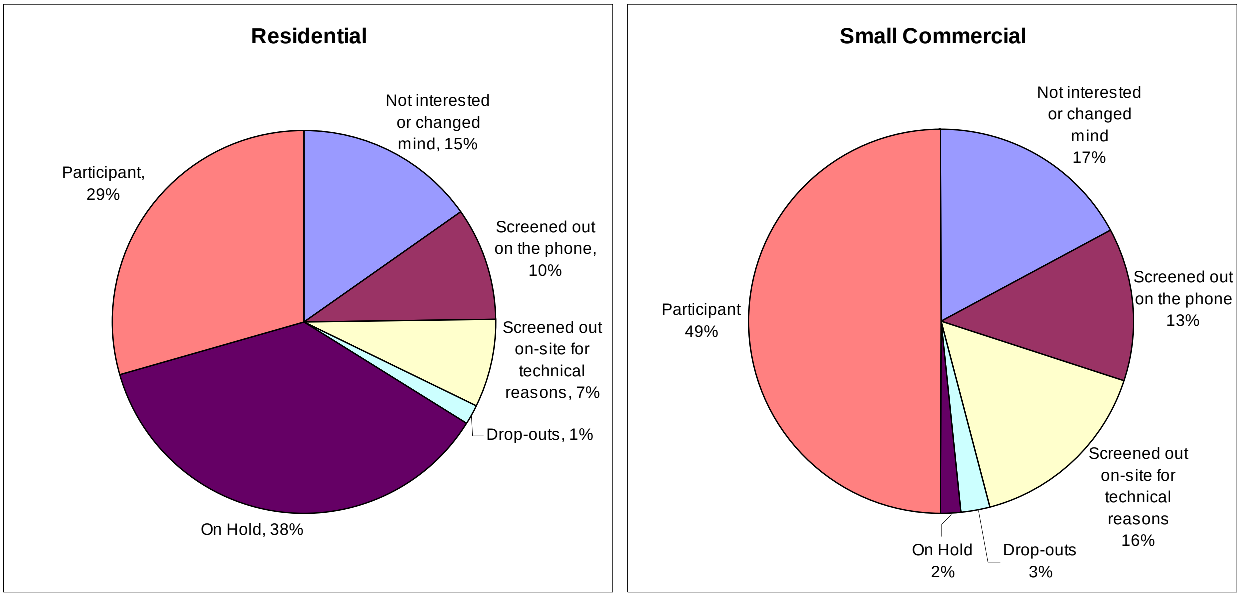


Table E-6. Reasons Interested Customers were Screened Out on the Telephone

Reason for Elimination	**Residential**	**% of Total**	**Small Commercial**	**% of Total**
Customer changed mind	34	41.0%	20	35.7%
Customer not interested in program	17	20.5%	12	21.4%
Damper systems	10	12.0%	7	12.5%
Summer/winter switch	7	8.4%	1	1.8%
No central AC	6	7.2%		0.0%
Attic not floored	3	3.6%		0.0%
Moved/moving	3	3.6%	5	8.9%
Friend/family of PSE&G	2	2.4%		0.0%
AC not working	1	1.2%	2	3.6%
Needed back plate		0.0%	1	1.8%
More than 5 thermostats		0.0%	6	10.7%
Renter		0.0%	1	1.8%
Unable to contact		0.0%	1	1.8%
Total Eliminations	**83**	**100.0%**	**56**	**100.0%**

Table E-7. Reasons Interested Customers Were Screened Out On-Site

Reason for Elimination	Residential	% of Total	Small Commercial	% of Total
F1 – no signal available	13	52.0%	3	10.3%
No access	7	28.0%	3	10.3%
Can't detect wire	4	16.0%	12	41.4%
On site customer cancellation	1	4.0%	0	0.0%
Damper system (Trane)	0	0.0%	6	20.7%
Mounting not possible	0	0.0%	1	3.4%
AC unit not working	0	0.0%	4	13.8%
Total	**25**	**100.0%**	**29**	**100.0%**

Curtailment Events. Once it was determined that an event would be initiated, a process was utilized to notify all applicable parties prior to an event, so that they could respond to any customer inquires that might occur. Applicable parties included HUS, the PSE&G Call Center, the myPower Team, the myPower Steering Committee, the PSE&G Demand Side Management (DSM) Department, the NJ Board of Public Utilities, and the NJ Division of Rate Counsel (formerly the NJ Division of the Ratepayer Advocate). In 2006, the information was also posted on the PSE&G website. A formal stakeholder Curtailment Notification process was established and utilized.

In 2005, after PSE&G initiated the first two curtailment events, it was decided to implement a customer notification system in an attempt to reduce customer overrides. The system was designed to use an automatic call program with pre-defined scripts for the small commercial and residential participants. The call system failed to operate successfully in 2005, however it was successfully modified for use in the 2006 season.

E.3.3 Customer Assessment

The Customer Assessment reviewed the results of participant research implemented for the myPower Link program. The customer assessment was designed to evaluate the overall effectiveness of the pilot program by measuring changes in participant attitudes and behaviors.

Satisfaction with PSE&G

Participants were asked about their satisfaction with PSE&G in the Pre-Program Survey and after the first season in the Annual Survey.

The myPower Link program participation positively impacted participants' reported willingness to conserve electricity usage in the future and participants' views on the reasonableness of PSE&G's rates. However, satisfaction with PSE&G was higher among participants before the program began than after, (8.7 before the program on a 10-point scale where 10 is "extremely satisfied" vs. 8.3 after the summer of 2006). It seems that program participation may have negatively affected participants' perceptions of PSE&G. Since the survey methodology necessitated that the Pre-Program survey be no more than 5 questions, there is not enough detail from the Pre-Program survey to precisely determine the reason for the decline in overall satisfaction with PSE&G from the myPower Link program start to finish. Ratings and customer comments measured through the Curtailment and Annual Surveys do seem to indicate that a cause of the decline was dissatisfaction with the quality of the communications surrounding the curtailment events. Small commercial participant satisfaction was also impacted negatively by the number of events, the comfort level during the events, and the amount of the program incentive. Residential participants averaged 8.3 and small commercial participants averaged 8.0 after the summer 2006 program season. Satisfaction with PSE&G did not change substantially between the end of the 2005 control season and the end of the 2006 season.

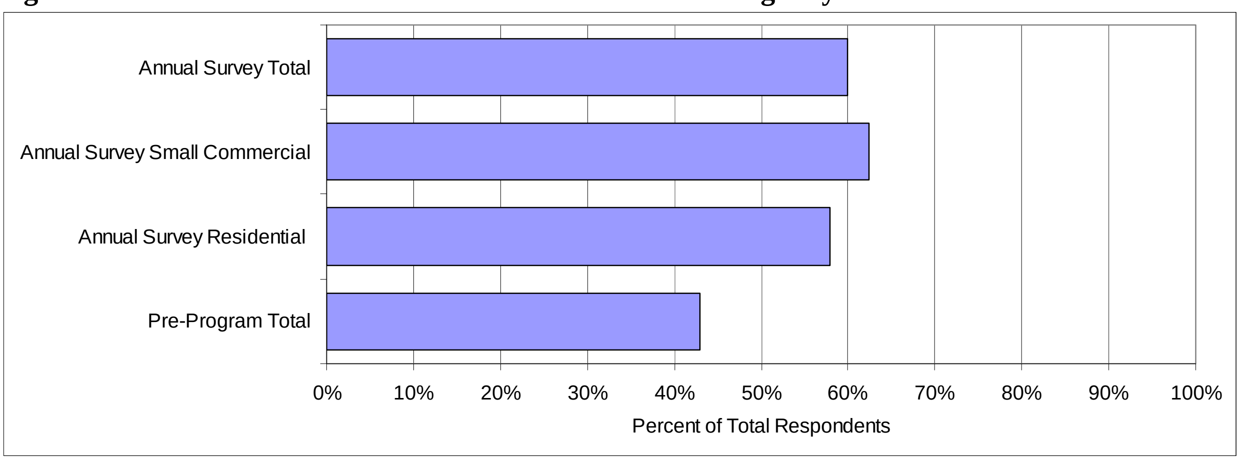
Table E-8. Satisfaction with PSE&G (1-10 scale where 10 is "very satisfied")

When Surveyed	*All Respondents*	*Residential*	*Small Commercial*
Before the Program	8.7	8.8	8.6
After 2005 Program	8.2	8.4	8.0
After 2006 Program	8.3	8.3	8.0

Satisfaction with PSE&G Rates

Participants were asked about the reasonableness of PSE&G rates in the Pre-Program Survey and after the first season in the Annual Survey. Before the program, just under half of myPower Link program participants felt that PSE&G's rates were reasonable (43%) and 22% felt that they were unreasonable. After the summer of 2005, participants' ratings of the reasonableness of PSE&G's rates had increased significantly to 60%, dissatisfaction had declined to 20% (see Figure E-8).

Figure E-3. Reasonableness of PSE&G Rates – Percent feeling they are reasonable – 2005



Pre-Program Survey

As one might expect, customers' main motivations for participating in the myPower Link program were financial or incentive based. Almost three quarters (70%) said they participated to "reduce their energy bill" (multiple answers were accepted). Just under half (49%) said that conserving energy was a main motivator in their decision to participate. Just under half (48%) also participated for the free thermostat. One third (33%) participated for the incentive payment.

While their motivation to join the program was more likely due to the monetary benefits of participation, most customers participating in the program felt that it is very (68%) or somewhat (27%) important to have the ability to conserve energy to help the environment.

Installation Survey

Residential and small commercial participants were highly satisfied with their installation experience. On a 1-10 scale where 1 is "Completely Dissatisfied" and 10 is "Completely Satisfied" both residential and small commercial participants gave an average answer of 9.2.

Both residential and small commercial participants reported that their knowledge of the myPower Link program increased from the time they signed up to after the thermostat installation, averaging a 1.5 point increase from 7.0 to 8.5 on a 1-10 scale where 10 is "Understood it completely."

Most participants thought the Q&A brochure, thermostat manual, and thermostat operation guide were helpful (with average scores of 8.3-8.5). Participants generally felt that the static window sticker was not as helpful with an average score of 7.2.

With ratings that ranged from the high 8s to the high 9s (on a 1-10 point scale), both residential and small commercial participants were highly satisfied with all aspects of the service provided by the person who installed the thermostat.

Curtailment Survey

The curtailment survey was implemented July 28 through July 31, 2006 with 106 participants, including 43 small commercial participants and 63 residential participants. Awareness of specific curtailment events has improved—the majority of participants (68%) said they were aware of the July 27, 2006 curtailment compared to just 29 percent that were aware of the August 2005 curtailment. Recollection of the automated call rose substantially (57% said they received the automated call in 2006 vs. 12% in 2005).

Personal calls had a greater impact on customers' decisions to override the curtailment—35% said that the automated call had a great deal or some impact on their decision whether to override the curtailment compared to 59% who said the personal call they received had a great deal or some impact on their decision.

Respondents who did not mention receiving a personal call were asked specifically whether they had received such a call. Just under one-quarter (21%) of participants said they received a personal call from PSE&G regarding the curtailment. The majority of participants (59%) said that the personal call had some or a great deal of impact on their decision whether or not to override the event.

The majority of participants said the curtailment communications they received were either better than (25%) or the same as last year (41%). Residential participants were more likely than the small commercial participants to say that program communications were about the same as last year (51% vs. 28%).

The majority of participants were comfortable, even though the July 27, 2006 curtailment event was more severe (residential customers' air conditioners were cycled off for longer periods of time than in 2005 and small commercial customers' thermostats were raised six degrees compared to four degrees last year). Small commercial customers expressed more discomfort than residential customers.

All of the participants who were aware that the curtailment was over-ridden said they overrode the curtailment because the temperature of their home or business became too uncomfortable.

Annual Survey

The myPower Link Annual Surveys were conducted via telephone in November 2005 and November 2006. In 2005, a total of 125 interviews were completed, including 55 with small commercial customers and 70 with residential customers. In 2006, a total of 120 interviews were completed, including 60 with small commercial customers and 60 with residential customers. The survey covered satisfaction with PSE&G and satisfaction with the program and its components, understanding of the program, and override behavior, among other things.

Impact of Program on Satisfaction with PSE&G. Participation in the program had a relatively low impact on participant's satisfaction with PSE&G overall in 2006—no significant changes were measured with respect to satisfaction with PSE&G from 2005 to 2006. Satisfaction among 2006 myPower Link participants is about the same as that measured for PSE&G customers overall (Customer Relationship Survey Q3 2006 YTD results: Residential customers—8.0 and Small Commercial customers—7.8).

Satisfaction with Program. On average both residential and small commercial participants were satisfied with the myPower Link Program in both 2005 and 2006. On a scale from 1 to 10 where 10 is "extremely satisfied", residential participants had an average score of 8.1 in 2005 and 8.5 in 2006. Small commercial participants had an average score of 7.4 in 2005 and 6.9 in 2006. One possible reason for the difference in scores is that the curtailment events occurred when residential participants were much less likely than small commercial participants to be in residence; thus, the curtailment events were more likely to have an impact on the comfort levels of small commercial than residential customers. Dissatisfied respondents say their primary concern is that their home or office was too hot during curtailment events.

While large differences in satisfaction were measured between residential and small commercial customers, their commitment to and willingness to recommend the myPower Link program was virtually equal: 94% of residential participants in 2005 and 93% in 2006 would recommend the myPower Link to a friend.

Number of Events. PSE&G called 19 events in 2005 and 15 in 2006. On average, residential participants said they experienced 13.7 events and small commercial participants thought they had 8.9 events. Overall, 35 percent of respondents said they experienced between six and ten curtailment events during the summer of 2006. Twenty-three percent said they experienced 11 to 15 events and 13 percent said 16 or more events. In contrast, 13 percent of participants said they experienced only 1 to 5 events.

More residential participants stated they did not know how many control events there were in 2006 than in 2005 (18% vs. 9%). On the other hand, fewer small commercial participants said they did not know (8% vs. 27%).

Overrides. Overall, 43 percent of respondents said they overrode at least one curtailment event in 2006, compared with 45 percent in 2005. Thirty-five percent of residential participants said they overrode one or more events, compared with 40 percent in 2005. Fifty percent of business participants said they overrode one or more events, compared with 51 percent in 2005.

Many participants believe better communication would help reduce the number of overrides. When asked what PSE&G could do to keep them from overriding events in the future, the most common answers related to communication – calling before the event and giving more warning before the event (Table E-9).

Table E-9. What PSE&G Could Do to Keep Customers from Overriding Future Events

What, if anything, could PSE&G have done to have kept your home/office from over-riding future events?	2005 (%)	2006 (%)
Don't increase the temperature during the curtailment event as much	9	29
Call me to let me know that the event will be taking place	30	20
Give me more time between notification and event	27	14
Have fewer events during the summer	2	14
Provide a lock box	7	10
Don't set the temperature back on my air-conditioner during the curtailment event - let it cycle on and off instead	13	8
Provide advice on how to maintain comfort during an event	11	6
Flexibility of events to accommodate customer usage	0	6
Clearer notification on thermostat regarding an event	5	4
Thermostat alert/warning: about to override	2	4
PSE&G control of thermostat	0	4
Other	14	2
Better explanation of the program	9	2
Reduce the amount of time my air conditioner is off	4	0
Shorter events	2	0
Increase the incentive	2	0

More than one answer allowed so percentages total more than 100%.

E.3.4 Impact Assessment

This section presents the results of the impact evaluation of the 2006 myPower Link Utility Activated Load Management Pilot program. This analysis used statistical modeling approaches that related metered electricity usage to weather conditions and the curtailment event. Three analyses are conducted:

- Assessment of the load impacts of residential sector curtailment events using a constant cycling strategy.
- Assessment of the load impacts of small commercial curtailment events using a constant temperature setback control strategy.
- Assessment of flexible control strategies for both residential cycling strategies and the temperature setback control strategy in the small commercial sector where the strategies varied across the hours of the curtailment event.

The model used in this impact evaluation of myPower Link indicates that the program produces substantive and measurable effects on AC load during curtailment periods. The model calculated average impacts across all customers, including those who overrode curtailment events. As a result, the impacts include the effect of any customer overrides that might lower the impacts. For the residential sector, the program results in a 1.12 kWh impact with a 75% cycling strategy at an outside temperature of 90°. For small commercial customers, the impacts were significantly larger (1.6 kWh with a 2° setback at 90° during the first hour). However, the small commercial impacts declined significantly during the period of the setback event. The results by outside temperature and cycling/setback rates are presented in Table E-10 (residential) and E-11 (small commercial).

Table E-10. Estimated Impacts (average kW per hour) at different cycling and temperature conditions – RESIDENTIAL

Cycling (% off) held constant over the event period	Outside Temperature		
	<90°	90°	95°
25%	0.27	0.37	0.44
50%	0.54	0.75	0.89
75%	0.80	1.12	1.33

Table E-11. Estimated Impacts (average kW per hour) at different setback and temperature conditions – SMALL COMMERCIAL

Initial Therm. Setback with no change during the event[2]	Outside Temperature		
	<90°	90°	95°
2° or 4°[3]			
First hour	1.57	1.96	2.16
Second hour	1.77	2.16	2.36
Third hour	1.07	1.46	1.66
Fourth hour	0.31	0.70	0.90
6°			
First hour	2.12	2.51	2.71
Second hour	2.32	2.71	2.91
Third hour	1.62	1.01	2.21
Fourth hour	0.86	1.25	1.45

The key findings from the analyses above are that a constant cycling strategy throughout the event can achieve a kW reduction of 1.33 on a peak day (i.e., outdoor temperature over 95°. For the temperature set back, a peak reduction of 2.91 kW was attained on peak weather days. These are the capacity values associated with this program given constant cycling and a single thermostat set back during the event period.

The analysis presented above focused primarily on the impacts associated with a curtailment event taken as a whole. Flexible control strategies were also examined in this analysis. This is a relatively new development in mass-market control programs where the control strategy varies across the hours of the event period. Developments in load curtailment technologies (both switches and thermostats) now allow for the cycling strategy to change across the hours of a curtailment event and for the temperature setback to vary across hours of the event. This provides an opportunity to test whether different curtailment

---

[2] One of the reasons that the second hour impacts are larger than the first hour may be the staggered start of the curtailment. Not all participants were setback at the same time.

[3] There is no statistically significant difference between the two setbacks according to the regression results. This is likely due to the small number of 2° setback events.

strategies that take advantage of this flexibility can produce greater kW impacts during the hour of the expected peak demand, or stabilize the kW impacts over the curtailment period.

In 2006, PSE&G made a concerted effort to fine-tune several events by altering the cycling and setback points as well as refreshing thermostats within a given curtailment event. Several important findings resulted from the analysis of these flexible control strategies. These are shown below:

- For a temperature setback program, these strategies can be used to keep the load impacts during a curtailment period relatively constant if the setback temperature is increased in each subsequent hour. This is demonstrated in the results for the August 1 event where the impacts ranged from 2.01 for the first hour to 2.58 for the third hour. This contrasts dramatically with a constant temperature setback of 6 degrees in the first hour which results in a degradation of impacts in subsequent hours, i.e., from 2.36 to 0.90 across three hours (see Table E-11).

- The largest one hour impact comes from a temperature set back of 6^{o} at the beginning of a curtailment event. For peak day events, a reduction of 2.9 kW is attained in the initial hours of the event prior to the degradation of the impacts. As a result, if the hour in which the system peak demand is to occur can be forecast very accurately, the maximum system peak reduction can be attained by a thermostat temperature setback in that hour.

- Varying the cycling strategy within an event can increase the on-peak impacts for a cycling program. For example, one such strategy would be to use a 33% cycling strategy in the first hour, 50% in the second hour, and 75% in the third hour. The impacts of such a strategy are shown for the August 1 control event where the impacts from a constant control strategy are estimated to produce a 1.33 kW reduction, while the flexible control strategy outlined above produced a 1.7 kW impact in the final hour of the event.

- Having a “refresh call” that reduces the number of overrides for the small commercial sector during 4° setback events results in a significant increase in the load impacts, i.e., an average increase of 0.80 kW.

- For the residential sector, having a refresh call during an 50% cycling event will add a 0.22 kWh load reduction during an event, on average, and 0.35 kWh for a 75% cycling event.

Overall, flexible control strategies can be used to achieve both higher impacts in specific hours and more stable impacts across hours. These strategies can be used to achieve strategic objectives by attaining higher load impacts during a specific hour (or across two hours) if the forecast of system peak can be matched to those time frames.

E.3.5 Summary

The myPower Link pilot demonstrated the benefits of implementing a small-scale program before starting a full-scale rollout. The myPower Link pilot demonstrated the benefits and drawbacks of the particular approach and technology chosen to support making an informed decision about expanding the pilot into a full-scale program. The relevant issues and preliminary findings are as follows:

- Customer response to the marketing campaign was high, particularly from residential customers, indicating a significant interest in the program’s approach.

- Participants were quite satisfied with the program, indicating that drop-out rates should not be higher than expected. This was validated when relatively few customers dropped out after either the first or second summer control season.

- The myPower Link technology enabled participants to override control events. This placed more power in the participants' hands than the Cool Customer program provides, which should broaden the base of customers willing to consider signing up and reduce drop-out rates.

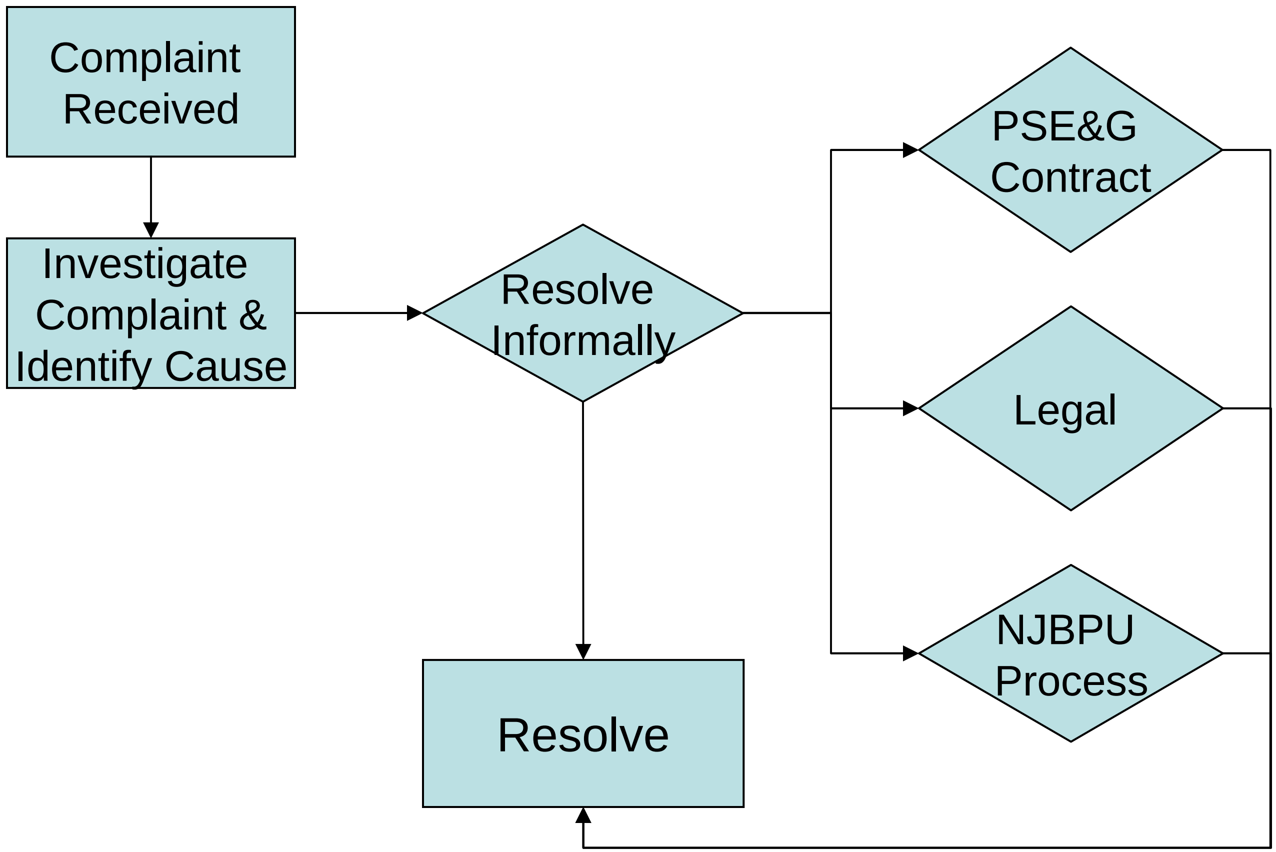
- In the first season, on average 11% of residential and 26% of small commercial participants overrode control events. Even with this level of override behavior, the total load impacts from the program were within the expected range. For the residential sector, the program produced a 1.0 kWh impact with a 75% cycling at an outside temperature of 90°. For small commercial customers, the impacts were 2.0 kWh with a 2° setback at 90° during the first hour. For the second season of the program, residential overrides ranged between 5% - 16%, with an average of 8%. Small commercial overrides ranged from 10% to 44%, with an average of 19%. In 2006, several more targeted event strategies were employed to reduce the override rate and increase the kW impact on peak loads. The objective was to synchronize the "high impact" strategy such as 15 minutes (on) residential duty cycle with the time of system peak or high LMP while reducing the "discomfort" level during other times, lessening the propensity to override the event. These strategies seemed to work as there were fewer overrides in 2006.

- In 2006, the total load impacts from the program were again within the expected range. For the residential sector, the program produced a 1.33 kWh impact with 75% cycling at an outside temperature of 95°. For small commercial customers, the impacts were 2.71 kWh with a 6° setback at 95° during the first hour and 2.91 during the second hour.

- The technology used in the myPower Link pilot used two-way communication so that the thermostats would verify that they received PSE&G's control signal and implemented the control strategy. As a result, in real time the myPower Link program could provide reliable estimates of load reduction. In contrast, the Cool Customer program uses one-way communication technology and as a result its impacts are much less certain.

Schedule FAL-4

COMPLAINT PROCESS FLOW CHART



ATTACHMENT B

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
DIRECT TESTIMONY
OF
STEPHEN SWETZ
MANAGER – RATES AND REGULATION

My name is Stephen Swetz and I am the Manager – Rates and Regulation for Public Service Electric and Gas Company (PSE&G, the Company). My credentials are set forth in the attached Schedule SS–1.

SCOPE OF TESTIMONY

The purpose of my testimony is to support the Company's proposed methodology for recovery of the costs related to PSE&G's Demand Response Program (Program), including projected rate and bill impacts. My testimony provides details of the proposed calculations and recovery mechanisms.

COST RECOVERY MECHANISM

General

PSE&G is proposing to recover the revenue requirements associated with the Incremental Direct Costs of the Program. Incremental Direct Costs include the incremental Program Investments, incremental Capitalized IT Costs and the incremental Administrative Costs of running the Program, including incremental labor and other incremental costs. Since the Residential A/C Cycling Sub-Program is proposed to replace the legacy Residential A/C Cycling Program, it is proposed that the current System Control Charge (SCC) - which collects the revenue requirements for the current Residential A/C cycling program be eliminated and the corresponding revenue requirements be included in the proposed Program. As the new Residential A/C Cycling Sub-Program replaces the legacy program, the revenue requirements associated with the legacy Residential A/C Cycling Program will decrease during the new Program's implementation and will be eliminated when all of the legacy switches and T-Stats are replaced. PSE&G is proposing that the Board authorize the recovery of the revenue requirements of the Program in accordance with the Regional Greenhouse Gas Initiative (RGGI) legislation, *N.J.S.A.* 48:3-98.1 et seq. The details of the costs proposed to be recovered, as well as the mechanism for such recovery, are described in the following sections of this testimony.

Calculation of the Revenue Requirements of Direct Costs

The Program investments are proposed to be treated either as separate classes of utility plant or as regulatory assets, depending on the type of investment, and depreciated or amortized as described in the corresponding section below. The revenue requirements associated with the Direct Costs of the Program would be expressed as:

*Revenue Requirements = (Cost of Capital * Net Investment) +Amortization or Depreciation – Demand Response(DR) Revenues Credited to Customers + Customer Incentives + Administrative Costs*

The details of each of the above terms are described as follows:

Cost of Capital – This is PSE&G's overall weighted average cost of capital (WACC) authorized by the Board in the most recent base rate case, including income tax effects plus an incentive of a portion of the DR Revenue, capped at 100 basis points on the Cost of Common Equity. The calculation deriving this current value, which is equal to 12.1138% per year or 1.0095% per month, is shown in Schedule SS-2

Net Investment – This is the net balance of:

1. The assets equal to the Program investments less their associated accumulated depreciation and / or amortization.
2. Capitalized IT costs less its associated accumulated amortization.
3. Accumulated Deferred Income Tax (ADIT)

Depreciation/Amortization – The Depreciation or Amortization of the Program is composed of two components:

1. The depreciation or amortization of each of the Program investments will vary depending on the type of investment. The table below summarizes the

book recovery and associated tax depreciation applied to the individual sub-program investments.

Sub-Programs	Book Recovery	Tax Depreciation
Residential A/C Cycling	15 year dep.	15 year MACRS
Residential Pool Pump Load Control		
Small Commercial A/C Cycling		
Commercial & Industrial (C&I) Curtailment Services	10 year amort.	Expensed
Load Shifting Demonstration–Flow Battery	20 year dep.	15 year MACRS
Load Shifting Demonstration–Cool Storage		
Load Shifting Demonstration–Solar Streetlights		
Load Shifting Demonstration–Plug-in Hybrid Electric Vehicle (PHEV)	Expensed	Expensed

The amortization/depreciation would be based on a monthly vintaging methodology instead of the mass property accounting typically used for utility property.

2. The amortization of the Capitalized IT costs. It is anticipated that a Demand Response Program management system for these sub-programs will be needed. Costs associated with the management system will be accounted for in accordance with PSE&G's existing capitalization policy. It is currently estimated that this management system will cost approximately $1 million and be amortized over five years.

DR Revenues Credited to Customers – This is net amount of ILR Revenue, DR Energy Payments or other DR related revenues that the Company receives through the operation of the Program and shares with customers. This amount will reduce revenue requirements.

<u>Customer Incentives</u> – This is the amount paid to Program participants as compensation for allowing PSE&G to control their electric load in accordance with the Program rules.

<u>Administrative Costs</u> – Administrative Costs would include any incremental PSE&G labor and other related on-going costs required to run the Program. For modeling purposes, the recovery of the Load Shifting Demonstration – PHEV costs are included here.

The monthly detailed calculation of the Revenue Requirements for each of the five sub-programs are shown for the first two years, along with an annual summary for ten years (see Schedules SS–3a through SS–3e). The cumulative summary of these revenue requirements of the Program along with the revenue requirements associated with the Legacy Residential A/C Cycling Program are shown in Schedule SS-3. The SCC's projected December 31, 2008 deferred balance along with the associated interest payable, estimated to be $3,831,000 over-recovered, will reduce the initial period's Revenue Requirements. The expected revenue requirements for the Program are $5,969,160 for the first year and peak in 2012 at $16,883,938 based upon current Program assumptions.

Method for Recovery of Direct Cost

PSE&G will recover the net Revenue Requirements associated with this Program through the electric RGGI Recovery Charge (RRC), which was proposed in the Company's Carbon Abatement Filing on June 23, 2008. This will be a new charge in the Company's electric tariff, applicable to all electric rate schedules on an equal cents per kilowatt-hour. The Demand Response Program will be a component of the electric RRC. PSE&G is proposing that it would implement the Demand Response component of the electric RRC simultaneously with Board approval of this Program based upon forecasted expenditures and usage for the first year of the Program. The calculation of the proposed Demand Response component of the electric RRC is shown in Schedule SS–3. The Revenue Requirements for each initial and all subsequent annual periods, are divided by the current forecasted kilowatt-hours sales to determine the Demand Response Component of the electric RRC without the New Jersey Energy Sales and Use Tax (SUT) applied. The one-year forecasted kilowatt-hours sales used for this analysis are consistent with those filed in the Company's most recently filed Remediation Adjustment Charge (RAC) 15 filing (BPU Docket No. ER07120970). This same level of sales is held constant for all subsequent annual periods for illustrative purposes only. Then the current SCC rate is subtracted from the electric RRC to reflect its elimination and the change in electric rates is determined (See Schedule SS–4). The change in electric rates is then applied to all the class average rates and the percentage change from the current class average rate is calculated. In addition, the annual bill impacts for the average RS customer are calculated. The first year's change to the RS average annual bill is $0.12, or 0.011%. The maximum impact to the RS average annual bill occurs in 2012 and is $1.96 or 0.157%. The electronic version of this filing contains the supporting detailed assumptions and calculations for Schedules SS-2 through SS-4 in electronic workpapers labeled WP_FAL 1.xls and WP_SS 1.xls.

The cumulative rate impacts of this Program along with the Company's Solar Loan Program and its recent Carbon Abatement Program can be found on Schedule SS-5. The supporting detailed calculations can be found in the electronic workpaper WP_SS 2.xls.

Under the Company's proposal, any over/under recovery of the actual revenue requirements compared to revenues would be deferred. PSE&G's latest approved WACC would be applicable as the carrying charge on any over/under recovered balance on a monthly basis. The calculation deriving the current WACC value of 11.3092% per year or 0.9424% monthly is shown in Schedule SS-2a. The monthly WACC rate would be multiplied by the average monthly deferred balance. The carrying charge on the over/under recovery balance would be added monthly to the deferred balance. At the end of the initial and each subsequent recovery period, nominally one year, the corresponding deferred balance would be included with forecasted revenue requirements for the succeeding period for the purpose of setting the revised electric RRC.

This concludes my testimony at this time.

Schedule Index

Electronic Workpaper Index

QUALIFICATIONS
OF
STEPHEN SWETZ
MANAGER – RATES AND REGULATION

My name is Stephen Swetz and I am the Manager – Rates and Regulation for Public Service Electric and Gas Company (PSE&G, the Company).

EDUCATIONAL BACKGROUND

I graduated from Worcester Polytechnic Institute with a Bachelor of Science degree in Mechanical Engineering. I also earned the degree of Master of Business Administration from Fairleigh Dickinson University.

WORK EXPERIENCE

I have over 20 years experience in Rates, Analysis, and Operations for three Fortune 500 companies. Since 1991, I have work in various positions at PSE&G and affiliates of PSE&G. I have held positions in Rates & Regulation, Pricing, Corporate Planning & Finance with over thirteen years of direct experience in Northeastern retail and wholesale electric and gas markets. I am presently the Manager – Rates and Regulation and contribute to the development and implementation of the Company’s electric and gas rates. I have contributed to the Company’s filings to the New Jersey Board of Public Utilities; including the unbundling electric rates, Off Tariff Rate Agreements, and more recently, PSE&G's Solar Loan and Carbon Abatement Programs. I have led in various economic analyses, asset valuations, rate design and pricing efforts and participated in electric and gas marginal cost studies

I am an active participant of the American Gas Association's Rate and Strategic Issues Committee and the Economic Regulation and Committee of the Edison Electric Institute.

PSE&G Demand Response Program
Weighted Average Cost of Capital (WACC)

Schedule SS - 2

	Percent	Cost	Weighted Cost	Revenue Conversion Factor	Pre-Tax Weighted Cost	Discount Rate
Long-term Debt	50.6434%	6.1900%	3.1348%	1.0000	3.1348%	
Customer Deposits	0.6831%	2.9400%	0.0201%	1.0000	0.0201%	
Sub-total	51.3265%		3.1549%		3.1549%	1.8587%
Preferred Stock	1.2708%	5.0300%	0.0639%	1.6973	0.1085%	0.0639%
Common Equity[1]	47.4027%	11.0000%	5.2143%	1.6973	8.8504%	5.2143%
Total	100.0000%		8.4331%		12.1138%	7.1370%
Monthly WACC					1.0095%	

Reflects a tax rate of 41.084%

Per the latest base rate case: BPU Docket No. GR05100845, OAL Docket No. PUC-1747-06

[1] 100 basis points added to the cost of Common Equity to represent the incentive portion of the DR revenue

PSE&G Demand Response Program

Schedule SS - 2a

Weighted Average Cost of Capital (WACC) - w/o Basis Point Adjustment

	Percent	Cost	Weighted Cost	Revenue Conversion Factor	Pre-Tax Weighted Cost	Discount Rate
Long-term Debt	50.6434%	6.1900%	3.1348%	1.0000	3.1348%	
Customer Deposits	0.6831%	2.9400%	0.0201%	1.0000	0.0201%	
Sub-total	51.3265%		3.1549%		3.1549%	1.8587%
Preferred Stock	1.2708%	5.0300%	0.0639%	1.6973	0.1085%	0.0639%
Common Equity	47.4027%	10.0000%	4.7403%	1.6973	8.0458%	4.7403%
Total	100.0000%		7.9591%		11.3092%	6.6629%
Monthly WACC					0.9424%	

Reflects a tax rate of 41.084%

Per the latest base rate case: BPU Docket No. GR05100845, OAL Docket No. PUC-1747-06

PSE&G Demand Response Program

Revenue Requirements Summary

($'s unless otherwise noted)

Monthly Pre-Tax WACC	1.00948%
Income Tax Rate	41.084%
Annual kWh Sales (000)	44,695,463

	Dec-08	
Projected SCC Deferred Balance	(3,616,000)	under/(over) recovered
Accumulated Interest	(215,000)	due/(payable)
SCC Def. Bal. & Accum. Int.	(3,831,000)	under/(over) recovered

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
	Program Investment	Capitalized IT Costs	Gross Plant	Program Investment Amortization / Depreciation	IT Cost Amortization	Accumulated Amortization	Net Plant	Tax Depreciation	Deferred Income Tax	Accumulated Deferred Income Tax	Net Investment	Return Requirement	DR Revenue Credited to Customers	Customer Incentives	Administrative costs	Revenue Requirements	Legacy Res. A/C Cycling Customer Incentives	Legacy Res A/C Cycling Admin. Costs	Revenue Requirements Incl. Legacy Res A/C Program	Annual Rate w/o SUT ($/kWh)
Monthly Calculations																				
Jan-09	558,315	-	558,315	-	-	-	558,315	76,853	31,574	31,574	526,741	2,659	-	9,000	314,077	325,735	-	49,004	374,739	
Feb-09	4,058,315	-	4,616,630	3,102	-	3,102	4,613,529	76,853	30,300	61,874	4,551,655	25,633	-	9,000	387,544	425,278	-	49,004	474,282	
Mar-09	558,315	1,000,000	6,174,946	33,287	-	36,389	6,138,557	76,853	17,899	79,773	6,058,784	53,555	-	9,000	862,893	958,735	-	49,004	1,007,738	
Apr-09	1,058,315	-	7,233,261	36,389	16,667	89,444	7,143,817	76,853	9,777	89,550	7,054,267	66,187	-	9,000	363,082	491,324	-	49,004	540,328	
May-09	3,558,315	-	10,791,576	41,574	16,667	147,684	10,643,892	76,853	7,647	97,196	10,546,696	88,839	-	9,000	363,271	519,351	-	49,004	568,354	
Jun-09	593,298	-	11,384,874	57,175	16,667	221,526	11,163,348	76,853	1,237	98,433	11,064,915	109,082	149,700	229,406	363,460	626,091	694,675	49,004	1,369,769	
Jul-09	593,298	-	11,978,173	60,472	16,667	298,664	11,679,508	76,853	(117)	98,316	11,581,192	114,304	154,690	241,763	363,649	642,165	689,851	49,004	1,381,019	
Aug-09	593,298	-	12,571,471	63,768	16,667	379,099	12,192,372	76,853	(1,471)	96,845	12,095,527	119,506	154,690	254,120	363,839	663,209	685,026	49,004	1,397,239	
Sep-09	1,093,298	-	13,664,769	67,064	16,667	462,829	13,201,940	76,853	(2,826)	94,019	13,107,921	127,212	389,375	266,478	364,028	452,073	680,202	49,004	1,181,278	
Oct-09	593,298	-	14,258,067	72,443	16,667	551,939	13,706,128	76,853	(5,036)	88,983	13,617,145	134,892	154,690	9,000	364,217	442,529	-	49,004	491,532	
Nov-09	593,298	-	14,851,365	75,739	16,667	644,345	14,207,021	76,853	(6,390)	82,593	14,124,427	140,023	149,700	9,000	364,406	456,135	-	49,004	505,138	
Dec-09	593,298	-	15,444,664	79,035	16,667	740,047	14,704,617	76,853	(7,744)	74,849	14,629,767	145,134	154,690	9,000	364,595	459,741	-	49,004	508,744	
Jan-10	932,880	-	16,377,543	82,331	16,667	839,045	15,538,498	225,164	51,834	126,683	15,411,815	151,632	154,690	16,879	439,455	552,274	-	47,022	599,296	
Feb-10	9,932,880	-	26,310,423	87,514	16,667	943,226	25,367,197	225,164	49,705	176,388	25,190,809	204,938	139,720	16,879	667,203	853,481	-	47,022	900,503	
Mar-10	932,880	-	27,243,302	167,697	16,667	1,127,589	26,115,713	225,164	16,763	193,151	25,922,562	257,990	154,690	16,879	1,090,295	1,394,838	-	47,022	1,441,860	
Apr-10	932,880	-	28,176,182	172,879	16,667	1,317,135	26,859,046	225,164	14,633	207,784	26,651,262	265,361	149,700	16,879	590,516	912,602	-	47,022	959,624	
May-10	932,880	-	29,109,061	178,062	16,667	1,511,864	27,597,197	225,164	12,504	220,288	27,376,909	272,702	154,690	16,879	590,736	920,356	-	47,022	967,378	
Jun-10	932,880	-	30,041,941	183,245	16,667	1,711,776	28,330,165	225,164	10,375	230,663	28,099,502	280,012	624,088	866,334	590,957	1,313,126	611,458	47,022	1,971,606	
Jul-10	932,880	-	30,974,820	188,427	16,667	1,916,870	29,057,951	225,164	8,246	238,909	28,819,042	287,291	644,891	883,819	591,177	1,322,489	602,413	47,022	1,971,924	
Aug-10	932,880	-	31,907,700	193,610	16,667	2,127,147	29,780,553	225,164	6,116	245,025	29,535,528	294,539	644,891	901,303	591,397	1,352,625	593,367	47,022	1,993,014	
Sep-10	932,880	-	32,840,579	198,793	16,667	2,342,606	30,497,973	225,164	3,987	249,012	30,248,961	301,756	1,742,874	918,787	591,618	284,746	584,322	47,022	916,090	
Oct-10	932,880	-	33,773,459	203,975	16,667	2,563,248	31,210,211	225,164	1,858	250,870	30,959,341	308,943	644,891	16,879	591,838	493,411	-	47,022	540,433	
Nov-10	932,880	-	34,706,339	209,158	16,667	2,789,073	31,917,266	225,164	(271)	250,599	31,666,667	316,099	624,088	16,879	592,058	526,773	-	47,022	573,795	
Dec-10	932,880	-	35,639,218	214,341	16,667	3,020,080	32,619,138	225,164	(2,401)	248,198	32,370,940	323,223	644,891	16,879	592,279	518,498	-	47,022	565,520	
	Cumulative Programs	Cumulative Programs	Prior Month + (Col 1 + Col 2)	Cumulative Programs	1/60 of Each Prior 60 Months of Col 2 (5 year amortization)	Prior Month + (Col 4 + Col 5)	Col 3 - Col 6	Cumulative Programs	-(Col 4 + Col 5 - Col 8) * Income Tax Rate	Prior Month + Col 9	Col 7 - Col 10	(Prior Col 11 + Col 11) / 2 * Monthly Pre Tax WACC	Cumulative Programs	Cumulative Programs	Cumulative Programs	Col 4 + Col 5 + Col 12 - Col 13 + Col 14 + Col 15	Program Assumption	Program Assumption	Col 16 + Col 17 + Col 18 + SCC Def. Bal. & Accum. Int. (2009 Only)	Col 19 / [Annual kWh Sales] (Rnd to 6 dec.)
Annual Summary																				
2009	14,444,664	1,000,000	15,444,664	590,047	150,000	740,047	14,704,617	922,233	74,849	74,849	14,629,767	1,127,025	1,307,535	1,063,767	4,839,060	6,462,365	2,749,754	588,042	5,969,160	0.000134
2010	20,194,554	-	35,639,218	2,080,033	200,000	3,020,080	32,619,138	2,701,971	173,349	248,198	32,370,940	3,264,484	6,324,105	3,705,276	7,519,530	10,445,219	2,391,560	564,262	13,401,041	0.000300
2011	20,931,195	-	56,570,413	3,594,260	200,000	6,814,340	49,756,073	4,392,061	245,601	493,799	49,262,274	5,232,659	9,755,083	5,957,775	8,986,738	14,216,349	1,758,396	507,002	16,481,747	0.000369
2012	21,221,059	-	77,791,472	5,194,782	200,000	12,209,122	65,582,350	6,003,390	250,040	743,839	64,838,510	7,192,474	15,211,396	8,071,841	10,009,498	15,457,200	1,005,836	420,902	16,883,938	0.000378
2013	15,148,338	-	92,939,810	6,307,297	200,000	18,716,420	74,223,391	7,234,031	298,571	1,042,410	73,180,980	8,365,640	20,291,526	8,950,457	9,786,901	13,318,769	271,360	340,703	13,930,831	0.000312
2014	-	-	92,939,810	6,854,321	50,000	25,620,740	67,319,070	7,222,580	130,754	1,173,164	66,145,906	8,437,524	23,202,108	8,942,461	6,770,987	7,853,184	0	-	7,853,184	0.000176
2015	-	-	92,939,810	6,854,321	-	32,475,061	60,464,749	6,490,092	(149,640)	1,023,524	59,441,225	7,606,662	24,733,660	8,942,461	7,016,399	5,686,182	0	-	5,686,182	0.000127
2016	-	-	92,939,810	6,854,321	-	39,329,382	53,610,429	5,984,769	(357,247)	666,278	52,944,151	6,807,047	25,657,255	8,942,461	7,270,695	4,217,269	0	-	4,217,269	0.000094
2017	-	-	92,939,810	6,854,321	-	46,183,702	46,756,108	5,651,951	(493,982)	172,296	46,583,812	6,028,289	26,495,259	8,942,461	7,534,197	2,864,009	0	-	2,864,009	0.000064
2018	-	-	92,939,810	6,854,321	-	53,038,023	39,901,787	5,476,458	(566,081)	(393,785)	40,295,573	5,262,180	27,422,652	8,942,461	7,807,238	1,443,548	0	-	1,443,548	0.000032
2009-2018	91,939,810	1,000,000		52,038,023	1,000,000			52,079,535	(393,785)				180,400,580	72,461,421	77,541,244	81,964,094	8,176,905	2,420,911	88,730,910	

Note: Totals may not foot due to rounding

PSE&G Demand Response Program
Residential A/C Cycling Revenue Requirements Calculation

($'s unless otherwise noted)

Monthly Pre-Tax WACC	1.00948%
Income Tax Rate	41.084%
Annual kWh Sales (000)	44,695,463

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Program Investment	Capitalized IT Costs	Gross Plant	Program Investment Amortization / Depreciation	IT Cost Amortization	Accumulated Amortization	Net Plant	Tax Depreciation	Deferred Income Tax	Accumulated Deferred Income Tax	Net Investment	Return Requirement	DR Revenue Credited to Customers	Customer Incentives	Administrative costs	Revenue Requirements	Annual Rate w/o SUT ($/kWh)
Monthly Calculations																	
Jan-09	352,005		352,005	-	-	-	352,005	27,600	11,339	11,339	340,666	1,719	-	9,000	105,316	116,036	
Feb-09	352,005		704,010	1,956	-	1,956	702,055	27,600	10,536	21,875	680,180	5,153	-	9,000	105,316	121,425	
Mar-09	352,005	600,000	1,656,016	3,911	-	5,867	1,650,149	27,600	9,732	31,608	1,618,541	11,603	-	9,000	105,316	129,830	
Apr-09	352,005		2,008,021	5,867	10,000	21,734	1,986,287	27,600	4,821	36,428	1,949,859	18,011	-	9,000	105,316	148,194	
May-09	352,005		2,360,026	7,822	10,000	39,556	2,320,470	27,600	4,017	40,445	2,280,025	21,350	-	9,000	105,316	153,489	
Jun-09	352,005		2,712,031	9,778	10,000	59,334	2,652,698	27,600	3,214	43,659	2,609,039	24,677	10,734	44,158	105,316	183,196	
Jul-09	352,005		3,064,037	11,734	10,000	81,067	2,982,969	27,600	2,410	46,069	2,936,900	27,993	11,092	50,018	105,316	193,969	
Aug-09	352,005		3,416,042	13,689	10,000	104,756	3,311,285	27,600	1,607	47,676	3,263,609	31,296	11,092	55,878	105,316	205,088	
Sep-09	352,005		3,768,047	15,645	10,000	130,401	3,637,646	27,600	803	48,480	3,589,316	34,589	27,919	61,738	105,316	199,368	
Oct-09	352,005		4,120,052	17,600	10,000	158,001	3,962,051	27,600	0	48,480	3,913,571	37,869	11,092	9,000	105,316	168,694	
Nov-09	352,005		4,472,057	19,556	10,000	187,557	4,284,500	27,600	(803)	47,676	4,236,824	41,138	10,734	9,000	105,316	174,277	
Dec-09	352,005		4,824,063	21,511	10,000	219,069	4,604,994	27,600	(1,607)	46,069	4,558,925	44,396	11,092	9,000	105,316	179,132	
Jan-10	683,140		5,507,203	23,467	10,000	252,536	5,254,667	83,597	20,596	66,665	5,188,002	49,197	11,092	16,879	174,898	263,349	
Feb-10	683,140		6,190,343	27,262	10,000	289,798	5,900,545	83,597	19,036	85,701	5,814,843	55,536	10,018	16,879	174,898	274,557	
Mar-10	683,140		6,873,482	31,057	10,000	330,855	6,542,627	83,597	17,477	103,178	6,439,449	61,852	11,092	16,879	174,898	283,595	
Apr-10	683,140		7,556,622	34,853	10,000	375,708	7,180,914	83,597	15,918	119,096	7,061,818	68,146	10,734	16,879	174,898	294,042	
May-10	683,140		8,239,762	38,648	10,000	424,356	7,815,406	83,597	14,359	133,455	7,681,951	74,418	11,092	16,879	174,898	303,751	
Jun-10	683,140		8,922,902	42,443	10,000	476,799	8,446,103	83,597	12,799	146,255	8,299,849	80,667	78,136	153,117	174,898	382,988	
Jul-10	683,140		9,606,042	46,238	10,000	533,037	9,073,005	83,597	11,240	157,495	8,915,510	86,893	80,741	164,104	174,898	401,392	
Aug-10	683,140		10,289,182	50,034	10,000	593,071	9,696,111	83,597	9,681	167,176	9,528,935	93,096	80,741	175,090	174,898	422,378	
Sep-10	683,140		10,972,322	53,829	10,000	656,900	10,315,422	83,597	8,122	175,298	10,140,125	99,278	218,208	186,077	174,898	305,873	
Oct-10	683,140		11,655,462	57,624	10,000	724,524	10,930,938	83,597	6,563	181,860	10,749,078	105,436	80,741	16,879	174,898	284,097	
Nov-10	683,140		12,338,602	61,419	10,000	795,943	11,542,659	83,597	5,003	186,863	11,355,796	111,572	78,136	16,879	174,898	296,632	
Dec-10	683,140		13,021,742	65,214	10,000	871,157	12,150,584	83,597	3,444	190,308	11,960,277	117,686	80,741	16,879	174,898	303,936	
	Program Assumption	Program Assumption	Prior Month + (Col 1 + Col 2)	1/180 of each Prior 180 Months from Col 1 (15 year depreciation)	1/60 of Each Prior 60 Months of Col 2 (5 year amortization)	Prior Month + (Col 4 + Col 5)	Col 3 - Col 6	See Schedule SS - XX for Details	-(Col 4 + Col 5 - Col 8) * Income Tax Rate	Prior Month + Col 9	Col 7 - Col 10	(Prior Col 11 + Col 11) / 2 * Monthly Pre Tax WACC	Program Assumption	Program Assumption	Program Assumption	Col 4 + Col 5 + Col 12 - Col 13 + Col 14 + Col 15	Col 16 / [Annual kWh Sales] (Rnd to 6 dec.)
Annual Summary																	
2009	4,224,063	600,000	4,824,063	129,069	90,000	219,069	4,604,994	331,203	46,069	46,069	4,558,925	299,794	93,753	283,792	1,263,796	1,972,698	0.000044
2010	8,197,679	-	13,021,742	532,089	120,000	871,157	12,150,584	1,003,170	144,238	190,308	11,960,277	1,003,776	751,470	813,421	2,098,774	3,816,591	0.000085
2011	14,706,345	-	27,728,087	1,277,477	120,000	2,268,634	25,459,453	1,990,454	243,619	433,926	25,025,526	2,245,976	1,686,746	1,731,025	3,662,300	7,350,031	0.000164
2012	15,221,059	-	42,949,145	2,273,627	120,000	4,662,261	38,286,884	3,253,310	353,192	787,119	37,499,766	3,793,075	3,849,333	2,645,091	3,666,280	8,648,741	0.000194
2013	15,148,338	-	58,097,484	3,286,142	120,000	8,068,403	50,029,080	4,453,759	430,403	1,217,521	48,811,559	5,233,738	6,633,426	3,523,707	3,661,317	9,191,477	0.000206
2014	-	-	58,097,484	3,833,166	30,000	11,931,569	46,165,915	4,738,939	359,803	1,577,324	44,588,590	5,656,332	9,065,991	3,515,711	422,864	4,392,082	0.000098
2015	-	-	58,097,484	3,833,166	-	15,764,734	42,332,749	4,246,289	169,728	1,747,052	40,585,697	5,158,904	10,102,748	3,515,711	437,664	2,842,697	0.000064
2016	-	-	58,097,484	3,833,166	-	19,597,900	38,499,584	3,870,329	15,268	1,762,320	36,737,263	4,683,359	10,480,001	3,515,711	452,982	2,005,217	0.000045
2017	-	-	58,097,484	3,833,166	-	23,431,066	34,666,418	3,599,031	(96,192)	1,666,129	33,000,289	4,223,920	10,822,294	3,515,711	468,837	1,219,339	0.000027
2018	-	-	58,097,484	3,833,166	-	27,264,231	30,833,252	3,443,161	(160,230)	1,505,899	29,327,353	3,775,111	11,201,098	3,515,711	485,246	408,135	0.000009
2009-2018	57,497,484	600,000		26,664,231	600,000			30,929,646	1,505,899				64,686,859	26,575,591	16,620,060	41,847,007	

Note: Totals may not foot due to rounding

PSE&G Demand Response Program
Residential Pool Pump Load Control Revenue Requirements Calculation

($'s unless otherwise noted)

Monthly Pre-Tax WACC	1.00948%
Income Tax Rate	41.084%
Annual kWh Sales (000)	44,695,463

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Program Investment	Capitalized IT Costs	Gross Plant	Program Investment Amortization / Depreciation	IT Cost Amortization	Accumulated Amortization	Net Plant	Tax Depreciation	Deferred Income Tax	Accumulated Deferred Income Tax	Net Investment	Return Requirement	DR Revenue Credited to Customers	Customer Incentives	Administrative costs	Revenue Requirements	Annual Rate w/o SUT ($/kWh)
Monthly Calculations																	
Jan-09	-		-	-	-	-	-	1,854	762	762	(762)	(4)	-	-	71,604	71,600	
Feb-09	-		-	-	-	-	-	1,854	762	1,523	(1,523)	(12)	-	-	71,698	71,687	
Mar-09	-	50,000	50,000	-	-	-	50,000	1,854	762	2,285	47,715	233	-	-	71,793	72,026	
Apr-09	-		50,000	-	833	833	49,167	1,854	419	2,704	46,463	475	-	-	71,887	73,196	
May-09	-		50,000	-	833	1,667	48,333	1,854	419	3,123	45,210	463	-	-	71,982	73,278	
Jun-09	34,983		84,983	-	833	2,500	82,483	1,854	419	3,542	78,941	627	-	748	72,077	74,284	
Jul-09	34,983		119,966	194	833	3,528	116,438	1,854	339	3,882	112,557	967	-	1,495	72,171	75,660	
Aug-09	34,983		154,949	389	833	4,750	150,199	1,854	260	4,141	146,058	1,305	-	2,243	72,266	77,036	
Sep-09	34,983		189,932	583	833	6,166	183,766	1,854	180	4,321	179,445	1,643	-	2,990	72,360	78,410	
Oct-09	34,983		224,915	777	833	7,777	217,138	1,854	100	4,421	212,718	1,979	-	-	72,455	76,045	
Nov-09	34,983		259,898	972	833	9,582	250,316	1,854	20	4,441	245,876	2,315	-	-	72,549	76,669	
Dec-09	34,983		294,881	1,166	833	11,581	283,300	1,854	(60)	4,381	278,919	2,649	-	-	72,644	77,292	
Jan-10	36,208		331,089	1,360	833	13,775	317,313	5,082	1,187	5,567	311,746	2,981	-	-	73,288	78,463	
Feb-10	36,208		367,296	1,562	833	16,170	351,126	5,082	1,104	6,672	344,455	3,312	-	-	73,398	79,105	
Mar-10	36,208		403,504	1,763	833	18,766	384,738	5,082	1,021	7,693	377,045	3,642	-	-	73,509	79,746	
Apr-10	36,208		439,711	1,964	833	21,563	418,148	5,082	939	8,632	409,516	3,970	-	-	73,619	80,386	
May-10	36,208		475,919	2,165	833	24,562	451,357	5,082	856	9,488	441,869	4,297	-	-	73,729	81,025	
Jun-10	36,208		512,127	2,366	833	27,761	484,365	5,082	774	10,261	474,104	4,623	4,990	9,718	73,839	86,390	
Jul-10	36,208		548,334	2,567	833	31,162	517,172	5,082	691	10,952	506,220	4,948	5,156	10,465	73,949	87,607	
Aug-10	36,208		584,542	2,769	833	34,764	549,778	5,082	608	11,561	538,217	5,272	5,156	11,213	74,060	88,990	
Sep-10	36,208		620,749	2,970	833	38,567	582,182	5,082	526	12,086	570,096	5,594	13,934	11,960	74,170	81,592	
Oct-10	36,208		656,957	3,171	833	42,571	614,386	5,082	443	12,529	601,857	5,915	5,156	-	74,280	79,043	
Nov-10	36,208		693,165	3,372	833	46,776	646,388	5,082	360	12,890	633,499	6,235	4,990	-	74,390	79,841	
Dec-10	36,208		729,372	3,573	833	51,183	678,189	5,082	278	13,167	665,022	6,554	5,156	-	74,500	80,305	
	Program Assumption	Program Assumption	Prior Month + (Col 1 + Col 2)	1/180 of each Prior 180 Months from Col 1 (15 year depreciation)	1/60 of Each Prior 60 Months of Col 2 (5 year amortization)	Prior Month + (Col 4 + Col 5)	Col 3 - Col 6	See Schedule SS - XX for Details	-(Col 4 + Col 5 - Col 8) * Income Tax Rate	Prior Month + Col 9	Col 7 - Col 10	(Prior Col 11 + Col 11) / 2 * Monthly Pre Tax WACC	Program Assumption	Program Assumption	Program Assumption	Col 4 + Col 5 + Col 12 - Col 13 + Col 14 + Col 15	Col 16 / [Annual kWh Sales] (Rnd to 6 dec.)
Annual Summary																	
2009	244,881	50,000	294,881	4,081	7,500	11,581	283,300	22,244	4,381	4,381	278,919	12,640	-	7,475	865,486	897,183	0.000020
2010	434,491	-	729,372	29,602	10,000	51,183	678,189	60,988	8,787	13,167	665,022	57,344	44,538	43,355	886,731	982,494	0.000022
2011	224,851	-	954,223	55,909	10,000	117,092	837,131	83,057	7,045	20,212	816,919	96,669	99,151	74,750	148,199	286,377	0.000006
2012	-	-	954,223	60,282	10,000	187,374	766,849	83,116	5,273	25,485	741,364	94,383	148,949	74,750	133,900	224,365	0.000005
2013	-	-	954,223	60,282	10,000	257,655	696,567	75,401	2,103	27,588	668,980	85,423	175,656	74,750	142,520	197,318	0.000004
2014	-	-	954,223	60,282	2,500	320,437	633,786	65,580	1,150	28,738	605,048	77,099	181,804	74,750	151,579	184,406	0.000004
2015	-	-	954,223	60,282	-	380,718	573,504	57,099	(1,308)	27,430	546,074	69,722	188,167	74,750	161,098	177,685	0.000004
2016	-	-	954,223	60,282	-	441,000	513,223	54,091	(2,543)	24,887	488,336	62,653	195,194	74,750	171,098	173,589	0.000004
2017	-	-	954,223	60,282	-	501,281	452,941	53,374	(2,838)	22,049	430,893	55,677	201,569	74,750	181,600	170,739	0.000004
2018	-	-	954,223	60,282	-	561,563	392,660	53,393	(2,830)	19,218	373,441	48,718	208,624	74,750	192,628	167,753	0.000004
2009-2018	904,223	50,000		511,563	50,000			608,341	19,218				1,443,651	648,830	3,034,839	3,461,909	

Note: Totals may not foot due to rounding

PSE&G Demand Response Program

Small Commercial A/C Cycling Revenue Requirements Calculation

($'s unless otherwise noted)

Monthly Pre-Tax WACC	1.00948%
Income Tax Rate	41.084%
Annual kWh Sales (000)	44,695,463

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Program Investment	Capitalized IT Costs	Gross Plant	Program Investment Amortization / Depreciation	IT Cost Amortization	Accumulated Amortization	Net Plant	Tax Depreciation	Deferred Income Tax	Accumulated Deferred Income Tax	Net Investment	Return Requirement	DR Revenue Credited to Customers	Customer Incentives	Administrative costs	Revenue Requirements	Annual Rate w/o SUT ($/kWh)
Monthly Calculations																	
Jan-09	206,310		206,310	-	-	-	206,310	11,149	4,580	4,580	201,730	1,018	-	-	71,604	72,622	
Feb-09	206,310		412,620	1,146	-	1,146	411,474	11,149	4,109	8,690	402,784	3,051	-	-	71,698	75,896	
Mar-09	206,310	50,000	668,930	2,292	-	3,439	665,492	11,149	3,639	12,328	653,163	5,330	-	-	71,793	79,415	
Apr-09	206,310		875,240	3,439	833	7,710	867,530	11,149	2,825	15,154	852,376	7,599	-	-	71,887	83,758	
May-09	206,310		1,081,550	4,585	833	13,128	1,068,422	11,149	2,354	17,508	1,050,913	9,607	-	-	71,982	87,007	
Jun-09	206,310		1,287,860	5,731	833	19,693	1,268,168	11,149	1,884	19,392	1,248,776	11,607	9,786	34,500	72,077	114,962	
Jul-09	206,310		1,494,170	6,877	833	27,403	1,466,767	11,149	1,413	20,805	1,445,963	13,601	10,112	40,250	72,171	123,621	
Aug-09	206,310		1,700,480	8,023	833	36,259	1,664,221	11,149	942	21,746	1,642,474	15,589	10,112	46,000	72,266	132,599	
Sep-09	206,310		1,906,790	9,169	833	46,262	1,860,528	11,149	471	22,217	1,838,311	17,569	25,454	51,750	72,360	126,228	
Oct-09	206,310		2,113,100	10,316	833	57,411	2,055,689	11,149	-	22,217	2,033,472	19,542	10,112	-	72,455	93,034	
Nov-09	206,310		2,319,410	11,462	833	69,706	2,249,704	11,149	(471)	21,746	2,227,958	21,509	9,786	-	72,549	96,568	
Dec-09	206,310		2,525,720	12,608	833	83,147	2,442,573	11,149	(942)	20,805	2,421,768	23,469	10,112	-	72,644	99,442	
Jan-10	213,532		2,739,252	13,754	833	97,734	2,641,518	31,609	6,993	27,798	2,613,720	25,416	10,112	-	73,288	103,180	
Feb-10	213,532		2,952,784	14,940	833	113,508	2,839,276	31,609	6,506	34,304	2,804,972	27,350	9,134	-	73,398	107,389	
Mar-10	213,532		3,166,316	16,127	833	130,468	3,035,848	31,609	6,019	40,322	2,995,526	29,277	10,112	-	73,509	109,634	
Apr-10	213,532		3,379,848	17,313	833	148,614	3,231,234	31,609	5,531	45,854	3,185,380	31,198	9,786	-	73,619	113,177	
May-10	213,532		3,593,380	18,499	833	167,947	3,425,433	31,609	5,044	50,897	3,374,536	33,111	10,112	-	73,729	116,060	
Jun-10	213,532		3,806,912	19,685	833	188,465	3,618,447	31,609	4,556	55,454	3,562,993	35,016	63,321	103,500	73,839	169,554	
Jul-10	213,532		4,020,444	20,872	833	210,170	3,810,274	31,609	4,069	59,523	3,750,751	36,915	65,431	109,250	73,949	176,388	
Aug-10	213,532		4,233,976	22,058	833	233,062	4,000,914	31,609	3,582	63,105	3,937,810	38,807	65,431	115,000	74,060	185,327	
Sep-10	213,532		4,447,508	23,244	833	257,139	4,190,369	31,609	3,094	66,199	4,124,170	40,692	176,834	120,750	74,170	82,855	
Oct-10	213,532		4,661,040	24,431	833	282,403	4,378,637	31,609	2,607	68,806	4,309,831	42,570	65,431	-	74,280	76,682	
Nov-10	213,532		4,874,572	25,617	833	308,854	4,565,718	31,609	2,120	70,926	4,494,793	44,440	63,321	-	74,390	81,960	
Dec-10	213,532		5,088,104	26,803	833	336,490	4,751,614	31,609	1,632	72,558	4,679,056	46,304	65,431	-	74,500	83,009	
	Program Assumption	Program Assumption	Prior Month + (Col 1 + Col 2)	1/180 of each Prior 180 Months from Col 1 (15 year depreciation)	1/60 of Each Prior 60 Months of Col 2 (5 year amortization)	Prior Month + (Col 4 + Col 5)	Col 3 - Col 6	See Schedule SS - XX for Details	-(Col 4 + Col 5 - Col 8) * Income Tax Rate	Prior Month + Col 9	Col 7 - Col 10	(Prior Col 11 + Col 11) / 2 * Monthly Pre Tax WACC	Program Assumption	Program Assumption	Program Assumption	Col 4 + Col 5 + Col 12 - Col 13 + Col 14 + Col 15	Col 16 / [Annual kWh Sales] (Rnd to 6 dec.)

Annual Summary

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
2009	2,475,720	50,000	2,525,720	75,647	7,500	83,147	2,442,573	133,786	20,805	20,805	2,421,768	149,492	85,474	172,500	865,486	1,185,151	0.000027
2010	2,562,384	-	5,088,104	243,343	10,000	336,490	4,751,614	379,313	51,753	72,558	4,679,056	431,097	614,457	448,500	886,731	1,405,215	0.000031
2011	-	-	5,088,104	335,874	10,000	682,364	4,405,740	464,701	48,819	121,377	4,284,364	542,904	1,008,994	552,000	148,199	579,983	0.000013
2012	-	-	5,088,104	335,874	10,000	1,028,237	4,059,867	415,464	28,591	149,967	3,909,899	496,317	1,222,099	552,000	133,900	305,991	0.000007
2013	-	-	5,088,104	335,874	10,000	1,374,111	3,713,993	374,621	11,811	161,778	3,552,215	451,971	1,375,701	552,000	142,520	116,664	0.000003
2014	-	-	5,088,104	335,874	2,500	1,712,484	3,375,620	334,711	(1,505)	160,273	3,215,347	409,836	1,423,849	552,000	151,579	27,940	0.000001
2015	-	-	5,088,104	335,874	-	2,048,358	3,039,746	305,704	(12,395)	147,878	2,891,868	369,907	1,473,686	552,000	161,098	(54,808)	(0.000001)
2016	-	-	5,088,104	335,874	-	2,384,232	2,703,872	297,248	(15,869)	132,009	2,571,863	330,932	1,528,716	552,000	171,098	(138,813)	(0.000003)
2017	-	-	5,088,104	335,874	-	2,720,105	2,367,999	297,496	(15,767)	116,242	2,251,757	292,161	1,578,646	552,000	181,600	(217,012)	(0.000005)
2018	-	-	5,088,104	335,874	-	3,055,979	2,032,125	297,504	(15,764)	100,478	1,931,647	253,384	1,633,903	552,000	192,628	(300,017)	(0.000007)
2009-2018	5,038,104	50,000		3,005,979	50,000			3,300,547	100,478				11,945,524	5,037,000	3,034,839	2,910,294	

Note: Totals may not foot due to rounding

PSE&G Demand Response Program
C&I Curtailment Services Revenue Requirements Calculation

($'s unless otherwise noted)

Monthly Pre-Tax WACC	1.00948%
Income Tax Rate	41.084%
Annual kWh Sales (000)	44,695,463

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Program Investment	Capitalized IT Costs	Gross Plant	Program Investment Amortization / Depreciation	IT Cost Amortization	Accumulated Amortization	Net Plant	Tax Depreciation	Deferred Income Tax	Accumulated Deferred Income Tax	Net Investment	Return Requirement	DR Revenue Credited to Customers	Customer Incentives	Administrative costs	Revenue Requirements	Annual Rate w/o SUT ($/kWh)
Monthly Calculations																	
Jan-09	-		-	-	-	-	-	17,500	7,190	7,190	(7,190)	(36)	-	-	63,224	63,188	
Feb-09	3,000,000		3,000,000	-	-	-	3,000,000	17,500	7,190	14,379	2,985,621	15,033	-	-	136,502	151,535	
Mar-09	-	300,000	3,300,000	25,000	-	25,000	3,275,000	17,500	(3,081)	11,298	3,263,702	31,543	-	-	111,662	168,205	
Apr-09	-		3,300,000	25,000	5,000	55,000	3,245,000	17,500	(5,136)	6,163	3,238,837	32,821	-	-	111,662	174,483	
May-09	-		3,300,000	25,000	5,000	85,000	3,215,000	17,500	(5,136)	1,027	3,213,973	32,570	-	-	111,662	174,232	
Jun-09	-		3,300,000	25,000	5,000	115,000	3,185,000	17,500	(5,136)	(4,108)	3,189,108	32,319	129,180	150,000	111,662	194,801	
Jul-09	-		3,300,000	25,000	5,000	145,000	3,155,000	17,500	(5,136)	(9,244)	3,164,244	32,068	133,486	150,000	111,662	190,244	
Aug-09	-		3,300,000	25,000	5,000	175,000	3,125,000	17,500	(5,136)	(14,379)	3,139,379	31,817	133,486	150,000	111,662	189,993	
Sep-09	-		3,300,000	25,000	5,000	205,000	3,095,000	17,500	(5,136)	(19,515)	3,114,515	31,566	336,002	150,000	111,662	(12,774)	
Oct-09	-		3,300,000	25,000	5,000	235,000	3,065,000	17,500	(5,136)	(24,650)	3,089,650	31,315	133,486	-	111,662	39,491	
Nov-09	-		3,300,000	25,000	5,000	265,000	3,035,000	17,500	(5,136)	(29,786)	3,064,786	31,064	129,180	-	111,662	43,546	
Dec-09	-		3,300,000	25,000	5,000	295,000	3,005,000	17,500	(5,136)	(34,921)	3,039,921	30,813	133,486	-	111,662	38,989	
Jan-10	-		3,300,000	25,000	5,000	325,000	2,975,000	69,250	16,125	(18,796)	2,993,796	30,455	133,486	-	115,570	42,538	
Feb-10	9,000,000		12,300,000	25,000	5,000	355,000	11,945,000	69,250	16,125	(2,670)	11,947,670	75,416	120,568	-	343,098	327,946	
Mar-10	-		12,300,000	100,000	5,000	460,000	11,840,000	69,250	(14,688)	(17,358)	11,857,358	120,154	133,486	-	265,970	357,637	
Apr-10	-		12,300,000	100,000	5,000	565,000	11,735,000	69,250	(14,688)	(32,046)	11,767,046	119,242	129,180	-	265,970	361,032	
May-10	-		12,300,000	100,000	5,000	670,000	11,630,000	69,250	(14,688)	(46,733)	11,676,733	118,330	133,486	-	265,970	355,814	
Jun-10	-		12,300,000	100,000	5,000	775,000	11,525,000	69,250	(14,688)	(61,421)	11,586,421	117,418	477,642	600,000	265,970	610,747	
Jul-10	-		12,300,000	100,000	5,000	880,000	11,420,000	69,250	(14,688)	(76,108)	11,496,108	116,507	493,563	600,000	265,970	593,914	
Aug-10	-		12,300,000	100,000	5,000	985,000	11,315,000	69,250	(14,688)	(90,796)	11,405,796	115,595	493,563	600,000	265,970	593,002	
Sep-10	-		12,300,000	100,000	5,000	1,090,000	11,210,000	69,250	(14,688)	(105,483)	11,315,483	114,683	1,333,897	600,000	265,970	(248,244)	
Oct-10	-		12,300,000	100,000	5,000	1,195,000	11,105,000	69,250	(14,688)	(120,171)	11,225,171	113,772	493,563	-	265,970	(8,821)	
Nov-10	-		12,300,000	100,000	5,000	1,300,000	11,000,000	69,250	(14,688)	(134,858)	11,134,858	112,860	477,642	-	265,970	6,188	
Dec-10	-		12,300,000	100,000	5,000	1,405,000	10,895,000	69,250	(14,688)	(149,546)	11,044,546	111,948	493,563	-	265,970	(10,645)	
	Program Assumption	Program Assumption	Prior Month + (Col 1 + Col 2)	1/120 of each Prior 120 Months from Col 1 (10 year amortization)	1/60 of Each Prior 60 Months of Col 2 (5 year amortization)	Prior Month + (Col 4 + Col 5)	Col 3 - Col 6	See Schedule SS - XX for Details	-(Col 4 + Col 5 - Col 8) * Income Tax Rate	Prior Month + Col 9	Col 7 - Col 10	(Prior Col 11 + Col 11) / 2 * Monthly Pre Tax WACC	Program Assumption	Program Assumption	Program Assumption	Col 4 + Col 5 + Col 12 - Col 13 + Col 14 + Col 15	Col 16 / [Annual kWh Sales] (Rnd to 6 dec.)
Annual Summary																	
2009	3,000,000	300,000	3,300,000	250,000	45,000	295,000	3,005,000	210,000	(34,921)	(34,921)	3,039,921	332,892	1,128,308	600,000	1,316,347	1,415,930	0.000032
2010	9,000,000	-	12,300,000	1,050,000	60,000	1,405,000	10,895,000	831,000	(114,624)	(149,546)	11,044,546	1,266,379	4,913,641	2,400,000	3,118,371	2,981,109	0.000067
2011	6,000,000	-	18,300,000	1,700,000	60,000	3,165,000	15,135,000	1,469,100	(119,513)	(269,059)	15,404,059	1,877,494	6,960,192	3,600,000	4,498,105	4,775,406	0.000107
2012	6,000,000	-	24,300,000	2,300,000	60,000	5,525,000	18,775,000	1,905,000	(186,932)	(455,991)	19,230,991	2,373,337	9,991,015	4,800,000	5,944,436	5,486,758	0.000123
2013	-	-	24,300,000	2,400,000	60,000	7,985,000	16,315,000	2,018,400	(181,427)	(637,418)	16,952,418	2,191,586	12,106,743	4,800,000	5,808,478	3,153,320	0.000071
2014	-	-	24,300,000	2,400,000	15,000	10,400,000	13,900,000	1,803,000	(251,434)	(888,852)	14,788,852	1,922,129	12,530,465	4,800,000	6,011,775	2,618,439	0.000059
2015	-	-	24,300,000	2,400,000	-	12,800,000	11,500,000	1,615,500	(322,304)	(1,211,156)	12,711,156	1,665,643	12,969,058	4,800,000	6,222,187	2,118,771	0.000047
2016	-	-	24,300,000	2,400,000	-	15,200,000	9,100,000	1,497,600	(370,742)	(1,581,898)	10,681,898	1,416,889	13,453,344	4,800,000	6,439,963	1,603,509	0.000036
2017	-	-	24,300,000	2,400,000	-	17,600,000	6,700,000	1,436,100	(396,009)	(1,977,907)	8,677,907	1,172,600	13,892,750	4,800,000	6,665,362	1,145,212	0.000026
2018	-	-	24,300,000	2,400,000	-	20,000,000	4,300,000	1,416,900	(403,897)	(2,381,804)	6,681,804	930,319	14,379,027	4,800,000	6,898,650	649,942	0.000015
2009-2018	24,000,000	300,000		19,700,000	300,000			14,202,600	(2,381,804)				102,324,545	40,200,000	52,923,673	25,948,396	

Note: Totals may not foot due to rounding

PSE&G Demand Response Program

Load Shifting Demonstration Revenue Requirements Calculation

($'s unless otherwise noted)

Monthly Pre-Tax WACC	1.00948%
Income Tax Rate	41.084%
Annual kWh Sales (000)	44,695,463

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	Program Investment	Capitalized IT Costs	Gross Plant	Program Investment Amortization / Depreciation	IT Cost Amortization	Accumulated Amortization	Net Plant	Tax Depreciation	Deferred Income Tax	Accumulated Deferred Income Tax	Net Investment	Return Requirement	DR Revenue Credited to Customers	Customer Incentives	Administrative costs	Revenue Requirements	Annual Rate w/o SUT ($/kWh)
Monthly Calculations																	
Jan-09	-		-	-	-	-	-	18,750	7,703	7,703	(7,703)	(39)	-	-	2,329	2,290	
Feb-09	500,000		500,000	-	-	-	500,000	18,750	7,703	15,407	484,594	2,407	-	-	2,329	4,736	
Mar-09	-	-	500,000	2,083	-	2,083	497,917	18,750	6,847	22,254	475,663	4,847	-	-	502,329	509,259	
Apr-09	500,000		1,000,000	2,083	-	4,167	995,833	18,750	6,847	29,101	966,732	7,280	-	-	2,329	11,692	
May-09	3,000,000		4,000,000	4,167	-	8,333	3,991,667	18,750	5,991	35,093	3,956,574	24,850	-	-	2,329	31,345	
Jun-09	-		4,000,000	16,667	-	25,000	3,975,000	18,750	856	35,949	3,939,052	39,852	-	-	2,329	58,848	
Jul-09	-		4,000,000	16,667	-	41,667	3,958,333	18,750	856	36,804	3,921,529	39,675	-	-	2,329	58,671	
Aug-09	-		4,000,000	16,667	-	58,333	3,941,667	18,750	856	37,660	3,904,006	39,499	-	-	2,329	58,494	
Sep-09	500,000		4,500,000	16,667	-	75,000	4,425,000	18,750	856	38,516	4,386,484	41,845	-	-	2,329	60,841	
Oct-09	-		4,500,000	18,750	-	93,750	4,406,250	18,750	-	38,516	4,367,734	44,186	-	-	2,329	65,265	
Nov-09	-		4,500,000	18,750	-	112,500	4,387,500	18,750	-	38,516	4,348,984	43,997	-	-	2,329	65,076	
Dec-09	-		4,500,000	18,750	-	131,250	4,368,750	18,750	-	38,516	4,330,234	43,807	-	-	2,329	64,886	
Jan-10	-		4,500,000	18,750	-	150,000	4,350,000	35,625	6,933	45,449	4,304,551	43,583	-	-	2,410	64,743	
Feb-10	-		4,500,000	18,750	-	168,750	4,331,250	35,625	6,933	52,382	4,278,868	43,324	-	-	2,410	64,484	
Mar-10	-		4,500,000	18,750	-	187,500	4,312,500	35,625	6,933	59,315	4,253,185	43,065	-	-	502,410	564,225	
Apr-10	-		4,500,000	18,750	-	206,250	4,293,750	35,625	6,933	66,248	4,227,502	42,805	-	-	2,410	63,966	
May-10	-		4,500,000	18,750	-	225,000	4,275,000	35,625	6,933	73,181	4,201,819	42,546	-	-	2,410	63,706	
Jun-10	-		4,500,000	18,750	-	243,750	4,256,250	35,625	6,933	80,114	4,176,136	42,287	-	-	2,410	63,447	
Jul-10	-		4,500,000	18,750	-	262,500	4,237,500	35,625	6,933	87,047	4,150,453	42,028	-	-	2,410	63,188	
Aug-10	-		4,500,000	18,750	-	281,250	4,218,750	35,625	6,933	93,980	4,124,770	41,768	-	-	2,410	62,929	
Sep-10	-		4,500,000	18,750	-	300,000	4,200,000	35,625	6,933	100,913	4,099,087	41,509	-	-	2,410	62,669	
Oct-10	-		4,500,000	18,750	-	318,750	4,181,250	35,625	6,933	107,846	4,073,405	41,250	-	-	2,410	62,410	
Nov-10	-		4,500,000	18,750	-	337,500	4,162,500	35,625	6,933	114,778	4,047,722	40,991	-	-	2,410	62,151	
Dec-10	-		4,500,000	18,750	-	356,250	4,143,750	35,625	6,933	121,711	4,022,039	40,731	-	-	2,410	61,892	
	Program Assumption	Program Assumption	Prior Month + (Col 1 + Col 2)	1/180 of each Prior 180 Months from Col 1 (15 year depreciation)	1/60 of Each Prior 60 Months of Col 2 (5 year amortization)	Prior Month + (Col 4 + Col 5)	Col 3 - Col 6	See Schedule SS - XX for Details	-(Col 4 + Col 5 - Col 8) * Income Tax Rate	Prior Month + Col 9	Col 7 - Col 10	(Prior Col 11 + Col 11) / 2 * Monthly Pre Tax WACC	Program Assumption	Program Assumption	Program Assumption	Col 4 + Col 5 + Col 12 - Col 13 + Col 14 + Col 15	Col 16 / [Annual kWh Sales] (Rnd to 6 dec.)
Annual Summary																	
2009	4,500,000	-	4,500,000	131,250	-	131,250	4,368,750	225,000	38,516	38,516	4,330,234	332,207	-	-	527,945	991,402	0.000022
2010	-	-	4,500,000	225,000	-	356,250	4,143,750	427,500	83,195	121,711	4,022,039	505,887	-	-	528,923	1,259,810	0.000028
2011	-	-	4,500,000	225,000	-	581,250	3,918,750	384,750	65,632	187,343	3,731,407	469,617	-	-	529,935	1,224,552	0.000027
2012	-	-	4,500,000	225,000	-	806,250	3,693,750	346,500	49,917	237,260	3,456,490	435,362	-	-	130,983	791,345	0.000018
2013	-	-	4,500,000	225,000	-	1,031,250	3,468,750	311,850	35,681	272,942	3,195,808	402,922	-	-	32,068	659,989	0.000015
2014	-	-	4,500,000	225,000	-	1,256,250	3,243,750	280,350	22,740	295,682	2,948,068	372,127	-	-	33,190	630,317	0.000014
2015	-	-	4,500,000	225,000	-	1,481,250	3,018,750	265,500	16,639	312,321	2,706,429	342,486	-	-	34,352	601,838	0.000013
2016	-	-	4,500,000	225,000	-	1,706,250	2,793,750	265,500	16,639	328,960	2,464,790	313,215	-	-	35,554	573,768	0.000013
2017	-	-	4,500,000	225,000	-	1,931,250	2,568,750	265,950	16,824	345,783	2,222,967	283,932	-	-	36,798	545,730	0.000012
2018	-	-	4,500,000	225,000	-	2,156,250	2,343,750	265,500	16,639	362,423	1,981,327	254,649	-	-	38,086	517,735	0.000012
2009-2018	4,500,000	-		2,156,250	-			3,038,400	362,423				-	-	1,927,834	7,796,488	

Note: Totals may not foot due to rounding

PSE&G Demand Response Program
Rate Impact Analysis

7% SUT Rate
6,960 Avg RS kWh / yr.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
					Class Average Rate w/SUT - $/kWh[1]											
	Electric RRC w/o SUT ($/kWh)	**Electric RRC w/ SUT ($/kWh)**	Current SCC w/ SUT ($/kWh)	**Change in Electric Rates w/ SUT ($/kWh)**	RS	RHS	RLM	GLP	LPL-S (0-749)	LPL-S (750-999)	LPL-S (1,000+)	LPL-P	HTS-S	HTS-HV	RS Average Annual Bill ($'s)	Change in RS Average Annual Bill ($'s)
Current					0.179046	0.158883	0.168359	0.171625	0.151411	0.154350	0.137599	0.129715	0.120813	0.111963	1,246.16	
2009	0.000134	0.000143	0.000123	**0.000020**	0.179066	0.158903	0.168379	0.171645	0.151431	0.154370	0.137619	0.129735	0.120833	0.111983	1,246.28	0.12
2010	0.000300	0.000321	0.000123	**0.000198**	0.179244	0.159081	0.168557	0.171823	0.151609	0.154548	0.137797	0.129913	0.121011	0.112161	1,247.54	1.38
2011	0.000369	0.000395	0.000123	**0.000272**	0.179318	0.159155	0.168631	0.171897	0.151683	0.154622	0.137871	0.129987	0.121085	0.112235	1,248.05	1.89
2012	0.000378	0.000404	0.000123	**0.000281**	0.179327	0.159164	0.168640	0.171906	0.151692	0.154631	0.137880	0.129996	0.121094	0.112244	1,248.12	1.96
2013	0.000312	0.000334	0.000123	**0.000211**	0.179257	0.159094	0.168570	0.171836	0.151622	0.154561	0.137810	0.129926	0.121024	0.112174	1,247.63	1.47
2014	0.000176	0.000188	0.000123	**0.000065**	0.179111	0.158948	0.168424	0.171690	0.151476	0.154415	0.137664	0.129780	0.120878	0.112028	1,246.61	0.45
2015	0.000127	0.000136	0.000123	**0.000013**	0.179059	0.158896	0.168372	0.171638	0.151424	0.154363	0.137612	0.129728	0.120826	0.111976	1,246.25	0.09
2016	0.000094	0.000101	0.000123	**(0.000022)**	0.179024	0.158861	0.168337	0.171603	0.151389	0.154328	0.137577	0.129693	0.120791	0.111941	1,246.01	-0.15
2017	0.000064	0.000068	0.000123	**(0.000055)**	0.178991	0.158828	0.168304	0.171570	0.151356	0.154295	0.137544	0.129660	0.120758	0.111908	1,245.78	-0.38
2018	0.000032	0.000034	0.000123	**(0.000089)**	0.178957	0.158794	0.168270	0.171536	0.151322	0.154261	0.137510	0.129626	0.120724	0.111874	1,245.54	-0.62
	From Schedule SS-3 Col 20	Col 1 * (1 + SUT Rate) Rnd 6	From Current PSE&G Elec. Tariff Sheet No. 64	Col 2 - Col 3	Current Class Avg Rate + Col 4 for Each Rate Class (Col 5 thru Col 14)										Col 5 * Avg RS kWh / yr.	Col 15 - Current RS Avg Annual Bill

	% Change from Current Class Average Rate w/SUT									
	RS	RHS	RLM	GLP	LPL-S (0-749)	LPL-S (750-999)	LPL-S (1,000+)	LPL-P	HTS-S	HTS-HV
2009	0.011%	0.013%	0.012%	0.012%	0.013%	0.013%	0.015%	0.015%	0.017%	0.018%
2010	0.111%	0.125%	0.118%	0.115%	0.131%	0.128%	0.144%	0.153%	0.164%	0.177%
2011	0.152%	0.171%	0.162%	0.158%	0.180%	0.176%	0.198%	0.210%	0.225%	0.243%
2012	0.157%	0.177%	0.167%	0.164%	0.186%	0.182%	0.204%	0.217%	0.233%	0.251%
2013	0.118%	0.133%	0.125%	0.123%	0.139%	0.137%	0.153%	0.163%	0.175%	0.188%
2014	0.036%	0.041%	0.039%	0.038%	0.043%	0.042%	0.047%	0.050%	0.054%	0.058%
2015	0.007%	0.008%	0.008%	0.008%	0.009%	0.008%	0.009%	0.010%	0.011%	0.012%
2016	-0.012%	-0.014%	-0.013%	-0.013%	-0.015%	-0.014%	-0.016%	-0.017%	-0.018%	-0.020%
2017	-0.031%	-0.035%	-0.033%	-0.032%	-0.036%	-0.036%	-0.040%	-0.042%	-0.046%	-0.049%
2018	-0.050%	-0.056%	-0.053%	-0.052%	-0.059%	-0.058%	-0.065%	-0.069%	-0.074%	-0.079%
2019	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2020	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2021	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
2022	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%

[1] All customers assumed to have BGS Supply

PSE&G Demand Response Program

Cumulative Rate Impact Analysis - Solar Program Recovery Charge (SPRC) & Electric RGGI Recovery Charge (RRC)

Rate Calculation

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Solar Revenue Requirement ($)	Carrying Charge on deferred balance ($)	SPRC Revenue Requirement ($)	SPRC w/o SUT ($/kWh)	SPRC Revenue ($)	SPRC Balance EOY Under/(Over) ($)	Carbon Abatement Electric Revenue Requirement ($)	Carbon Abatement Electric Component w/o SUT ($/kWh)	Demand Response Revenue Requirement ($)	Demand Response Component w/o SUT ($/kWh)	SPRC + Electric RRC w/o SUT ($/kWh)
2008	2,745,432	22,208	2,767,640			2,767,640					
2009	2,968,901	269,497	6,006,038	0.000134	(5,989,192)	16,846	686,981	0.000015	5,969,160	0.000134	0.000283
2010	2,072,564	297,013	2,386,423	0.000053	(2,368,860)	17,563	991,329	0.000022	13,401,041	0.000300	0.000375
2011	1,598,554	346,104	1,962,221	0.000044	(1,966,600)	(4,379)	1,470,034	0.000033	16,481,747	0.000369	0.000446
2012	1,537,407	343,206	1,876,234	0.000042	(1,877,209)	(975)	1,915,850	0.000043	16,883,938	0.000378	0.000463
2013	1,467,323	342,814	1,809,162	0.000040	(1,787,819)	21,343	1,787,950	0.000040	13,930,831	0.000312	0.000392
	From Solar Rev. Req Calc+ Prev Col E	From Solar Rev. Req Calc	Col A + Col B + Prev Col E	Col C / [Annual kWh Sales] (Rnd to 6 dec.)	=Col D * [Annual kWh Sales]	Col C + Col E	CA Sched SS-3 Col 15	Col G / [Annual kWh Sales] (Rnd to 6 dec.)	Sched SS-3 Col 19	Col I / [Annual kWh Sales] (Rnd to 6 dec.)	Col D + Col H + Col J

44,695,463 Annual kWh Sales (000)

Rate Impact Analysis

7% SUT Rate
6,960 Avg RS kWh / yr.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
			Class Average Rate w/SUT - $/kWh[1]											
	SPRC + Electric RRC w/o SUT ($/kWh)	**SPRC + Electric RRC w/ SUT ($/kWh)**	RS	RHS	RLM	GLP	LPL-S (0-749)	LPL-S (750-999)	LPL-S (1,000+)	LPL-P	HTS-S	HTS-HV	RS Average Annual Bill	Change in RS Average Annual Bill ($'s)
Current			0.179046	0.158883	0.168359	0.171625	0.151411	0.154350	0.137599	0.129715	0.120813	0.111963	1,246.16	
2009	0.000283	**0.000303**	0.179349	0.159186	0.168662	0.171928	0.151714	0.154653	0.137902	0.130018	0.121116	0.112266	1,248.28	2.12
2010	0.000375	**0.000401**	0.179447	0.159284	0.168760	0.172026	0.151812	0.154751	0.138000	0.130116	0.121214	0.112364	1,248.95	2.79
2011	0.000446	**0.000477**	0.179523	0.159360	0.168836	0.172102	0.151888	0.154827	0.138076	0.130192	0.121290	0.112440	1,249.48	3.32
2012	0.000463	**0.000495**	0.179541	0.159378	0.168854	0.172120	0.151906	0.154845	0.138094	0.130210	0.121308	0.112458	1,249.61	3.45
2013	0.000392	**0.000419**	0.179465	0.159302	0.168778	0.172044	0.151830	0.154769	0.138018	0.130134	0.121232	0.112382	1,249.08	2.92
	From Col K above	Col 1 * (1 + SUT Rate) Rnd 6	Current Class Avg Rate + Col 2 for Each Rate Class (Col 3 thru Col 12)										Col 3 * Avg RS kWh / yr.	Col 13 - Current RS Avg Annual Bill

	% Change from Current Class Average Rate w/SUT									
	RS	RHS	RLM	GLP	LPL-S (0-749)	LPL-S (750-999)	LPL-S (1,000+)	LPL-P	HTS-S	HTS-HV
2009	0.169%	0.191%	0.180%	0.177%	0.200%	0.196%	0.220%	0.234%	0.251%	0.271%
2010	0.224%	0.252%	0.238%	0.234%	0.265%	0.260%	0.291%	0.309%	0.332%	0.358%
2011	0.266%	0.300%	0.283%	0.278%	0.315%	0.309%	0.347%	0.368%	0.395%	0.426%
2012	0.276%	0.312%	0.294%	0.288%	0.327%	0.321%	0.360%	0.382%	0.410%	0.442%
2013	0.234%	0.264%	0.249%	0.244%	0.277%	0.271%	0.305%	0.323%	0.347%	0.374%

[1]All customers assumed to have BGS Supply

Place Holder

For

Cost Effectiveness Analysis

To be Filed At a Later Date

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY ELECTRIC CUSTOMERS

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Demand Response Program and Associated Cost Recovery Mechanism Pursuant to the BPU Order <u>I/M/O Demand Response Programs for the Period Beginning June 1, 2009 – Electric Distribution Company Programs</u>

BPU Docket No. EO08050326

Notice of Filing and Public Hearings For Proposed Demand Response Program and Associated Cost Recovery Mechanism

TAKE NOTICE that, on August 5, 2008 Public Service Electric and Gas Company ("Public Service", "PSE&G", "the Company") filed a Petition and supporting documentation with the New Jersey Board of Public Utilities ("Board", "BPU") in Docket Number EO08050326 seeking Board approval to implement and administer a PSE&G Demand Response Program ("Program") and to approve an associated cost recovery mechanism.

In its Order, the Board directed each of the State's electric distribution utilities to submit proposals for demand response programs to be implemented by June 1, 2009. PSE&G seeks Board approval to implement such a program to be made available to all customer classes and to attempt to achieve the electric load reduction goals as set forth in the Board's Order. Public Service proposes, through this regulated service, to target various customer classes in its Demand Response Program, specifically the residential segment; a small commercial segment and a large commercial/industrial segment.

PSE&G is requesting, for purposes of this program, that the Board grant approval of recovery of all program costs. PSE&G proposes to recover all Program costs via a separate component of the electric RGGI recovery charge (RRC) mechanism. The RRC would be reviewed and modified in an annual filing that PSE&G would make with the Board**.** Pursuant to the RGGI legislation, the Company requests that the carrying charge on its deferred balances for this Demand Response Program be set as PSE&G's overall weighted average cost of capital ("WACC") authorized by the Board in the most recent base rate case, together with the income tax effects. In addition, PSE&G requests that it earn a return on its net investment in the Program based on its WACC. Finally, for those sub-programs that it will nominate into PJM demand response programs, PSE&G proposes to share the payments it receives from PJM with customers via a credit to the RRC, subject to pre-determined guidelines. PSE&G also requests that all legacy Demand Response A/C Cycling program costs currently being recovered through the System Control Charge (SCC) be recovered through this new component of the electric RRC. On the date that the new RRC rate becomes effective, the SCC would be reset to $0.000000.

The proposed new charges for customers are as follows:

	Present	**Present** (Incl. Sales & Use Tax)	**Proposed**	**Proposed** (Incl. Sales & Use Tax)
Electric RGGI Recovery Charge Demand Response Programs ($ per kWh)	-	-	$0.000134	$0.000143
Electric System Control Charge ($ per kWh)	$0.000115	$0.000123	$0.000000	$0.000000

The effect of the proposed increase on typical residential electric bills, if approved by the Board, is illustrated below:

Residential Electric Service					
If Your Annual kWh Use Is:	And Your Monthly Summer kWh Use Is:	Then Your Present Monthly Summer Bill (1) Would Be:	And Your Proposed Monthly Summer Bill (2) Would Be:	Your Monthly Summer Bill Increase Would Be:	And Your Monthly Percent Increase Would Be:
1,800	170	$32.59	$32.59	$0.00	0.00%
3,600	360	66.30	66.31	0.01	0.02
6,960	722	132.20	132.21	0.01	0.01
7,800	803	147.69	147.70	0.01	0.01
12,000	1,250	233.13	233.16	0.03	0.01

(1) Based upon current Delivery Rates and Basic Generation Service Fixed Pricing (BGS-FP) charges in effect July 1, 2008 and assumes that the customer receives BGS-FP service from Public Service.
(2) Same as (1) except includes RGGI Recovery Charge.

Based upon this filing, a typical residential electric customer using 722 kilowatthours per summer month and 6,960 kilowatthours on an annual basis would see an increase in the annual bill from $1,246.16 to $1,246.28, or $0.12 or approximately 0.01%.

Any final rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of this filing may be modified and/or allocated by the Board in accordance with the provisions of *N.J.S.A.* 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the above described charges may increase or decrease based upon the Board's decision.

Copies of the Company's August 5**,** 2008 filing are available for review at the Company's Customer Service Centers and at the Board of Public Utilities at Two Gateway Center, Newark, New Jersey 07102.

The following dates, times and locations for public hearings have been scheduled on the above filing so that members of the public may present their views.

Date 1, 2008	Date 2, 2008	Date 3, 2008
Time 1	Time 2	Time 3
Location 1	Location 2	Location 3
Location 1 Overflow	Location 2 Overflow	Location 3 Overflow
Room1	Room 2	Room 3
Room 1 Overflow	Room 2 Overflow	Room 3 Overflow
Address 1	Address 2	Address 3
City 1, N.J. Zip 1	City 2, N.J. Zip 2	City 3, N.J. Zip 3

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 above hearings. Customers may file written comments with the Secretary of the Board of Public Utilities at Two Gateway Center, Newark, New Jersey 07102 ATTN: Kristi Izzo whether or not they attend the public hearings.

Frances I. Sundheim
Vice President and Corporate Rate Counsel

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Frances I. Sundheim
Vice President and Corporate Rate Counsel

Public Service Electric and Gas Company
80 Park Plaza - T8C, Newark, New Jersey 07102-4194
973-430-6928 fax: 973-648-0838
email: frances.sundheim@pseg.com

PSEG

August 5, 2008

In the Matter of the Petition of
Public Service Electric and Gas Company
for Approval of a Demand Response Program
and Associated Cost Recovery Mechanism
Pursuant to the BPU Order
I/M/O Demand Response Programs
for the Period Beginning June 1, 2009 –
Electric Distribution Company Programs

BPU Docket No. EO08050326

Clerks of Municipalities
County Executives,
Clerk of Board of Chosen Freeholders and
County Administrators
In the Company's Electric and Gas Service Area

Public Service Electric and Gas Company has filed a Petition with the Board of Public Utilities of the State of New Jersey requesting an increase in the charges for electric service. A copy of the Notice is enclosed for your information.

The Company is seeking Board of Public Utilities approval to provide and invest in a Demand Response Program in our service territory.

Any rate relief found by the Board to be just and reasonable may be allocated by the Board for consistency with the provisions of *N.J.S.A* 48:2-21, and for other good and legally sufficient reasons, to any class or classes of customers of the Company. Therefore, the average percentage increase in rates may increase or decrease based upon the Board's decision. The Board may choose to impose a greater portion of any increase on any class or classes of customers and may exclude from increase any class or classes.

Existing electric rates will remain in effect until new rates are approved by the Board of Public Utilities.

It is expected that the Board of Public Utilities will schedule hearings on the Company's Petition. Notice of such hearings will be given in accordance with such requirements as the Board may impose.

Very truly yours,

Attachment

NOTICE TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY ELECTRIC CUSTOMERS

In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Demand Response Program and Associated Cost Recovery Mechanism Pursuant to the BPU Order <u>I/M/O Demand Response Programs for the Period Beginning June 1, 2009 – Electric Distribution Company Programs</u>

BPU Docket No. EO08050326

TAKE NOTICE that, on August 5, 2008 Public Service Electric and Gas Company ("Public Service", "PSE&G", "the Company") filed a Petition and supporting documentation with the New Jersey Board of Public Utilities ("Board", "BPU") in Docket Number EO08050326 seeking Board approval to implement and administer a PSE&G Demand Response Program ("Program") and to approve an associated cost recovery mechanism.

In its Order, the Board directed each of the State's electric distribution utilities to submit proposals for demand response programs to be implemented by June 1, 2009. PSE&G seeks Board approval to implement such a program to be made available to all customer classes and to attempt to achieve the electric load reduction goals set forth in the Board's Order. Public Service proposes, through this regulated service, to target various customer classes in its Demand Response Program, specifically the residential segment; a small commercial segment and a large commercial/industrial segment.

PSE&G is requesting, for purposes of this program, that the Board grant approval of recovery of all program costs. PSE&G proposes to recover all Program costs via a separate component of the electric RGGI recovery charge (RRC) mechanism. The RRC would be reviewed and modified in an annual filing that PSE&G would make with the Board**.** Pursuant to the RGGI legislation, the Company requests that the carrying charge on its deferred balances for this Demand Response Program be set as PSE&G's overall weighted average cost of capital ("WACC") authorized by the Board in the most recent base rate case, together with the income tax effects. In addition, PSE&G requests that it earn a return on its net investment in the Program based on its WACC. Finally, for those sub-programs that it will nominate into PJM demand response programs, PSE&G proposes to share the payments it receives from PJM with customers via a credit to the RRC, subject to pre-determined guidelines. PSE&G also requests that all legacy Demand Response A/C Cycling program costs currently being recovered through the System Control Charge (SCC) be recovered through this new component of the electric RRC. On the date that the new RRC rate becomes effective, the SCC would be reset to $0.000000.

The proposed new charges for customers are as follows:

	Present	**Present** (Incl. Sales & Use Tax)	**Proposed**	**Proposed** (Incl. Sales & Use Tax)
Electric RGGI Recovery Charge Demand Response Programs ($ per kWh)	-	-	$0.000134	$0.000143
Electric System Control Charge ($ per kWh)	$0.000115	$0.000123	$0.000000	$0.000000

The effect of the proposed increase on typical residential electric bills, if approved by the Board, is illustrated below:

Residential Electric Service					
If Your Annual kWh Use Is:	And Your Monthly Summer kWh Use Is:	Then Your Present Monthly Summer Bill (1) Would Be:	And Your Proposed Monthly Summer Bill (2) Would Be:	Your Monthly Summer Bill Increase Would Be:	And Your Monthly Percent Increase Would Be:
1,800	170	$32.59	$32.59	$0.00	0.00%
3,600	360	66.30	66.31	0.01	0.02
6,960	722	132.20	132.21	0.01	0.01
7,800	803	147.69	147.70	0.01	0.01
12,000	1,250	233.13	233.16	0.03	0.01

(1) Based upon current Delivery Rates and Basic Generation Service Fixed Pricing (BGS-FP) charges in effect July 1, 2008 and assumes that the customer receives BGS-FP service from Public Service.
(2) Same as (1) except includes RGGI Recovery Charge.

Based upon this filing, a typical residential electric customer using 722 kilowatthours per summer month and 6,960 kilowatthours on an annual basis would see an increase in the annual bill from $1,246.16 to $1,246.28, or $0.12 or approximately 0.01%.

Any final rate adjustments with resulting changes in bill impacts found by the Board to be just and reasonable as the result of this filing may be modified and/or allocated by the Board in accordance with the provisions of *N.J.S.A.* 48:2-21 and for other good and legally sufficient reasons to any class or classes of customers of the Company. Therefore, the above described charges may increase or decrease based upon the Board's decision.

Copies of the Company's August 5**,** 2008 filing are available for review at the Company's Customer Service Centers and at the Board of Public Utilities at Two Gateway Center, Newark, New Jersey 07102.

Frances I. Sundheim
Vice President and Corporate Rate Counsel

PUBLIC SERVICE ELECTRIC AND GAS COMPANY