Agenda Date: 10/23/2012
Agenda Item: 2D

STATE OF NEW JERSEY

Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

ENERGY

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF	ORDER APPROVING STIPULATION BPU DOCKET NO. ER11080469 OAL DOCKET NO. PUC 09929-2011N
IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF CERTAIN ENERGY INFRASTRUCTURE INVESTMENTS AND APPROVAL OF COST RECOVERY FOR SUCH PROJECTS AND RELATED TARIFF MODIFICATIONS ASSOCIATED THEREWITH PURSUANT TO N.J.S.A. 48:2-21 and 48:2-21.1	BPU DOCKET NOS. EO09010054 and ER09110924 OAL DOCKET NO. PUC 03360-12
IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AN UPDATE TO THE COST RECOVERY MECHANISM ASSOCIATED WITH ITS CAPITAL ECONOMIC STIMULUS INFRASTRUCTURE INVESTMENT PROGRAM PURSUANT TO N.J.S.A. 48:2-21 and 48:2-21.1	BPU DOCKET NO. EO10110847 OAL DOCKET NO. PUC 03359-12
IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR FINAL RECONCILIATION OF INFRASTRUCTURE PROGRAM COSTS	BPU DOCKET NO. EO11110846 OAL DOCKET NO. PUC 03358-12
IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND ATLANTIC CITY ELECTRIC COMPANY'S REQUEST FOR DEFERRAL ACCOUNTING AUTHORITY FOR STORM DAMAGE RESTORATION COSTS	BPU DOCKET NOS. EO11090518 and GO11090519 OAL DOCKET NO. PUC 13934-12

Parties of Record:

Phillip J. Passanante, Esq. and **Nicholas W. Mattia** Jr., Esq. on behalf of Atlantic City Electric Company
Stefanie A. Brand, Esq., Director, New Jersey Division of Rate Counsel
Michael A. Gruin, Esq., (Stevens & Lee) on behalf of Wal-Mart Stores East LP and Sam's East Inc.

BY THE BOARD[1]:

Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, on August 5, 2011, Atlantic City Electric Company ('ACE" or "Company") filed a petition with the New Jersey Board of Public Utilities ("BPU" or "Board") seeking a $70.5 million (exclusive of Sales and Use Tax ("SUT")) increase in its base rates for electric service and an approximate $470,000 (excluding SUT) increase in the Company's Regulatory Asset Recovery Charge ("RARC"). The Company also sought to modify the mechanism by which a previously Board ordered amortization of an excess depreciation reserve is reflected in customer rates. In addition, the Company also requested other changes to its tariff.

The Company's filing was based on a test year of the twelve months ending December 31, 2011, with nine months of estimated data and three months of actual data. The petition was accompanied by exhibits and pre-filed testimony.

On August 18, 2011, the matter was transmitted to the Office of Administrative Law ("OAL") as a contested case, and was assigned to Administrative Law Judge ("ALJ") Irene Jones. On November 15, 2011, ALJ Jones issued a pre-hearing Order.

On August 19, 2011, Public Service Electric and Gas Company ("PSE&G") filed a motion for participant status in this matter. On October 27, 2011, the Company filed a response opposing grant of participant status to PSE&G. Subsequently, on November 4, 2011, PSE&G filed a reply. By Order dated November 16, 2011, ALJ Jones granted PSE&G participant status in this proceeding pursuant to N.J.A.C. 1:1-16.6.

On September 7, 2011, Wal-Mart Stores East, LP and Sam's East, Inc. (collectively, "Walmart") filed a motion to intervene in this matter. On December 6, 2011, ALJ Jones issued an Order that granted intervener status to Walmart.

By Order dated September 22, 2011, the Board issued an Order suspending the rates and charges.

On December 1, 2011, the Company submitted a letter motion requesting that the Board issue an Order to (1) bifurcate the Company's involvement in a joint petition with PSE&G filed with the Board on August 26, 2011 in Docket Nos. EO11090518 and GO11090519 that sought authorization to defer actual storm restoration costs related to the then-impending Hurricane Irene, and (2) transmit the ACE portion of the bifurcated joint petition, along with all the Company-related discovery and responses, to the OAL with a request to consolidate the matter

[1] Commissioner Holden did not participate in this matter.

with the base rate case. On December 15, 2011, after being advised by the New Jersey Division of Rate Counsel ("Rate Counsel") and PSE&G that they did not oppose the request, the Board granted the Company's letter petition.

On February 24, 2012, the Company updated its test year data to reflect twelve months of actual data which reflected a total requested increase in retail base rates of $90.6 million, exclusive of SUT and an additional increase of $170,000 (exclusive of SUT) in its RARC claim. On March 6, 2012, the Company filed workpapers supporting its updated revenue requirement projection that had been filed on February 24, 2012.

Public hearings were held on March 22, 2012, in Mays Landing, New Jersey. In addition, a supplemental public hearing was held on May 31, 2012, in Mays Landing, New Jersey. The purpose of the supplemental hearing was to rectify an inadvertent error in the original public hearing notice affecting a discreet class of street lighting customers. One individual appeared at the initial public hearing to inquire about the financial impact of the filing.

On March 23, 2012, ALJ Jones directed the parties to comment on the consolidation of ACE's Infrastructure Investment Program ("IIP") proceedings, - the IIP-1 initial filing (BPU Docket Nos. EO09010054 and ER09110924), the IIP surcharge adjustment filing (BPU Docket No. EO10110847), and the IIP-1 final reconciliation filing (BPU Docket No. EO11110846) - into the base rate case. By letter dated March 26, 2012, Rate Counsel advised ALJ Jones that it did not object to the consolidation of the IIP-1 dockets into the base rate case.

On April 25, 2012, Rate Counsel filed the direct testimony of five witnesses, and Walmart filed the direct testimony of one witness. On May 23, 2012, ACE filed its rebuttal testimony.

Evidentiary hearings for this matter, which included oral surrebuttal testimony on behalf of Rate Counsel, were held at the OAL on June 18, 19, 20, 21, 25, and 27, 2012. Initial briefs were filed on July 27, 2012, and reply briefs were filed on August 10, 2012.

After engaging in extensive settlement negotiations, on October 12, 2012, the Company, BPU Staff ("Staff"), Rate Counsel and Walmart (collectively, the "Stipulating Parties") executed a Stipulation of Settlement ("Stipulation").

<u>THE PROPOSED STIPULATION</u> [2]

The key provisions of the Stipulation are as follows:

2. **Revenue Requirements.** Based upon a test year ending December 31, 2011, as updated on February 24, 2012 for "12 + 0" test year actuals, Petitioner requested an annual increase in its current retail base rates for electric service of $90.268 million, exclusive of New Jersey SUT. The Company's requested base rate increase of $90.268 million included the impact on base rates of transferring the excess depreciation credit, as detailed in Paragraph 4 of the

[2] Although described at some length in this Order, should there be any conflict between this summary and the stipulation, the terms of the stipulation control, subject to the findings and conclusions in this Order.

Stipulation. The Stipulating Parties agree that an increase in base revenues of $44 million, exclusive of SUT is just and reasonable.

3. **Rate of Return, Return on Equity and Rate Base.** The Stipulating Parties agree that, for purposes of resolving the case, the Company shall have an authorized return on equity of 9.75 percent, with a corresponding overall rate of return of 8.05 percent, and that the common equity component of its total capitalization shall be deemed to be 48.33 percent. Additionally, for purposes of the Stipulation, the Stipulating Parties agree that the Company's filed rate base as reflected in the 12+0 updates is $921,847,000. This rate base amount does not reflect any particular ratemaking adjustment proposed by any party for incorporation into the overall revenue requirement calculation.

4. **Excess Depreciation Reserve.** In addition to the base revenue increase of $44 million provided for in the Stipulation, the Company proposed and the Stipulating Parties agree as follows. Pursuant to the Board Order dated May 26, 2005 in BPU Docket No. ER03020110, ACE has been amortizing approximately $131 million over 8.25 years related to an accumulated excess depreciation amount, which amount has been credited to customers through base rates since June 1, 2005. The estimated remaining balance to be refunded to customers as of October 30, 2012 is $13,229,697. In the instant Petition, the Company proposed to transfer this credit from base rates to a monthly credit to customers through a Rider to be established. The Stipulating Parties agree that this Rider shall be implemented with an effective date of the new base rates approved in this proceeding. The Stipulating Parties further agree that the Company cannot terminate this Rider until such time as the original credit amount of $131 million has been fully refunded to customers pursuant to the requirements of the Board's May 26, 2005 Order, and as further directed by the Board. The Company agrees to provide a compliance filing and status report to the Board and parties no later than 60 days prior to the expected termination date of the excess depreciation Rider, at which time Petitioner will report on how much of the excess depreciation reserve has been refunded to date, and how much remains to be refunded, and the expected date by which such refund will be completed.

   The Stipulating Parties agree that the compliance filing should be retained by the Board for its determination as to the appropriate date for the expiration of the Company's Rider. During the 60 day period, Staff and Rate Counsel shall have an opportunity to seek discovery and submit comments to the Board regarding the expiration of the Rider. If expiration of the Rider is unopposed, the Rider will terminate as proposed by the Company. If any Stipulating Party has a specific concern regarding the amount actually refunded to customers, such Stipulating Party can request that the Board take such action necessary to resolve the issue. At such time as when the Rider is terminated by the Board, the Company shall be permitted to establish a deferred account to capture any over/under credit balance that exists as of the date of such Rider termination, and the ratemaking associated with this item shall be addressed in the Company's next base rate filing.

5. **Depreciation.** The Company shall file a new depreciation study as part of its next base rate case filing.

6. **Hurricane Irene Costs.** The Stipulating Parties agree that the costs associated with Hurricane Irene of $7,690,760 shall be amortized over a three (3) year period commencing with the Board's approval and implementation of new rates hereunder. The unamortized balance will not be included in rate base.

7. **Regulatory Asset Recovery Charge ("RARC").** As part of the petition, the Company proposed to adjust the RARC by removing from the current RARC the costs associated with regulatory assets that have been fully amortized. The Company proposed to further adjust the RARC by adding seven additional regulatory assets, namely: (i) costs associated with payments related to the redemption of preferred stock completed in March 2011; (ii) administrative expenses related to the Long-term Capacity Agreement Pilot Program ("LCAPP"); (iii) costs related to PJM default assessment charges stemming from the Company's PJM obligations as a result of non-utility generation contracts; (iv) costs related to the recovery of additional taxes as a result of changes to the law regarding Medicare Part D; (v) costs related to the Affiliated Transaction and Management Audits BPU Docket No. EA07100794 that have occurred subsequent to those currently included in the RARC effective June 1, 2010; (vi) costs associated with outside consulting services retained by the Company to provide administrative support for a New Jersey Department of Transportation audit of certain utility relocation costs; and (vii) the reconciliation of an under-recovered balance associated with the monthly differences between RARC-related revenue and amortization expenses. For purposes of settlement, the Stipulating Parties agree that the total annual amount to be recovered through the RARC is $2,647,751.

   The Stipulating Parties agree that the RARC shall be continued as a rate recovery mechanism at least until the resolution of the Company's next filed base rate case. In the Company's next base rate case, any party shall be free to propose a change in the recovery mechanism for items currently being recovered through the RARC. For purpose of the Stipulation, the RARC shall be established as follows:

   (a) all items currently being recovered through the RARC shall continue to be recovered until fully amortized;
   (b) item i, above, shall be included in the RARC for recovery, based upon a 15 year amortization period;
   (c) items ii, and v, above, shall be included in the RARC for recovery. These costs will be offset by item vii, as corrected on Exhibit A. The net of items ii, v and vii (as corrected) shall be amortized over a four year period; and
   (d) items iii, iv and vi shall not be recovered through the RARC.

   Exhibit A attached to the Stipulation is the revised calculation of the RARC to be effective as of November 1, 2012.

8. **Cost of Service and Tariff Design.** The Stipulating Parties agree to implement new rates, based upon a $44 million increase in retail distribution base rate revenues, exclusive of SUT, for service rendered on and after November 1, 2012, or as soon thereafter as determined by the Board. In that regard, the Stipulating Parties agree that this increase in base revenues should be distributed in the following manner, and that additional modifications to the Company's tariffs should be implemented as set forth below:

(a) An allocation of the distribution revenue increase such that the percentage increase to Rate Schedule R (Residential), Rate Schedule SPL (Street and Private Lighting), and Rate Schedule CSL (Contributed Street Lighting) shall be 102.7% of the overall percentage distribution revenue increase of 16.8%. The Stipulating Parties further agree that the distribution revenue increase shall be allocated to Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, Transmission General Service and DDC (Direct Distribution Connection) such that the percentage increases to these rate schedules shall be 95.8% of the overall percentage distribution revenue increase of 16.8%.

(b) The customer charge for Rate Schedule R shall be increased by $0.27 to $3.00 (including SUT) from its current level of $2.73. The balance of the distribution rate increase will be recovered through the volumetric rates component. The rate block difference for volumetric winter rates for Rate Schedule R shall be reduced by 25%.

(c) The rate design for Rate Schedules MGS Secondary and MGS Primary shall be modified as follows:

(i) All customer charges shall be maintained at current levels.

(ii) The demand charge shall be modified such that it is based on total measured demand. The current rate design feature that allows the initial 3 kW of measured demand to be excluded from the charge shall be eliminated. The proposed demand charge will be designed to recover the same level of revenue as the current distribution demand charges. The remainder of the distribution revenue shall be recovered through the volumetric rate component.

(iii) The existing three tier declining block volumetric charges shall be replaced with a single, seasonally differentiated volumetric charge, which recovers the remaining portion of the distribution revenue. The seasonal rate differentiation shall be designed to maintain current seasonal to annual average rate relationships.

(iv) The "ceiling limit" rate design feature shall be eliminated.

(d) The existing Rate Schedule TGS (Transmission General Service) shall be split into two rate schedules: (1) -- Rate Schedule TGS – Transmission, and (2) Rate Schedule -- TGS Sub Transmission -- to recognize the different voltage levels for customers taking service on this rate schedule. Rate Schedule TGS - Transmission will be applicable to customers taking service at a voltage level at or above 69,000 volts (69 kV). The rate will be redesigned to a customer charge only. The distribution standby rate for customers taking service under this rate schedule is eliminated. Rate Schedule TGS Sub Transmission will be applicable to customers taking service at voltage levels of 23,000 volts (23 kV) or 34,000 volts (34 kV). The rate structure for this rate schedule shall remain a customer charge and demand charge.

(e) The Company can introduce two new experimental lighting offerings for Light Emitting Diode and induction lighting. Both offerings will be provided over a range of lamp sizes for both overhead and underground service configurations. The new offerings will be added to the existing light configuration currently included in Rate Schedules CSL and SPL.

(f) The Company can modify the terms and conditions of Rate Schedule SPL and Rate Schedule CSL to include a provision to allow customers to transition from the SPL to CSL Rate Schedule upon payment to the Company for the lights being transitioned. For lighting installations in service less than five years, the charge will be equivalent to the cost to install the lights under the provisions of Rate Schedule CSL. For installations in service five years or longer, the charge will be limited to the current labor costs to install a street light.

Attached as Exhibit B to the Stipulation are the tariff sheets necessary to produce the increase in annual operating revenues stipulated to in the Stipulation. Attached as Exhibit C to the Stipulation is a schedule setting forth the net effect on the rates set forth in Petitioner's tariff classifications. The overall annual average monthly bill impact for a typical residential customer using 1,000 kWh per month, inclusive of the impact of the excess depreciation Rider credit, will be an increase of $3.44 or 1.9 percent.

9. **Allowance for Funds Used During Construction ("AFUDC").** The Company shall, upon Board approval of the Stipulation, on a quarterly basis calculate its AFUDC rate pursuant to the Federal Energy Regulatory Commission ("FERC") formula. This FERC formula can be found at 18 C.F.R. Part 101, Electric Plant Instruction No. 3(a) (17) (2006).

10. **Infrastructure Investment Program ("IIP").** By Order dated April 28, 2009, the Board approved the Company's IIP in BPU Docket No. EO09010049. The IIP was comprised of 16 infrastructure projects with an estimated cost of approximately $27.6 million. The IIP has been concluded, and pursuant to the above referenced Board Order, the final reconciliation of the IIP was to be undertaken in the context of the Company's next filed base rate case. By Petition dated October 11, 2011 the Company filed its final reconciliation of the IIP with the Board and the parties to that proceeding. The Stipulating Parties have reviewed the reconciliation of the IIP as part of this proceeding, and

hereby agree that the Company has appropriately completed the projects contemplated by the Board's April 28, 2009 Order.

In reaching this conclusion the Stipulating Parties note that the Company received approximately $3,333,093 in stimulus awards under the American Recovery and Reinvestment Act of 2009 associated with several of the IIP projects, and that the net cost of the IIP was approximately $26.3 million, which is $1.3 million lower than the estimated program costs. Therefore the Company's IIP program should be determined to be concluded and the Company's rate base set forth herein shall include the $26.3 million of capital investments associated with the IIP. Coincident with the effective date of the distribution rate changes included in the Stipulation, the Infrastructure Investment Surcharge established as part of the IIP will be eliminated, and any over/under recovery will be applied to the NGC deferred balance. The Board's docket in the IIP matter shall be deemed completed and closed.

11. **IIP-2.** As part of the Stipulation, the Company agrees to withdraw its IIP-2 Petition currently pending before Board, and Commissioner Nicholas Asselta as the designated Hearing Officer, in Docket No. EO11100650. Upon approval of the Stipulation by the Board, the Company will submit a letter to the Board withdrawing its petition in the IIP-2 matter. In the interim, the Stipulating Parties agree to stay the procedural schedule in the IIP-2 matter, which currently requires Initial Briefs to be filed on October 22, 2012. By withdrawing the IIP-2 petition at this time, ACE will not be precluded in the future from filing a new petition seeking infrastructure cost recovery relief from the Board similar to that requested in the IIP-2 matter.

13. **Consolidated Tax Adjustment.** The Company and Rate Counsel agree that the Board should, on its own motion, establish a generic proceeding to review the CTA issue and determine what modifications, if any, are appropriate to the Board's current CTA policy and calculation methodology.

14. **Customer Service Improvement Plan and Reliability Improvement Plan.** As part of Phase 2 of Petitioner's 2009 base rate case (Order Approving Stipulation dated May 16, 2011, BPU Docket No. ER09080664), the parties to that proceeding proposed a Phase 2 Stipulation to the Board, which included a Customer Service Improvement Plan ("CSIP") and a Reliability Improvement Plan ("RIP"). The Board, by Order dated May 16, 2011, adopted the Phase 2 Stipulation in its entirety (the "Phase 2 Order"). The CSIP, which was developed to address concerns raised by the parties with respect to customer service issues, including customer complaints, and the RIP, whereby the Company committed to spend an additional $40 million on reliability-related infrastructure and other activities, were designed to be implemented over a five year period commencing as of the date of the Board's Phase 2 Order. By the end of that five year period, i.e., May 2016, the Company is expected to achieve certain identified improvement metrics in accordance with the metrics incorporated in the Stipulation that was attached to the Phase 2 Order. As provided for in the Phase 2 Order, the Company provided the Board and the parties in that matter annual reports on each respective plan's progress. For

the RIP, the initial report was filed on May 31, 2012, as part of the Company's Annual System Performance Report. The initial report for the CSIP was filed on or by August 30, 2012.

The Stipulating Parties are committed to developing procedures that will result in improved customer service and reliability for ACE's customers. To that end, the Stipulating Parties agree that following the annual filing of the RIP and CSIP, representatives from Staff, the Company and Rate Counsel will engage in quarterly informal consultation with each other to determine if the RIP and/or the CSIP are performing as anticipated, and to discuss additional improvements that can be considered. It is not the intention of the Stipulating Parties for these informal consultations to alter the terms and conditions of the Board approved RIP or CSIP, but rather to allow them to cooperatively monitor the progress that the Company has committed to in these areas, and discuss alternative options should additional progress be deemed necessary and achievable.

By letter dated October 12, 2012, PSE&G stated that it has no objection to the settlement.

On October 17, 2012, ALJ Jones issued her Initial Decision in this proceeding finding that:

1. The Signatory Parties have voluntarily agreed to the settlements as evidenced by the signatures of the signatory Parties or their representatives.

2. The settlements fully dispose of all issues in controversy and are consistent with law.

No exceptions to the Initial Decision were received.

DISCUSSION AND FINDINGS

In evaluating a proposed settlement, the Board must review the record, balance the interests of the ratepayers and the shareholders, and determine whether the settlement represents a reasonable disposition of the issues that will enable the company to provide its customers in this State with safe, adequate and proper service at just and reasonable rates. In re Petition of Pub. Serv. Elec. & Gas, 304 N.J. Super. 247 (App. Div.), cert. denied, 152 N.J. 12 (1997). The Board recognizes that the parties worked diligently to negotiate a compromise that attempts to meet the needs of as many stakeholders as possible. The Board further recognizes that the Stipulation represents a balanced solution considering the many complex issues that were addressed during the proceeding. Therefore, based on the Board's review and consideration of the record in this proceeding including the Stipulation and Initial Decision, the petition and testimony, the Board **HEREBY FINDS** the Initial Decision and the Stipulation to be reasonable, in the public interest and in accordance with the law. Accordingly, the Board **HEREBY ADOPTS** the attached Initial Decision and the Stipulation in their entirety, and **HEREBY INCORPORATES** their terms and conditions as though fully set forth herein.

The Board **NOTES** that BPU Docket Nos. EO11090518 and GO11090519 remain open with respect to PSE&G's request for deferred accounting treatment for certain storm-related costs.

The Company is **HEREBY DIRECTED** to file a letter withdrawing its IIP-2 Petition within five (5) days of the date of service of this Order so that BPU Docket No. EO11100650 may be closed.

In accordance with N.J.S.A. 48:2-40, the rates approved by this Order will become effective on the later of November 1, 2012 or the date of service of this Order. As a result of these changes, the overall annual average monthly bill impact for a typical residential customer using 1,000 kWh per month, inclusive of the impact of the excess depreciation Rider credit will be an increase of $3.44 or 1.9 percent.

The Company is **HEREBY DIRECTED** to file the appropriate tariff pages that conform to the terms and conditions of this Order within five (5) business days from the date of service of this Order.

The Company's base rates will remain subject to audit by the Board. This Decision and Order shall not preclude the Board from taking any actions deemed to be appropriate as a result of any Board audit.

DATED: 10/23/12

BOARD OF PUBLIC UTILITIES
BY:

ROBERT M. HANNA
PRESIDENT

JEANNE M. FOX
COMMISSIONER

JOSEPH L. FIORDALISO
COMMISSIONER

NICHOLAS ASSELTA
COMMISSIONER

ATTEST:

KRISTI IZZO
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469

BOARD OF PUBLIC UTILITIES		
Kristi Izzo, Secretary Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Jerome May Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Mark Beyer Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350
Alice Bator Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Sheila DeLucia Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Naji Ugoji Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350
Robert Schultheis Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Henry Rich Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Andrea Reid Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350
Eleana Lihan Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Scott Sumliner Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Beverly Tyndell Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350
Christine Lin Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Jackie O'Grady Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350	Jacqueline Galka Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350
Robert Wojciak Board of Public Utilities 44 S. Clinton Avenue, 9th Floor P.O. Box 350 Trenton, NJ 08625-0350		
DIVISION OF RATE COUNSEL		
Stefanie A. Brand, Esq. Division of Rate Counsel 31 Clinton Street, 11th Floor P.O. Box 46005 Newark, NJ 07101	Ami Morita, Esq. Division of Rate Counsel 31 Clinton Street, 11th Floor P.O. Box 46005 Newark, NJ 07101	Diane Schulze, Esq. Division of Rate Counsel 31 Clinton Street, 11th Floor P.O. Box 46005 Newark, NJ 07101
Brian Weeks, Esq. Division of Rate Counsel 31 Clinton Street, 11th Floor P.O. Box 46005 Newark, NJ 07101	James Glassen, Esq. Division of Rate Counsel 31 Clinton Street, 11th Floor P.O. Box 46005 Newark, NJ 07101	Lisa Gurkas Division of Rate Counsel 31 Clinton Street, 11th Floor P.O. Box 46005 Newark, NJ 07101

DEPARTMENT OF LAW & PUBLIC SAFETY		
Caroline Vachier, DAG Division of Law 124 Halsey Street, P.O. Box 45029 Newark, NJ 07101	Babette Tenzer, DAG Division of Law 124 Halsey Street, P.O. Box 45029 Newark, NJ 07101	Alex Moreau, DAG Division of Law 124 Halsey Street, P.O. Box 45029 Newark, NJ 07101
David Wand, DAG Division of Law 124 Halsey Street P.O. Box 45029 Newark, NJ 07101		
ACE		
Philip Passanante, Esq. Atlantic City Electric Company 500 N. Wakefield Drive P.O. Box 6066 Newark, DE 19714-6066	Roger Pedersen, Manager Regulatory Affairs, External Issues & Compliance Atlantic City Electric Company 5100 Harding Highway Mays Landing, NJ 08330	Nicholas W. Mattia, Jr., Esq. Dickstein Shapiro LLP 1825 Eye Street NW Washington, DC 2006-5403
PSE&G		
Martin C. Rothfelder, Esq. PSEG Services Corporation 80 Park Plaza, T5G P.O. Box 570 Newark, NJ 07102		
Walmart		
Linda R. Rivers, Esq. Stevens & Lee, P.C. 111 N. Sixth Street Reading, PA 19603-0679	Michael A. Gruin, Esq. Stevens & Lee, P.C. 17 N. 2nd Street, 16th Floor Reading, PA 17101	

State of New Jersey
OFFICE OF ADMINISTRATIVE LAW

INITIAL DECISION
SETTLEMENT
(CONSOLIDATED)

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO <u>N.J.S.A.</u> 48a:2-21 AND <u>N.J.S.A.</u> 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF.

OAL DKT. NO. PUC 09929-11
AGENCY DKT. NO. ER11080469

OAL DKT. NO. PUC 03358-12
AGENCY DKT. NO. EO10110846

OAL DKT. NO. PUC 03359-12
AGENCY DKT. NO. EO10110847

OAL DKT. NO. PUC 03360-12
AGENCY DKT. NO. EO09010049

OAL DKT. NO. PUC 03360-12
AGENCY DKT. NOS. EO09010049 and EO9010054

OAL DKT. NO. PUC 13934-12
AGENCY DKT. NOS. EO11090518 and GO11090519

Philip J. Passanante, Esq., Associate General Counsel, **Peter E. Meier**, Vice President, Legal Services, and **Nicholas W. Mattia, Jr.**, Esq., on behalf of Petitioner (Dickstein Shapiro, attorneys)

Stephanie A. Brand, Esq., **Paul Flanagan**, Esq., **Ami Morita**, Esq. and **Diane Shultz**, Esq., and **Brian Weeks**, Esq., on behalf of the Division of Rate Counsel (Stefanie A. Brand, Director)

T. David Wang and **Alex Moreau**, Deputy Attorney Generals, for the Staff of the Board of Public Utilities (Jeffery S. Chiesa, Attorney General of New Jersey, attorney)

Martin C. Rothfelder, Esq., Associate General Regulatory Counsel, for Public Service Electric & Gas

Michael A. Gruin, Esq. and **Linda R. Evers**, Esq., on behalf of Wal-Mart Stores East LP and Sam's East Inc.

Record Closed: October 12, 2012 Decided: October 17, 2012

BEFORE **IRENE JONES**, ALJ:

On or about August 5, 2011, petitioner, Atlantic City Electric Company, ("Petitioner" or "Company") filed a Verified Petition with the State Board of Public Utilities seeking to increase its base rates for electric service by approximately $51.6 million, exclusive of New Jersey sales and Use Tax ("SUT").

On or about August 23, 2011, the Board transmitted the matter to the Office of Administrative Law for hearing as a contested case pursuant to N.J.S.A. 52:14B-1 to 15 and N.J.S.A. 52:14F-1 to 13. A prehearing conference was held on October 19, 2011 wherein a procedural schedule was established. Present at the prehearing conference was the Company, the Board Staff, the Division of Rate Counsel, Public Service Electric & Gas Company, Wal-Mart and Sam's East.

On February 24, 2012 petitioner updated its filing which increased its proposed increase to approximately $90.6 million, exclusive of SUT. On March 2, 2010, Intevenor status was granted to Wal-Mart and Sam's East, (collectively, "Wal-Mart"). PSE&G was granted participant status. Pursuant to the Prehearing Order, public hearings were held in the Company's service territory on March 22 and May 31, 2012.

Evidentiary hearings were held on June 18, 19, 20, 21, 25 and 27, 2012. The parties exchanged extensive discovery and engaged in numerous discovery and settlement conferences. After the close of the testimonial portion of the hearings, the parties filed extensive briefs. Thereafter, the parties engaged in settlement discussions which resulted in the Stipulation of Settlement that is attached to this Initial Decision. On October 12, 2012, the parties filed a Stipulation of Settlement with the undersigned.

Pursuant to the terms of the attached stipulation, the parties have agreed to an increase in base rates of approximately $44 million. The parties further agree that the $44 million increase will be distributed to the rate classes as set forth in the attached Stipulation of Settlement. The attached Stipulation of Settlement also sets forth the parties agreement on issues relating to the Rate Base and Return on Equity, Depreciation and Excess Depreciation Reserve; Consolidated Taxes, Post Test Year Additions, Supplemental Employee Retirement Plan, Regulatory Assets Recovery Charges, Hurricane Irene Costs, Cost of Service and Tariff Design, AFUDC issues, the Company's Infrastructure Investment Program and its Customer Service Improvement and Reliability Improvement Plans as well as other issues as set forth in the Stipulation of Settlement.

I have reviewed the record and the terms of the Stipulation of Settlement and I **FIND:**

1. The parties have voluntarily agreed to the settlement as evidenced by their signatures or the signatures of their representatives.
2. The settlement fully disposes of all issues in controversy and is consistent with the law.

Therefore, it is **ORDERED** that the parties comply with the settlement terms and that these proceedings be and are hereby **CONCLUDED**.

I hereby **FILE** my initial decision with the **BOARD OF PUBLIC UTILITIES** for consideration.

This recommended decision may be adopted, modified or rejected by the **BOARD OF PUBLIC UTILITIES,** which by law is authorized to make a final decision in this matter. If the Board of Public Utilities does not adopt, modify or reject this decision within forty-five days and unless such time limit is otherwise extended, this recommended decision shall become a final decision in accordance with N.J.S.A. 52:14B-10.

October 17, 2012
DATE

Irene Jones
IRENE JONES, ALJ

Date Received at Agency:

Date Mailed to Parties:

sej/jb

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO *N.J.S.A.* 48:2-21 AND *N.J.S.A.* 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF	**STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU DOCKET NO. ER11080469 OAL DOCKET NO. PUC 09929-2011N**
IN THE MATTER OF THE PROCEEDING FOR INFRASTRUCTURE INVESTMENT AND A COST RECOVERY MECHANISM FOR ALL GAS AND ELECTRIC UTILITIES	**BPU DOCKET NO. EO09010049**
IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF CERTAIN ENERGY INFRASTRUCTURE INVESTMENTS AND APPROVAL OF COST RECOVERY FOR SUCH PROJECTS AND RELATED TARIFF MODIFICATIONS ASSOCIATED THEREWITH PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1	**BPU DOCKET NO. EO09010054**
IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR THE APPROVAL OF AN UPDATE TO THE COST RECOVERY MECHANISM ASSOCIATED WITH ITS CAPITAL ECONOMIC STIMULUS INFRASTRUCTURE INVESTMENT PROGRAM PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 (ADJUSTMENT TO ITS TARIFF TO BE EFFECTIVE JANUARY 1, 2011)	**BPU DOCKET NO. EO10110847**
IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S FINAL RECONCILIATION OF INFRASTRUCTURE PROGRAM PROJECTS AND COSTS	**BPU DOCKET NO. EO11110846**

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO *N.J.S.A.* 48:2-21 AND *N.J.S.A.* 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF	**STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU DOCKET NO. ER11080469 OAL DOCKET NO. PUC 09929-2011N**
IN THE MATTER OF THE PROCEEDING FOR INFRASTRUCTURE INVESTMENT AND A COST RECOVERY MECHANISM FOR ALL GAS AND ELECTRIC UTILITIES	**BPU DOCKET NO. EO09010049**
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IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR THE APPROVAL OF AN UPDATE TO THE COST RECOVERY MECHANISM ASSOCIATED WITH ITS CAPITAL ECONOMIC STIMULUS INFRASTRUCTURE INVESTMENT PROGRAM PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 (ADJUSTMENT TO ITS TARIFF TO BE EFFECTIVE JANUARY 1, 2011)	**BPU DOCKET NO. EO10110847**
IN THE MATTER OF ATLANTIC CITY ELECTRIC COMPANY'S FINAL RECONCILIATION OF INFRASTRUCTURE PROGRAM PROJECTS AND COSTS	**BPU DOCKET NO. EO11110846**

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND ATLANTIC CITY ELECTRIC COMPANY'S REQUEST FOR DEFERRAL ACCOUNTING AUTHORITY FOR STORM DAMAGE RESTORATION COSTS	BPU DOCKET NOS. EO11090518 and GO11090519 STIPULATION OF SETTLEMENT

APPEARANCES:

Philip J. Passanante, Esq., Associate General Counsel, Peter E. Meier, Vice President, Legal Services, and Nicholas W. Mattia, Jr., Esq. (Dickstein Shapiro, LLP), on behalf of Petitioner

Stefanie A. Brand, Esq., Paul Flanagan, Esq., Ami Morita, Esq. Diane Schulze, Esq., James W. Glassen, Esq., and Brian Weeks, Esq. (Stefanie A. Brand, Director, Division of Rate Counsel), on behalf of the Division of Rate Counsel

T. David Wand, Esq., Deputy Attorney General and Alex Moreau, Esquire, Deputy Attorney General (Jeffrey S. Chiesa, Attorney General of New Jersey) on behalf of the Staff of the Board of Public Utilities

Michael A. Gruin, Esq. and Linda R. Evers, Esq. (Stevens & Lee) on behalf of Wal-Mart Stores East LP and Sam's East Inc.

TO THE HONORABLE BOARD OF PUBLIC UTILITIES:

This Stipulation of Settlement (the "Stipulation") is hereby made and executed as of this 12th day of October, 2012, by and among Atlantic City Electric Company ("ACE", "Petitioner" or the "Company"), the Staff of the Board of Public Utilities ("Staff"), the New Jersey Division of Rate Counsel ("Rate Counsel") and Wal-Mart Stores East, LP and Sam's East Inc. (jointly referred to as "Wal-Mart"), each a "Stipulating Party", and collectively, the "Stipulating Parties", in settlement of all factual and legal issues, arising from the above captioned matters. Petitioner is a corporation organized and existing under the laws of the State of New Jersey and is subject to the jurisdiction of the Board. Petitioner has its principal offices at 500 North Wakefield Drive, Newark, Delaware 19702 and maintains a regional office at 5100

Harding Highway, Mays Landing, New Jersey 08330. Petitioner serves approximately 547,000 customers in 8 counties located in southern New Jersey.

PROCEDURAL HISTORY

On August 5, 2011, ACE submitted a Petition (the "Petition") to the Board of Public Utilities (the "Board" or the "BPU"), seeking an increase in the Company's base rates of approximately $70.5 million, excluding New Jersey Sales and Use Tax ("SUT"), as well as other related matters. On August 18, 2011, the Board transmitted the Petition to the New Jersey Office of Administrative Law ("OAL") as a contested case. The OAL assigned the Honorable Irene Jones, Administrative Law Judge ("ALJ"), to preside over the matter. A Prehearing Order was entered by ALJ Jones on November 15, 2011 (the "Prehearing Order"). By Order dated December 6, 2011, ALJ Jones granted a Motion to Intervene filed by Wal-Mart. Additionally, by Order dated November 16, 2011, ALJ Jones entered an Order Granting Participant Status to Public Service Electric and Gas Company pursuant to N.J.A.C. 1:1-16.6. On February 24, 2012, the Company filed its 2011 update to the Petition (through December 31, 2011), which had the effect of increasing the requested base rate increase to approximately $90.268 million, exclusive of SUT. Further, by Order of the Board the following matters have been consolidated with the Petition for final resolution. They are BPU Docket Nos. EO09010049, EO09010054, EO10110847 and EO11110846, each of which relate to the Company's initial Infrastructure Investment Program. Additionally, by Board Order dated December 15, 2011 the Company's request for deferred accounting treatment for certain of the costs associated with Hurricane Irene, bearing BPU Docket Nos. EO11090518 and GO11090519, was also consolidated with the Petition.

Public hearings were duly noticed and held at 3:30 P.M. and 5:30 P.M. on Thursday, March 22, 2012, in Mays Landing, New Jersey. The public hearing was presided over by ALJ W. Todd Miller. One individual appeared at the initial public hearing to inquire about the financial impact of the filing. That individual indicated on the record, after consultation with ACE representatives, that her question was satisfactorily answered. An additional set of public hearings was held on Thursday, May 31, 2012 at 3:30 P.M. and 5:30 P.M. before Commissioner Nicholas Asselta at the Mays Landing Branch of the Atlantic County Library. Evidentiary hearings were conducted before ALJ Irene Jones at the Office of Administrative Law in Newark, New Jersey on June 18, 19, 20, 21, 25 and 27, 2012. Following those hearings, Initial Briefs were filed by the Stipulating Parties, and by Participant PSE&G, on July, 27, 2012, and Reply Briefs were filed by the Company and Rate Counsel on August 10, 2012. Subsequent thereto, the Stipulating Parties have engaged in settlement discussions, which discussions have resulted in this Stipulation ("Settlement") by and among the Stipulating Parties. The Stipulating Parties agree to the following resolution of the issues to be considered in this matter, and hereby stipulate as follows:

SETTLEMENT TERMS AND CONDITIONS

1. Structure of Settlement. The Stipulating Parties acknowledge and agree that the terms of this Settlement, in their entirety, represent a full and fair conclusion with respect to the issues to be resolved in this proceeding. As noted herein, a number of issues have been specifically agreed upon, the details of which are set forth below. Among the Stipulating Parties, any "Issue(s) to be resolved" identified in the Prehearing Order that is/are not specifically addressed herein is/are deemed to be resolved by the Stipulating Parties for purposes of this Stipulation. Additionally, the Stipulating Parties have agreed to reserve certain issues identified below for resolution as part of a subsequent proceeding to be initiated either by the Board or as part of the Company's next filed base rate request. The Stipulating Parties agree that this Settlement is deemed to resolve, for purposes of this case, all issues considered at trial and during settlement discussions, including but not limited to consideration of a Consolidated Tax Adjustment ("CTA"). In addition, the Stipulating Parties have considered Post-Test Year Additions, the Company's Supplemental Employee Retirement Plan, Plant Held for Future Use, the Company's Incentive Compensation Plan, as well as other elements of the Company's rate request not specifically identified herein. By the non-specific nature of this Stipulation, the Stipulating Parties do not necessarily agree to any individual revenue component(s), or inclusion or non-inclusion, whether in whole or in part, in this Stipulation of any specific revenue related issue, except those specifically identified below, which may be encompassed in the revenue requirement agreed to herein.

2. Revenue Requirements. Based upon a test year ending December 31, 2011, as updated on February 24, 2012 for "12 + 0" test year actuals, Petitioner requested an annual increase in its current retail base rates for electric service of $90.268 million, exclusive of New Jersey SUT. The Company's requested base rate increase of $90.268 million included the impact on base rates of transferring the excess depreciation credit, as detailed in Paragraph 4 below. The Stipulating Parties agree that an increase in base revenues of $44 million, exclusive of SUT is just and reasonable.

3. Rate of Return, Return on Equity and Rate Base. The Stipulating Parties agree that, for purposes of resolving this case, the Company shall have an authorized return on equity of 9.75 percent, with a corresponding overall rate of return of 8.05 percent, and that the common equity component of its total capitalization shall be deemed to be 48.33 percent. Additionally, for purposes of this Stipulation, the Stipulating Parties agree that the Company's filed rate base as reflected in the 12+0 updates is $921,847,000. This rate base amount does not reflect any particular ratemaking adjustment proposed by any Stipulating Party for incorporation into the overall revenue requirement calculation.

4. Excess Depreciation Reserve. In addition to the base revenue increase of $44 million provided for herein, the Company proposed and the Stipulating Parties agree as follows. Pursuant to the Board Order dated May 26, 2005 in BPU Docket No. ER03020110, ACE has been amortizing approximately $131 million over 8.25 years related to an accumulated excess depreciation amount, which amount has been credited to customers through base rates since June 1, 2005. The estimated remaining balance to be refunded to customers as of October 30, 2012 is $13,229,697. In the instant Petition, the Company proposed to transfer this credit from base rates to a monthly credit to customers through a Rider to be established. The Stipulating Parties agree that this Rider shall be implemented with an effective date of the new base rates approved in this proceeding. The Stipulating Parties further agree that the Company cannot terminate this Rider until such time as the original credit amount of $131 million has been fully refunded to customers pursuant to the requirements of the Board's May 26, 2005 Order, and as further directed by the Board. The Company agrees to provide a compliance filing and status report to the Board and the Stipulating Parties no later than 60 days prior to the expected termination date of the excess depreciation Rider, at which time Petitioner will report (i) how much of the excess depreciation reserve has been refunded to date; (ii) how much of the excess depreciation reserves remains to be refunded; and (iii) the expected date by which such refund will be completed.

The Stipulating Parties agree that the compliance filing should be retained by the Board for its determination as to the appropriate date for the expiration of the Company's Rider. Staff and Rate Counsel shall have an opportunity to seek discovery and submit comments to the

Board regarding the expiration of the Rider. If expiration of the Rider is unopposed, the Rider will terminate as proposed by the Company. If any Stipulating Party has a specific concern regarding the amount actually refunded to customers, such Stipulating Party can request that the Board take such action necessary to resolve the issue. At such time as when the Rider is terminated, the Company shall be permitted to establish a deferred account to capture any over/under credit balance that exists as of the date of such Rider termination, and the ratemaking associated with this item shall be addressed in the Company's next base rate filing.

5. Depreciation. The Company shall file a new depreciation study as part of its next base rate case filing.

6. Hurricane Irene Costs. The Stipulating Parties agree that the costs associated with Hurricane Irene of $7,690,760 shall be amortized over a three (3) year period commencing with the Board's approval and implementation of new rates hereunder. The unamortized balance will not be included in rate base.

7. Regulatory Asset Recovery Charge ("RARC"). As part of the Petition, the Company proposed to adjust the RARC by removing from the current RARC the costs associated with regulatory assets that have been fully amortized. The Company proposed to further adjust the RARC by adding seven additional regulatory assets, namely: (i) costs associated with payments related to the redemption of preferred stock completed in March 2011; (ii) administrative expenses related to the Long-term Capacity Agreement Pilot Program ("LCAPP"); (iii) costs related to PJM default assessment charges stemming from the Company's PJM obligations as a result of non-utility generation contracts; (iv) costs related to the recovery of additional taxes as a result of changes to the law regarding Medicare Part D; (v) costs related to the Affiliated Transaction and Management Audits BPU Docket No. EA07100794 that have occurred subsequent to those currently included in the RARC effective June 1, 2010; (vi) costs associated with outside consulting services retained by the Company to provide administrative support for a New Jersey Department of Transportation audit of certain utility relocation costs; and (vii) the reconciliation of an over-recovered balance associated with the monthly differences between RARC-related revenue and amortization expenses. For purposes of settlement, the Stipulating Parties agree that the total annual amount to be recovered through the RARC is $2,647,751.

In furtherance of settlement in this matter, the Stipulating Parties agree that the RARC shall be continued as a rate recovery mechanism at least until the resolution of the Company's next filed base rate case. In the Company's next base rate case, any Stipulating Party shall be free to propose a change in the recovery mechanism for items currently being recovered through the RARC. For purpose of this Stipulation, the RARC shall be established as follows:

(a) all items currently being recovered through the RARC shall continue to be recovered until fully amortized;

(b) item i, above, shall be included in the RARC for recovery, based upon a 15 year amortization period;

(c) items ii, and v, above, shall be included in the RARC for recovery. These costs will be offset by item vii, as corrected on Exhibit A. The net of items ii, v and vii (as corrected) shall be amortized over a four year period; and

(d) the Stipulating Parties agree that items iii, iv and vi shall not be recovered through the RARC.

Exhibit A attached is the revised calculation of the RARC to be effective as of November 1, 2012.

8. **Cost of Service and Tariff Design.** The Stipulating Parties agree to implement new rates, based upon a $44 million increase in retail distribution base rate revenues, exclusive of SUT, for service rendered on and after November 1, 2012, or as soon thereafter as determined by the Board. In that regard, the Stipulating Parties agree that this increase in base revenues should be distributed in the following manner, and that additional modifications to the Company's tariffs should be implemented as set forth below:

(a) The Stipulating Parties agree to an allocation of the distribution revenue increase such that the percentage increase to Rate Schedule R (Residential), Rate Schedule SPL (Street and Private Lighting), and Rate Schedule CSL (Contributed Street Lighting) shall be 102.7% of the overall percentage distribution revenue increase of 16.8%. The Stipulating Parties further agree that the distribution revenue increase shall be allocated to Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, Transmission General Service and DDC (Direct Distribution Connection) such that the percentage increases to these rate schedules shall be 95.8% of the overall percentage distribution revenue increase of 16.8%.

(b) The Stipulating Parties agree that the customer charge for Rate Schedule R shall be increased by $0.27 to $3.00 (including SUT) from its current level of $2.73. The balance of the distribution rate increase will be recovered through the volumetric rates component. The Stipulating Parties further agree that the rate block difference for volumetric winter rates for Rate Schedule R shall be reduced by 25%.

(c) The Stipulating Parties agree that the rate design for Rate Schedules MGS Secondary and MGS Primary shall be modified as follows:

(i) All customer charges shall be maintained at current levels.

(ii) The demand charge shall be modified such that it is based on total measured demand. The current rate design feature that allows the initial 3 kW of measured demand to be excluded from the charge shall be eliminated. The proposed demand charge will be designed to recover the same level of revenue as the current distribution demand charges. The remainder of the distribution revenue shall be recovered through the volumetric rate component.

(iii) The existing three tier declining block volumetric charges shall be replaced with a single, seasonally differentiated volumetric charge, which recovers the remaining portion of the distribution revenue. The seasonal rate differentiation shall be designed to maintain current seasonal to annual average rate relationships.

(iv) The "ceiling limit" rate design feature shall be eliminated.

(d) The existing Rate Schedule TGS (Transmission General Service) shall be split into two rate schedules: (1) -- Rate Schedule TGS – Transmission, and (2) Rate Schedule -- TGS Sub Transmission -- to recognize the different voltage levels for customers taking service on this rate schedule. Rate Schedule TGS - Transmission will be applicable to customers taking service at a voltage level at or above 69,000 volts (69 kV). The rate will be redesigned to a customer charge only. The distribution standby rate for customers taking service under this rate schedule is eliminated. Rate Schedule TGS Sub Transmission will be applicable to customers taking service at voltage levels of 23,000 volts (23 kV) or 34,000 volts (34 kV). The rate structure for this rate schedule shall remain a customer charge and demand charge.

(e) The Stipulating Parties agree that the Company can introduce two new experimental lighting offerings for Light Emitting Diode and induction lighting. Both offerings will be provided over a range of lamp sizes for both overhead and underground service configurations. The new offerings will be added to the existing light configuration currently included in Rate Schedules CSL and SPL.

(f) The Stipulating Parties agree that the Company can modify the terms and conditions of Rate Schedule SPL and Rate Schedule CSL to include a provision to allow customers to transition from the SPL to CSL Rate Schedule upon payment to the Company for the lights being transitioned. For lighting installations in service less than five years, the charge will be equivalent to the cost to install the lights under the provisions of Rate Schedule CSL. For installations in service five years or longer, the charge will be limited to the current labor costs to install a street light.

Attached as **Exhibit B** are the tariff sheets necessary to produce the increase in annual operating revenues stipulated to herein. Attached as **Exhibit C** is a schedule setting forth the net effect on the rates set forth in Petitioner's tariff classifications. The overall annual average monthly impact of this rate change on the total bill for a typical residential customer using 1000 kWh per month, inclusive of the impact of the excess depreciation Rider credit, is $3.44 or 1.9 percent.

9. Allowance for Funds Used During Construction ("AFUDC"). The Stipulating Parties agree that the Company shall, upon Board approval of this Stipulation, on a quarterly basis calculate its AFUDC rate pursuant to the Federal Energy Regulatory Commission ("FERC") formula. This FERC formula can be found at 18 C.F.R. Part 101, Electric Plant Instruction No. 3.A.(17).

10. Infrastructure Investment Program ("IIP"). By Order dated April 28, 2009, the Board approved the Company's IIP in NJBPU Docket No. EO09010049. The IIP was comprised of 16 infrastructure projects with an estimated cost of approximately $27.6 million. The IIP has been concluded, and pursuant to the above referenced Board Order, the final reconciliation of the IIP was to be undertaken in the context of the Company's next filed base rate case. By Petition dated October 11, 2011 the Company filed its final reconciliation of the IIP with the Board and the parties to that proceeding. As provided by the Board's Order in the IIP matter, the Stipulating Parties have reviewed the reconciliation of the IIP as part of this proceeding, and hereby agree that the Company has appropriately completed the projects contemplated by the Board's April 28, 2009 Order.

In reaching this conclusion the Stipulating Parties note that the Company received approximately $3,333,093 in stimulus awards under the American Recovery and Reinvestment Act of 2009 associated with several of the IIP projects, and that the net cost of the IIP was approximately $26.3 million, which is $1.3 million lower than the estimated program costs. The Stipulating Parties agree, therefore, that the Company's IIP program should be determined to be concluded and the Company's rate base set forth herein shall include the $26.3 million of capital investments associated with the IIP. Coincident with the effective date of the distribution rate changes included in this Stipulation, the Infrastructure Investment Surcharge established as part of the IIP will be eliminated, and any over/under recovery will be applied to the NGC deferred balance. The Board's docket in the IIP matter shall be deemed completed and closed.

11. IIP-2. As part of this Settlement, the Company agrees with the Stipulating Parties to withdraw its IIP-2 Petition currently pending before Board, and Commissioner Nicholas Asselta as the designated Hearing Officer, in BPU Docket No. EO11100650. Upon approval of this Stipulation by the Board, the Company will submit a letter to the Board withdrawing its Petition in the IIP-2 matter. In the interim, the Stipulating Parties agree to stay the procedural schedule in the IIP-2 matter, which currently requires Initial Briefs to be filed on October 22, 2012. By withdrawing the IIP-2 Petition at this time, ACE will not be precluded in the future from filing a new Petition seeking infrastructure cost recovery relief from the Board similar to that requested in the IIP-2 matter.

12. Effective Date. The Stipulating Parties agree to present this Stipulation to ALJ Irene Jones immediately upon execution hereof, and will request that the ALJ expeditiously accept the Stipulation in its entirety and return an Initial Decision-Settlement to the Board recommending adoption of this Settlement, in time for the Board to consider this Stipulation at the Board's scheduled October 23, 2012 agenda meeting. The Stipulating Parties further agree that, upon approval of this Stipulation by the Board, the new rates resulting from this Stipulation will become effective for services rendered on and after November 1, 2012, or as soon thereafter as authorized by the Board. The Company agrees to file with the Board compliance tariff sheets within ten (10) business days of receipt of the signed Board Order approving this Stipulation.

13. Consolidated Tax Adjustment. The Company and Rate Counsel agree that the Board should, on its own motion, establish a generic proceeding to review the CTA issue and determine what modifications, if any, are appropriate to the Board's current CTA policy and calculation methodology.

14. Customer Service Improvement Plan and Reliability Improvement Plan. As part of Phase 2 of Petitioner's 2009 base rate case (Order Approving Stipulation dated May 16, 2011, BPU Docket No. ER09080664), the parties to that proceeding proposed a Phase 2 Stipulation to the Board, which included a Customer Service Improvement Plan ("CSIP") and a Reliability Improvement Plan ("RIP"). The Board, by Order dated May 16, 2011, adopted the Phase 2 Stipulation in its entirety (the "Phase 2 Order"). The CSIP, which was developed to address concerns raised by the parties with respect to customer service issues, including customer complaints, and the RIP, whereby the Company committed to spend an additional $40 million on reliability-related infrastructure and other activities, were designed to be implemented over a five year period commencing as of the date of the Board's Phase 2 Order. By the end of that five year period, i.e., May 2016, the Company is expected to achieve certain identified improvement metrics in accordance with the metrics incorporated in the Stipulation that was attached to the Phase 2 Order. As provided for in the Phase 2 Order, the Company will provide to the Board and the parties with annual reports on each respective plan's progress. For the RIP, the initial report was filed on May 31, 2012, as part of the Company's Annual System Performance Report. The initial report for the CSIP was filed on or by August 30, 2012.

The Stipulating Parties are committed to developing procedures that will result in improved customer service and reliability for ACE's customers. To that end, the Stipulating Parties agree that, following the annual filing of the RIP and CSIP, representatives from Staff, the Company and Rate Counsel will engage in quarterly informal consultation with each other to determine if the RIP and/or the CSIP are performing as anticipated, and to discuss additional improvements that can be considered. It is not the intention of the Stipulating Parties for these informal consultations or this Stipulation to alter the terms and conditions of the Board-approved

RIP or CSIP or any other prior Board Order, but rather to allow them to cooperatively monitor the progress that the Company has committed to in these areas, and discuss alternative options should additional progress be deemed necessary and achievable.

MISCELLANEOUS PROVISIONS

15. This Stipulation shall be binding on the Stipulating Parties upon approval by the Board. This Stipulation shall bind the Stipulating Parties in this matter only and shall have no precedential value.

16. This Stipulation contains terms, each of which is interdependent with the others and essential in its own right to the signing of this Stipulation. Each term is vital to the agreement as a whole, since the Stipulating Parties expressly and jointly state that they would not have signed the Stipulation had any term been modified in any way. Since the Stipulating Parties have compromised in numerous areas, each is entitled to certain procedures in the event that any modifications whatsoever are made to the Stipulation.

17. If, upon consideration of this Stipulation, the Board were to modify any of the terms described above, the Stipulating Parties each must be given the right to be placed in the position it was before the Stipulation was entered into. It is essential that each Stipulating Party be afforded the option, prior to the implementation of any new rate resulting from any modification of this Stipulation, either to modify its own position to accept the proposed change(s) or to resume the proceeding as if no agreement had been reached. This proceeding, under such circumstance, would resume at the point where it was terminated.

18. The Stipulating Parties agree that these procedures are fair to all concerned, and therefore, they are made an integral and essential element of this Stipulation.

CONCLUSION

WHEREFORE, for the reasons set forth above, the Stipulating Parties to this Stipulation request that the ALJ and the Board, respectively recommend and approve and adopt this Stipulation and Settlement in its entirety, and issue respectively issue an Initial Decision and a Decision and Order determining that the resolutions of the issues in this proceeding as proposed in this Stipulation are just and reasonable.

[SIGNATURES APPEAR ON THE FOLLOWING PAGE]

	ATLANTIC CITY ELECTRIC COMPANY
Dated: October 12, 2012	By: Passanante Philip J. Passanante Associate General Counsel
	JEFFREY S. CHIESA ATTORNEY GENERAL OF NEW JERSEY Attorney for the Staff of the New Jersey Board of Public Utilities
Dated: October 12, 2012	By: Wand Alex Moreau T. David Wand Deputy Attorneys General
	STEFANIE A. BRAND, ESQ. DIRECTOR DIVISION OF RATE COUNSEL
Dated: Oct. 12, 2012	By: Stefanie A. Brand
	WAL-MART STORES EAST, LP and SAM'S EAST, INC
Dated: ____________	By: ______________________ Michael A. Gruin, Esq. Linda R. Evers, Esq. Stevens & Lee

ATLANTIC CITY ELECTRIC COMPANY

Dated: October 12, 2012

By: ______________________
Philip J. Passanante
Associate General Counsel

JEFFREY S. CHIESA
ATTORNEY GENERAL OF NEW JERSEY
Attorney for the Staff of the New Jersey Board of Public Utilities

Dated: ______________

By: ______________________
Alex Moreau
T. David Wand
Deputy Attorneys General

STEFANIE A. BRAND, ESQ.
DIRECTOR
DIVISION OF RATE COUNSEL

Dated: ______________

By: ______________________

WAL-MART STORES EAST, LP and
SAM'S EAST, INC

Dated: 10/12/12

By: ______________________
Michael A. Gruin, Esq.
Linda R. Evers, Esq.
Stevens & Lee

DSMDB-3091266v1

Exhibit A

Atlantic City Electric Company
Regulatory Asset Recovery Charge (RARC)

Table #1 **Summary of Current BPU Approved Items included in RARC**
Actuals to December 2011

Item		Annual Revenue Requirement
Asbestos Removal Costs	$	270,000
SFAS 106 - Pension/OPEB	$	1,540,000
2008 Management Audit Costs	$	251,941
Deferred Nuclear Fuel Rod Legal Costs	$	378,245
NUG Buyout Costs	$	1,112,801
Reverse RARC Reserve	$	(944,994)
Total Existing Regulatory Asset Recovery	$	2,607,993

Table #2 **Items to be Amortized Over 4 Years**

Item		
LCAPP	$	121,927
Additional Management Audit Not Previously In RARC	$	128,935
Total	$	250,862
Plus:		
Add Unrecovered Expense Associated with RARC In Table 1	$	(138,361)
Net 4 year amortization RARC Expenditures Balances Estimated as of 6/30/2012	$	112,501

Table #3 **Items to be Amortized Over 15 Years**

Item		
Preferred Stock Redemption	$	167,231

Table #4 **Regulatory Asset Recovery Charge Rate Design**

Existing Revenue Requirements	$	2,607,993
Levelized Recovery of New RARC Items 4 yr Amort	$	28,609
Levelized Recovery of New RARC Items 15 Yr Amort	$	11,149
Sub-Total	$	2,647,751
Revenue Requirement Adjusted for BPU/RPA Assessment	$	2,661,056
New Revenue Requirement Adjusted for SUT	$	2,847,330
Annual Sales (kWh)		10,066,988,128
RARC ($/kWh)	$	0.000283

Atlantic City Electric Company
Regulatory Asset Recovery Charge (RARC)
Table #4 Detail
Amortization Schedule for Recovery of Proposed Additional Regulatory Assets
Assets Being Amortized Over 4 Years

	Amortization	Interest	Total
Net Balance to be Recovered	$ 112,501		
Net Balance to be Recovered at June 2012 (a)	$ 112,501	$ 1,935	$ 114,436
Total Periods June 2012 to May 2016 (b)			48
Annualized = (a) / (b) X 12months			$ 28,609
Interest Rate (Pre-Tax)	0.86%	(2-year Treasury rate on 2/10/2012 + 60 B.P.)	
Interest Rate (After-Tax)	0.509%		
Amortization Period (years)	4		

Month	Starting Balance	Amortization	Monthly Interest	Ending Balance
Starting Balance				**$ 112,501**
Jun-12	$ 112,501	$ 2,344	$ 80	$ 110,158
Jul-12	$ 110,158	$ 2,344	$ 78	$ 107,814
Aug-12	$ 107,814	$ 2,344	$ 76	$ 105,470
Sep-12	$ 105,470	$ 2,344	$ 75	$ 103,126
Oct-12	$ 103,126	$ 2,344	$ 73	$ 100,782
Nov-12	$ 100,782	$ 2,344	$ 71	$ 98,439
Dec-12	$ 98,439	$ 2,344	$ 70	$ 96,095
Jan-13	$ 96,095	$ 2,344	$ 68	$ 93,751
Feb-13	$ 93,751	$ 2,344	$ 66	$ 91,407
Mar-13	$ 91,407	$ 2,344	$ 65	$ 89,064
Apr-13	$ 89,064	$ 2,344	$ 63	$ 86,720
May-13	$ 86,720	$ 2,344	$ 61	$ 84,376
Jun-13	$ 84,376	$ 2,344	$ 60	$ 82,032
Jul-13	$ 82,032	$ 2,344	$ 58	$ 79,688
Aug-13	$ 79,688	$ 2,344	$ 56	$ 77,345
Sep-13	$ 77,345	$ 2,344	$ 55	$ 75,001
Oct-13	$ 75,001	$ 2,344	$ 53	$ 72,657
Nov-13	$ 72,657	$ 2,344	$ 51	$ 70,313
Dec-13	$ 70,313	$ 2,344	$ 50	$ 67,970
Jan-14	$ 67,970	$ 2,344	$ 48	$ 65,626
Feb-14	$ 65,626	$ 2,344	$ 46	$ 63,282
Mar-14	$ 63,282	$ 2,344	$ 45	$ 60,938
Apr-14	$ 60,938	$ 2,344	$ 43	$ 58,594
May-14	$ 58,594	$ 2,344	$ 41	$ 56,251
Jun-14	$ 56,251	$ 2,344	$ 39	$ 53,907
Jul-14	$ 53,907	$ 2,344	$ 38	$ 51,563
Aug-14	$ 51,563	$ 2,344	$ 36	$ 49,219
Sep-14	$ 49,219	$ 2,344	$ 34	$ 46,876
Oct-14	$ 46,876	$ 2,344	$ 33	$ 44,532
Nov-14	$ 44,532	$ 2,344	$ 31	$ 42,188
Dec-14	$ 42,188	$ 2,344	$ 29	$ 39,844
Jan-15	$ 39,844	$ 2,344	$ 28	$ 37,500
Feb-15	$ 37,500	$ 2,344	$ 26	$ 35,157
Mar-15	$ 35,157	$ 2,344	$ 24	$ 32,813
Apr-15	$ 32,813	$ 2,344	$ 23	$ 30,469
May-15	$ 30,469	$ 2,344	$ 21	$ 28,125
Jun-15	$ 28,125	$ 2,344	$ 19	$ 25,782
Jul-15	$ 25,782	$ 2,344	$ 18	$ 23,438
Aug-15	$ 23,438	$ 2,344	$ 16	$ 21,094
Sep-15	$ 21,094	$ 2,344	$ 14	$ 18,750
Oct-15	$ 18,750	$ 2,344	$ 13	$ 16,406
Nov-15	$ 16,406	$ 2,344	$ 11	$ 14,063
Dec-15	$ 14,063	$ 2,344	$ 9	$ 11,719
Jan-16	$ 11,719	$ 2,344	$ 8	$ 9,375
Feb-16	$ 9,375	$ 2,344	$ 6	$ 7,031
Mar-16	$ 7,031	$ 2,344	$ 4	$ 4,688
Apr-16	$ 4,688	$ 2,344	$ 3	$ 2,344
May-16	$ 2,344	$ 2,344	$ 1	$ (0)
Totals		$ 112,501	$ 1,935	

Atlantic City Electric Company
Regulatory Asset Recovery Charge
Development of RARC Reserve Balance

	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11
RARC Revenue	$ 284,514	$ 242,588	$ 314,731	$ 269,222	$ 205,499	$ 167,357	$ 202,239	$ 239,076	$ 195,324	$ 196,951	$ 172,491	$ 178,570
RARC Amortization Expense												
Asbestos	$ -	$ -	$ -	$ 89,959	$ 22,490	$ 22,490	$ 22,490	$ 22,490	$ 22,490	$ 22,490	$ 22,490	$ 22,490
OPEB	$ -	$ -	$ -	$ 513,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333
May 2010 Stipulation Items												
2008 Management Costs	$ 20,321	$ 20,335	$ 20,349	$ 20,363	$ 20,377	$ 20,391	$ 20,405	$ 20,419	$ 20,433	$ 20,447	$ 20,462	$ 20,476
Deferred Nuclear Fuel Rod Legal Costs	$ 30,508	$ 30,529	$ 30,550	$ 30,571	$ 30,592	$ 30,614	$ 30,635	$ 30,656	$ 30,677	$ 30,698	$ 30,719	$ 30,741
NJ NUG Buyout Costs - General	$ 66,536	$ 66,582	$ 66,628	$ 66,674	$ 66,720	$ 66,766	$ 66,812	$ 66,858	$ 66,904	$ 66,950	$ 66,997	$ 67,043
NJ NUG Buyout Costs - Logan	$ 9,206	$ 9,213	$ 9,219	$ 9,226	$ 9,232	$ 9,238	$ 9,245	$ 9,251	$ 9,257	$ 9,264	$ 9,270	$ 9,277
NJ NUG Buyout Costs - Carneys	$ 14,013	$ 14,022	$ 14,032	$ 14,042	$ 14,051	$ 14,061	$ 14,071	$ 14,080	$ 14,090	$ 14,100	$ 14,110	$ 14,119
Amortize Existing RARC Reserve	$ (76,220)	$ (76,273)	$ (76,326)	$ (76,378)	$ (76,431)	$ (76,484)	$ (76,537)	$ (76,590)	$ (76,642)	$ (76,695)	$ (76,748)	$ (76,801)
	$ 64,364	$ 64,408	$ 64,453	$ 667,789	$ 215,364	$ 215,409	$ 215,454	$ 215,498	$ 215,543	$ 215,587	$ 215,633	$ 215,678
Interest	$ 2,136	$ 2,091	$ 2,047	$ 2,002	$ 1,958	$ 1,913	$ 1,869	$ 1,824	$ 1,779	$ 1,735	$ 1,690	$ 1,645
RARC Reserve	$ (218,014)	$ (176,088)	$ (248,232)	$ 400,569	$ 11,823	$ 49,965	$ 15,084	$ (21,754)	$ 21,998	$ 20,371	$ 44,832	$ 38,754
Cumulative RARC Reserve Balance	$ (218,014)	$ (394,102)	$ (642,334)	$ (241,765)	$ (229,942)	$ (179,977)	$ (164,894)	$ (186,648)	$ (164,650)	$ (144,279)	$ (99,447)	$ (60,693)

	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
RARC Revenue	$ 222,326	$ 272,645	$ 277,309	$ 278,761	$ 195,047	$ 168,997	$ 183,841
RARC Amortization Expense							
Asbestos	$ 22,490	$ 22,490	$ 22,490	$ 22,490	$ 22,490	$ 22,490	$ 22,490
OPEB	$ 128,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333	$ 128,333
May 2010 Stipulation Items							
2008 Management Costs	$ 20,490	$ 20,504	$ 20,518	$ 20,532	$ 20,546	$ 20,561	$ 20,575
Deferred Nuclear Fuel Rod Legal Costs	$ 30,762	$ 30,783	$ 30,804	$ 30,826	$ 30,847	$ 30,868	$ 30,889
NJ NUG Buyout Costs - General	$ 67,090	$ 67,136	$ 67,182	$ 67,228	$ 67,275	$ 67,321	$ 67,368
NJ NUG Buyout Costs - Logan	$ 9,283	$ 9,289	$ 9,296	$ 9,302	$ 9,309	$ 9,315	$ 9,322
NJ NUG Buyout Costs - Carneys	$ 14,129	$ 14,139	$ 14,149	$ 14,158	$ 14,168	$ 14,178	$ 14,188
Amortize Existing RARC Reserve	$ (76,854)	$ (76,907)	$ (76,960)	$ (77,014)	$ (77,067)	$ (77,120)	$ (77,173)
	$ 215,723	$ 215,767	$ 215,812	$ 215,856	$ 215,901	$ 215,946	$ 215,991
Interest	$ 1,600	$ 1,556	$ 1,511	$ 1,466	$ 1,421	$ 1,376	$ 1,331
RARC Reserve	$ (5,002)	$ (55,323)	$ (59,987)	$ (61,438)	$ 22,275	$ 48,325	$ 33,481
Cumulative RARC Reserve Balance	$ (65,695)	$ (121,018)	$ (181,005)	$ (242,443)	$ (220,168)	$ (171,842)	$ (138,361)

Exhibit B

ATLANTIC ELECTRIC

TARIFF
FOR
ELECTRIC SERVICE

SECTION II - STANDARD TERMS AND CONDITIONS

ATLANTIC CITY ELECTRIC COMPANY
General Offices

500 N. Wakefield Drive
Newark, DE 19702

TERMS AND CONDITIONS OF SERVICE

Table of Contents (Continued)

TERMS AND CONDITIONS OF SERVICE

1. GENERAL INFORMATION

1.1 Filing:
This tariff, comprising service rules, regulations and rate schedules governing supply of electric service within the service area of the Atlantic City Electric Company, is the official tariff of the Company on file with the Board of Public Utilities of the State of New Jersey.

1.2 Scope:
The provisions of this tariff shall apply to all persons, natural or artificial and including, but not limited to, partnerships, associations, corporations (private and public), bodies politic, governmental agencies and any other customer receiving electric service hereunder. These “Terms and Conditions” are subject to modifications embodied in “Special Terms and Conditions” of the particular rate schedule under which such customers may be served.

1.3 Revisions:
No agent, representative or employee of the Company is authorized to waive or change the provisions of this tariff, nor shall any agreement or promise to do so be binding upon the Company. Revisions may be made only in compliance with orders of the Board of Public Utilities.

1.4 Other Publications:
Publications set forth by title in these Terms and Conditions of Service are incorporated in these Terms and Conditions of Service by reference.

This tariff is subject to the lawful orders of the Board of Public Utilities of the State of New Jersey. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, Trenton, NJ 08625, 609-341-9188 or 1-800-624-0241; www.nj.gov/bpu.

TERMS AND CONDITIONS OF SERVICE

2. OBTAINING SERVICE

2.1 Application:

Application for service shall be made at nearest Company business office, in person, by mail or by telephone, facsimile transmission and electronic mail where available. At the Company's discretion, a signed application may be required, which when duly accepted by the Company, shall constitute evidence of the agreement between the Company and the customer. A copy of the application will be furnished to the customer upon request.

All customers shall be given a copy of the "Customer Bill of Rights" approved by the Board of Public Utilities, effective at the time of service initiation. The copy shall be presented no later than at the time of the issuance of the customer's first bill or 30 days after the initiation of service, whichever is later.

2.2 Choice of Schedule:

A copy of the Schedules and "Terms and Conditions" under which service is to be rendered to the customer will be furnished upon application at the Company's office, and the customer may choose the appropriate rate schedule applicable to his service, upon which his application shall be based. He may not change from one schedule to another except by mutual agreement. If customer so desires, the choice of schedule may be discussed with designated Company representatives who will assist in explaining the advantages of each applicable schedule. On request, representative will also explain method of reading meters.

2.3 Deposits:

A deposit may be required of the customer before service will be supplied. Such deposit shall be the estimated average bill of the customer for a billing period based upon the average monthly charge over an estimated 12 month service period increased by one month average bill Customers in default in the payment of bills shall be required to furnish a deposit or increase their existing deposit in an amount sufficient to secure the payment of future bills. The Company will pay interest on deposits so made at not less than such rate as may be required by the New Jersey Board of Public Utilities for residential accounts at least once during each 12-month period in which a deposit is held. The Company will furnish a receipt to each customer who has made a deposit. If a customer who has made a deposit fails to pay a bill, the Company may apply such deposit insofar as is necessary to liquidate the bill, and may require that the deposit be restored to its original amount. The Company shall review a residential customer's account at least once every year, and a non-residential customer's account at least once every two years and if such review indicates that the customer has established credit satisfactory to the utility, then the outstanding deposit shall be returned to the customer.

Upon refunding a deposit or paying a customer interest on a deposit, the company shall offer the customer the option of a credit to the customer's account or a separate check.

Upon closing an account, the company shall refund to the customer the balance of any deposit remaining after the closing bill for service has been settled, including any interest required.

TERMS AND CONDITIONS OF SERVICE

5. COMPANY'S EQUIPMENT

5.1 Installation on Customer's Property:

The customer shall grant the Company the right to construct required service facilities on the customer's property and place its meters and other apparatus on the property or within the buildings of the customer, at a point or points mutually agreed to for such purpose, and the customer shall further guarantee the right to use suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the customer or of any employee of the customer. The Company shall not install transformers within the buildings of the customers. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2 and N.J.A.C. 14:5.

5.2 Maintenance of Company's Equipment:

The Company will provided and maintain in proper operative condition the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

5.3 Attachment to Company Owned Facilities:

No radio transmitting, receiving, television, or other antennae may be connected to the Company's lines nor attached to its poles, crossarms, structures or other facilities. No signs nor devices of any type may be attached to the Company's poles, structures, or other facilities without the written consent of the Company.

5.4 Right of Entrance to Customer's Premises:

The Company shall have the right at all reasonable hours to enter the premises of the customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause.

The Company shall have the right of reasonable access to a customer's premises, and to all property on the customer's premises which is furnished by the company, at all reasonable times for the purpose of inspection of customer's premises incident to the rendering of service including reading meters; inspecting, testing, or repairing its facilities used in connection with supplying service, or the removal of its property. The Company has the right of entire removal of the Company's property in the event of the termination of the contract for any cause.

Access to the Company's facilities shall not be given except to authorized employees of the Company or duly authorized government officials.

TERMS AND CONDITIONS OF SERVICE

6. METERING, BILLING AND PAYMENT FOR SERVICE

6.1 Meters:
Meters shall be owned and maintained by the Company in accordance with Section 5 above**.** The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2 and N.J.A.C. 14:5.

6.2 Special Testing of Meters:
Meters shall be tested in accordance with regulations of the Board of Public Utilities. The customer may request an accuracy test be made by the Company at no charge provided such request for test is not made more frequently than once in 12 months. If a Customer requests an accuracy test more frequently than once in 12 months, a service charge will be made as specified in Rate Schedule CHG. Whenever a meter is found to register faster than the amount allowed by the Board, test fee will be waived. Complete reports of the results of such tests will be available to the customer and will be kept on file by the Company in accordance with Board of Public Utilities' regulations. Customers may also request that a test be made by an inspector of the Board of Public Utilities. There is a fee for such tests which must be paid by the customer to the Board. If the meter is found to be "fast" beyond the allowable limits, the Company will reimburse the customer for the fee paid by him.

6.3 Adjustment of Bill:
Whenever a meter is found to be registering "fast" in excess of the allowable limits established by the Board of Public Utilities, an adjustment shall be made corresponding to the percentage error as found in the meter covering the entire period during which the meter registered inaccurately, provided such period can be determined. Where such period cannot be determined, a correction shall be applied to ½ of the total amount of billing affected since the previous test. No adjustment shall be made for a period greater than the time during which the customer has received service through the meter in question. Billing adjustments shall be in accordance with N.J.A.C. 14:3-4.6.

TERMS AND CONDITIONS OF SERVICE

6. METERING, BILLING AND PAYMENT FOR SERVICE (Continued)

6.4 Payment of Bills:

Bills are payable upon presentation, at any business office of the Company, or any authorized collection agency. The Company may require earlier payment to prevent fraud or illegal use of energy, or when it is clearly evident that customer is preparing to vacate the premises.

Overdue bills for non-residential customers are subject to a late payment charge as specified on Rate Schedule CHG. This charge will be applied to amounts billed including accounts payable and unpaid late payment charge amounts applied to previous bills, which are not received by the Company within forty-five (45) days for non-residential customers, and within sixty (60) days for governmental bodies following the due date specified on the bill. The amount of the late payment charge to be added to the unpaid balance for non-residential and governmental customers shall be determined by multiplying the unpaid balance by the late payment charge rate as specified in Rate Schedule CHG. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

New Jersey Public Utilities, subject to the New Jersey State Excise Tax, shall be billed net of such taxes.

Bills are payable at any location identified by the Company as a payment office or authorized collection agency, within twenty (20) days of the postmarked date.

6.5 Billing Period:

Except as hereinafter provided under normal course of business, customers shall be billed monthly. Bills for other than thirty (30) days shall be properly prorated. Where credit situations require, the Company may read meters and render bills at shorter intervals.

TERMS AND CONDITIONS OF SERVICE

7. DISCONNECTION AND RECONNECTION

7.1 Disconnection at Customer's Request:
The Company will disconnect service at request of customer and will render a final bill in accordance with applicable schedule. At such time as the customer shall request disconnection, a charge as specified on Rate Schedule CHG shall be made. Notice to disconnect will not relieve the customer from any minimum or guaranteed payment established by contract or rate schedule.

Within 48 hours of said notice, the company shall discontinue service or obtain a meter reading for the purpose of calculating a final bill.

7.2 Disconnection for Non-Payment or Non-Compliance:
The Company reserves the right to discontinue its service when: the customer's arrearage is more than $100.00 and/or the customer's account is more than three months in arrears; for failure to comply with these Terms and Conditions; to prevent fraud upon the Company, or where use of energy is not in accordance with the Company's schedules. The Company shall, upon due notice, discontinue service to any customer reported by a duly authorized inspection agency to be in violation of county, municipal or National Electrical Codes, or reported to be in violation of any governmental order or directive concerning the use of energy. Any such disconnection of service shall not terminate the contract for special extensions or special facilities between the Company and the customer. A service charge will be made as specified on Rate Schedule CHG. No charge will be due on those instances done at the convenience of the Company.

7.3 Disconnection for Other Reasons:
In addition to the provisions of Subparagraph 7.2 above, the Company may disconnect service for any of the following causes:

A. For the purpose of effecting repairs.
B. In compliance with governmental order or directive.
C. Refusal of customer to contract for service where such contract is provided for in applicable schedule.
D. Where condition of customer's electric facilities are such as to involve a hazard to life or property.

A service charge will be made as specified on Rate Schedule CHG. No charge will be due on those instances done at the convenience of the Company.

TERMS AND CONDITIONS OF SERVICE

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS (Continued)

11.4 Change of Alternative Electric Supplier
The Company shall not initiate or change a Customer's Alternative Electric Supplier unless the requirements set forth by the BPU pursuant to its Orders dated March 17, 1999 and May 5, 1999 (Docket Nos. EX94120585Y, etc.) or future BPU Orders have been complied with by both the Customer and the Alternative Electric Supplier.

11.5 Late Payment Charges
In the case of electric supply furnished by an Alternative Electric Supplier, Subparagraph 6.4 of these Terms and Conditions is to be applicable only to Company charges. Customer shut-offs in cases where there is non-payment to the Company for its delivery charges are only performed in accordance with Subparagraph 7.2 of these Terms and Conditions.

TERMS AND CONDITIONS OF SERVICE

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS (Continued)

11.6 Billing Disputes

In the event of a billing dispute between the customer and the Alternative Electric Supplier, the Company's sole duty is to verify its charges and billing determinants. The customer is responsible for the timely payment of all Company charges in accordance with Subparagraph 6.4 of these Terms and Conditions, regardless of Alternative Electric Supplier billing disputes. All questions regarding Alternative Electric Suppliers' charges or other terms of the customer's agreement with the Alternative Electric Supplier are to be resolved between the customer and the Alternative Electric Supplier. The Company will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between Alternative Electric Suppliers and their customers.

11.7 Liability for Supply or Use of Electric Service

The Company will not be responsible for the use, care, condition, quality or handling of the Service delivered to the Customer after same passes beyond the point at which the Company's service facilities connect to the Customer's wires and facilities. The Customer shall hold the Company harmless from any claims, suits or liability arising, accruing, or resulting from the supply to, or use of Service by, the Customer.

11.8 Liability for Acts of Alternative Electric Suppliers

The Company shall have no liability or responsibility whatsoever to the Customer for any agreement, act or omission of, or in any way related to, the Customer's Alternative Electric Supplier.

ATLANTIC ELECTRIC

TARIFF
FOR
ELECTRIC SERVICE

SECTION III - RATE SCHEDULE RUE - RESIDENTIAL UNDERGROUND EXTENSIONS AND CLE - CONTRIBUTED LIGHTING EXTENSIONS

ATLANTIC CITY ELECTRIC COMPANY
General Offices

500 N. Wakefield Drive
Newark, DE 19702

RATE SCHEDULE CLE
(Contributed Lighting Extension)

AVAILABILITY OF SERVICE
Required for new or additional lighting fixtures contracted for under Rate Schedule CSL.

RATE
All charges under the CLE tariff are subject to federal income tax liability pursuant to the Tax Reform Act of 1986 and the Revenue Reconciliation Act of 1993. For each fixture the customer shall pay the Company the amount determined from the following table plus any applicable tax gross up.

New HPS lighting fixture & bracket (4' or 8')
(installed on existing pole/prepaid facilities):

Standard		
Up to and including	150 watt	$319.53
Over	150 watt	$441.33
Shoe Box	All	$751.01
Post Top	All	$545.88
Flood/Profile Light		
	Standard HPS	$635.00
	Standard Metal Halide	$546.69

Induction

Cobra Head	40 Watt	$ 574.61
Cobra Head	80 Watt	$ 618.30
Cobra Head	150 Watt	$ 642.18
Cobra Head	200 Watt	$ 749.65

RATE SCHEDULE CLE (Continued)
(Contributed Lighting Extension)

Light Emitting Diode

Cobra Head	50 W	$ 714.57
	70 W	$ 751.92
	100 W	$ 858.68
	150 W	$ 977.58
	250 W	$ 1,141.15
Tear Drop Decorative	70 W	$ 1,553.62
	100 W	$ 1,557.31
	150 W	$ 1,771.71
	250 W	$ 1,708.51
Decorative Post Top	70 W	$ 1,342.12
	100 W	$ 1,373.70
	150 W	$ 1,446.39
Decorative Post Top w/ribs	70 W	$ 1,384.56
	100 W	$ 1,387.92
	150 W	$ 1,488.84
Colonial Style Post Top	70 W	$ 1,177.70
	100 W	$ 1,217.35
	150 W	$ 1,290.04
Shoe Box	100 W	$ 1,039.21
	150 W	$ 1,155.94
	250 W	$ 1,355.23

*Plus $73.88 if existing incandescent HID fixture is removed.
*Plus $57.03 if existing mercury vapor HID fixture is removed.
*Less $25.14 (bracket credit) if existing HID fixture is removed but existing bracket is reused.

Plus additional charges for:

14 Ft. Bracket	$145.47
24 Ft. Ornamental standard (single bracket)	$2,385.98
24 Ft. Ornamental standard (double bracket)	$3,302.20
25 Ft. Bracket	$1,140.68
26 Ft. Tangent ornamental standard (single bracket)	$2,989.51
26 Ft. Tangent ornamental standard (double bracket)	$3,709.66
26 Ft. Corner ornamental standard	$2,975.48
25 Ft. Square aluminum ornamental standard	$3,001.55

*These items are considered a reimbursement of capital without any tax liability associated with the Tax Reform Act of 1986 and the Revenue Reconciliation Act of 1993.

RATE SCHEDULE CLE (Continued)
(Contributed Lighting Extension)

SPECIAL TERMS AND CONDITIONS

All equipment covered by this schedule will remain the company's property unless, under special situation where ownership of the above equipment is advantageous to the state or local governmental entity involved, special contractual arrangements can be made.

Capital costs for specialty lighting applications will be provided upon request.

The "new charge per fixture" applies to all areas. In RUE areas, additional charges are collected under the RUE tariff.

Repavement of concrete broken for installation will be at actual cost or accomplished by the customer.

See Section II inclusive for Terms and Conditions of Service

ATLANTIC ELECTRIC

TARIFF
FOR
ELECTRIC SERVICE

SECTION IV - SERVICE CLASSIFICATIONS AND RIDERS

ATLANTIC CITY ELECTRIC COMPANY

General Offices

500 N. Wakefield Drive
Newark, DE 19702

RATE SCHEDULE CHG
(Charges)

APPLICABILITY OF SERVICE
Applicable to all customers in accord with the tariff paragraph noted below

SERVICE CHARGES

1. Installation of Service at Original Location
(See Section II paragraph 2.9)... .... $65.00

2. Connection, Reconnection, or Succession
of Service at Existing Location
(See Section II paragraphs 2.10 and 2.11).......... .... $15.00

3. Disconnection (See Section II paragraph 7.1, 7.2, or 7.3).......................... $15.00

4. Special Reading of Meters (See Section II paragraph 6.7) $15.00

LATE PAYMENT CHARGES

(See paragraph 6.4) .... 0.877% Per Month
(Non-residential only) .... (10.52% APR)

UNCOLLECTIBLE CHECKS

(See paragraph 6.9) .... $ 7.64

"In accordance with P.L. 1997,c.192, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires on January 1, 2003, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein."

RATE SCHEDULE RS
(Residential Service)

AVAILABILITY
Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge ($/Month)	$3.00	$3.00
Distribution Rates ($/kWH)		
First Block	$0.037104	$0.036328
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.042658	$0.031050
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Asset Recovery Charge (RARC) ($/kWh)	See Rider RARC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
Transmission Service Charges ($/kWh):		
Transmission Rate	$0.010080	$0.010080
Reliability Must Run Transmission Surcharge	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)
Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$5.21	$5.21
Three Phase	$6.51	$6.51
Distribution Demand Charge (per kW)	$1.57	$1.29
Reactive Demand Charge	$0.40	$0.40
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.041315	$0.037321
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$5.68	$5.30
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

The minimum monthly bill will be $6.51 per month plus any applicable adjustment.

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)
Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER	**WINTER**
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$5.21	$5.21
Three Phase	$6.51	$6.51
Distribution Demand Charge (per kW)	$1.39	$1.08
Reactive Demand Charge	$0.40	$0.40
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.039436	$0.038301
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge	$5.76	$5.41
($/kW for each kW in excess of 3 kW)		
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative		
Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

The minimum monthly bill will be $6.51 per month plus any applicable adjustment.

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)
Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$152.46	
Distribution Demand Charge ($/kW)	$6.74	
Reactive Demand (for each kvar over one-third of kW demand)	$0.51	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$1.84	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:		
Customer Charge	$698.21	
Distribution Demand Charge ($/kW)	$5.63	
Reactive Demand (for each kvar over one-third of kW demand)	$0.42	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$1.90	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

RATE SCHEDULE TGS
(Transmission General Service)
(Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges:

Customer Charge		$5,827.01
Distribution Demand Charge ($/kW)		$0.94
Reactive Demand (for each kvar over one-third of kW demand)		$0.17
Non-Utility Generation Charge (NGC) ($/kWH)		See Rider NGC
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge		See Rider SBC
Clean Energy Program		See Rider SBC
Universal Service Fund		See Rider SBC
Lifeline		See Rider SBC
Uncollectible Accounts		See Rider SBC
Regulatory Assets Recovery Charge ($/kWh)		See Rider RARC
Transition Bond Charge (TBC) ($/kWh)		See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)		See Rider SEC
System Control Charge (SCC) ($/kWh)		See Rider BGS
CIEP Standby Fee ($/kWh)		See Rider BGS
Transmission Demand Charge ($/kW)		$2.10
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)		See Rider BGS
Basic Generation Service Charge ($/kWh)		See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)		See Rider RGGI
Infrastructure Investment Surcharge		See Rider IIS

RATE SCHEDULE TGS
(Transmission General Service)
(Transmission Service Taken at or above 69kV)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$20,093.47	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$2.10	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY

Available at any point of the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection)	$0.157534
Energy (per day for each kW of effective load)	$0.758780
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Consumer Education Program Charge	See Rider SBC
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline See Rider SBC	
Uncollectible Accounts	See Rider SBC
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
System Control Charge (SCC) ($/kWh)	See Rider BGS
Transmission Rate ($/kWh)	$0.003487
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)

Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION

Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

RATE SCHEDULE SPL
(Street and Private Lighting)

AVAILABILITY OF SERVICE

Available for general lighting service in service by December 14, 1982, new lights requested for installation before January 1, 1983 or high pressure sodium fixtures in the area served by the Company.

The Company will provide and maintain a lighting system and provide fixture and electric energy sufficient to operate said fixture continuously, automatically controlled, from approximately one-half hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth.

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Distribution charges are billed on a monthly per light basis in accordance with the rates specified on the Tables on Sheets 36, 36a and 37.

Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Consumer Education Program Charge	See Rider SBC
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
System Control Charge (SCC) ($/kWh)	See Rider BGS
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.000000
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

RATE SCHEDULE SPL (Continued)
(Street and Private Lighting)

RATE (Mounted on Existing Pole)

	WATTS	LUMENS	MONTHLY DISTRIBUTION CHARGE	STATUS
INCANDESCENT				
Standard	103	1,000	$ 4.59	Closed
Standard	202	2,500	$ 7.99	Closed
Standard	327	4,000	$ 11.14	Closed
Standard	448	6,000	$ 14.91	Closed
MERCURY VAPOR				
Standard	100	3,500	$ 7.73	Closed
Standard	175	6,800	$ 10.34	Closed
Standard	250	11,000	$ 13.11	Closed
Standard	400	20,000	$ 18.91	Closed
Standard	700	35,000	$ 30.18	Closed
Standard	1,000	55,000	$ 41.06	Closed
HIGH PRESSURE SODIUM				
Retrofit	150	11,000	$ 9.48	Closed
Retrofit	360	30,000	$ 17.70	Closed

RATE (Overhead/RUE)

	WATTS	LUMENS	MONTHLY DISTRIBUTION CHARGE	STATUS
HIGH PRESSURE SODIUM				
Cobra Head	50	3,600	$ 8.43	Open
Cobra Head	70	5,500	$ 8.73	Open
Cobra Head	100	8,500	$ 9.20	Open
Cobra Head	150	14,000	$ 10.03	Open
Cobra Head	250	24,750	$ 14.23	Open
Cobra Head	400	45,000	$ 16.48	Open
Shoe Box	150	14,000	$ 12.24	Open
Shoe Box	250	24,750	$ 15.89	Open
Shoe Box	400	45,000	$ 18.37	Open
Post Top	50	3,600	$ 9.36	Open
Post Top	100	8,500	$ 10.20	Open
Post Top	150	14,000	$ 12.04	Open
Flood/Profile	150	14,000	$ 9.82	Open
Flood/Profile	250	24,750	$ 12.43	Open
Flood/Profile	400	45,000	$ 15.90	Open
METAL HALIDE				
Flood/Profile	400	31,000	$ 19.54	Open
Flood/Profile	1,000	96,000	$ 33.35	Open

RATE SCHEDULE SPL (Continued)
(Street and Private Lighting)

	WATTS	LUMENS	MONTHLY DISTRIBUTION CHARGE	STATUS
Experimental LIGHT EMITTING DIODE (LED)				
Cobra Head	50	3,000	$ 10.23	Open
Cobra Head	70	4,000	$ 10.67	Open
Cobra Head	100	7,000	$ 11.93	Open
Cobra Head	150	10,000	$ 13.33	Open
Cobra Head	250	17,000	$ 15.26	Open
Post Top	70	4,000	$ 17.64	Open
Post Top	100	7,000	$ 18.01	Open
Post Top	150	10,000	$ 18.87	Open
Post Top w/ Ribs	70	4,000	$ 18.14	Open
Post Top w/ Ribs	100	7,000	$ 18.18	Open
Post Top w/ Ribs	150	10,000	$ 19.37	Open
Colonial Post Top	70	4,000	$ 15.70	Open
Colonial Post Top	100	7,000	$ 16.16	Open
Colonial Post Top	150	10,000	$ 17.02	Open
Shoe Box	100	7,000	$ 14.06	Open
Shoe Box	150	10,000	$ 15.44	Open
Shoe Box	250	17,000	$ 17.79	Open
Tear Drop	70	4,000	$ 20.13	Open
Tear Drop	100	7,000	$ 20.18	Open
Tear Drop	150	10,000	$ 22.71	Open
Tear Drop	250	17,000	$ 21.96	Open
Experimental INDUCTION				
Cobra Head	40	3,000	$ 3.76	Open
Cobra Head	80	6,300	$ 4.11	Open
Cobra Head	150	11,500	$ 4.58	Open
Cobra Head	250	21,000	$ 5.47	Open

RATE SCHEDULE SPL (Continued)
(Street and Private Lighting)

RATE (Underground)

	WATTS	LUMENS	MONTHLY DISTRIBUTION CHARGE	STATUS
HIGH PRESSURE SODIUM				
Cobra Head	50	3,600	$ 12.98	Open
Cobra Head	70	5,500	$ 13.28	Open
Cobra Head	100	8,500	$ 13.74	Open
Cobra Head	150	14,000	$ 14.58	Open
Cobra Head	250	24,750	$ 17.66	Open
Cobra Head	400	45,000	$ 19.89	Open
Shoe Box	150	14,000	$ 16.81	Open
Shoe Box	250	24,750	$ 20.43	Open
Shoe Box	400	45,000	$ 22.92	Open
Post Top	50	3,600	$ 16.81	Open
Post Top	100	8,500	$ 20.43	Open
Post Top	150	14,000	$ 22.92	Open
Flood/Profile	150	14,000	$ 15.38	Open
Flood/Profile	250	24,750	$ 17.98	Open
Flood/Profile	400	45,000	$ 20.47	Open
Flood/Profile	400	31,000	$ 24.20	Open
Flood/Profile	1000	96,000	$ 38.00	Open

Bill will be rendered monthly and be prorated based on the billing cycle

Lamp sizes listed are standard ratings. Actual output shall be within commercial tolerances. The mercury vapor post standard (no longer available) will be supplied at an annual cost of $23.09 in addition to the appropriate rate for the facility mounted on an existing pole. For installations on or before January 17, 1986, or lamp sizes 3500 Lumen or greater, an ornamental standard will be supplied at an annual cost of $76.71 in addition to the appropriate rate for the fixture mounted on an existing pole. For standards installed after January 17, 1986, non-ornamental standards are available at an annual cost of $112.13 in addition to the appropriate rate for the fixture mounted on an existing pole. Installation charges may be required for new construction. Ornamental standards are available under the CLE rate schedule.

UPGRADES TO EXISTING FIXTURES
Customers may upgrade existing lighting fixtiures to fixtures of higher wattage subject to payment of the following charges which provide for labor to replace the light fixture and the differential cost of the light fixture:

Lamp Size up to 150W:	$339.80 plus applicable income tax gross up
Lamp Size greater than 150W:	$430.74 plus applicable income tax gross up

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)
Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.
CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.
NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RATE SCHEDULE SPL (Continued)
(Street and Private Lighting)

TERM OF CONTRACT

Contracts under this schedule will be made for a period of not less than one (1) year or more than five (5) years and for specified numbers and sizes of fixtures. In no case shall the Company be obliged to furnish additional lighting under any contract for a period of two (2) years or less, or during the last two (2) years of any contract for a longer period unless the customer shall reimburse the Company for all expenses incurred in the running of additional lines for such fixtures, the cost of such fixtures and the cost of the installation.

CREDITS

The annual charge per unit reflects an outage allowance based on normal and abnormal operating conditions.

TERMS AND CONDITIONS OF SERVICE

See Section II inclusive for Terms and Conditions of Service.

Customers requiring service under unusual conditions, or whose service requirements are different from those provided for herein may obtain such service under mutually acceptable contractual arrangements.

Service to all incandescent, mercury vapor, and retrofit high pressure sodium lamps of all sizes is in the process of elimination and is limited to those lamps being served prior to January 1, 1983.

Upon removal of incandescent and mercury vapor fixtures before the expiration of their service lives, the customer will be responsible to reimburse the Company the average undepreciated value per fixture. Refer to Rate Schedule CLE.

<u>Conversion to Rate Schedule CSL</u>

Non-residential customers taking service under Rate Schedule SPL who are eligible to take service under Rate Schedule CSL may convert at anytime. The customer will be required to pay a rate schedule conversion charge, assessed on a per fixture basis, based on the following conditions:

Lighting Installations less than or equal to five years of age:	Full Installation costs per Rate Schedule CLE
Light Installations Greater than five years of age	Labor Costs associated with street light replacement. ($271.15, plus applicable federal income tax gross up.)

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires on January 1, 2003, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. . Customers who receive electric supply from a third party supplier will continue to be billed the System Control Charge (SCC) and, as applicable to customers eligible for BGS CIEP, the CIEP Standby Fee .

RATE SCHEDULE CSL
(Contributed Street Lighting)

AVAILABILITY
Available for general lighting service in the service area of the Company
The Company will install and maintain a lighting system and provide electric energy sufficient to operate fixtures continuously, automatically controlled, for approximately one-half-hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth. The installed cost of the fixtures, standards, and other installed equipment (if necessary) shall be paid by the customer upon installation. All equipment shall be the property of the Company (see Rate Schedule CLE). The rates below provide for ordinary maintenance and replacement of lamps and automatic controls. The rates below do not provide for replacement due to expiration of the service life of installed fixtures, standards or other equipment.

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Delivery charges are billed on a monthly per light basis in accordance with the rates specified on the Tables on Sheets 40 and 40a.

Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Consumer Education Program Charge	See Rider SBC
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Regulatory Assets Recovery Charge ($/kWh)	See Rider RARC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
System Control Charge (SCC) ($/kWh)	See Rider BGS
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.000000
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)
Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

PRICE TO COMPARE
A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. . Customers who receive electric supply from a third party supplier will continue to be billed the System Control Charge (SCC) and, as applicable to customers eligible for BGS CIEP, the CIEP Standby Fee.

RATE SCHEDULE CSL (continued)
(Contributed Street Lighting)
RATE (Mounted on Existing Pole)

	WATTS	LUMENS	MONTHLY DISTRIBUTION CHARGE	STATUS
HIGH PRESSURE SODIUM				
All	50	3,600	$ 3.56	Open
All	70	5,500	$ 3.88	Open
All	100	8,500	$ 4.33	Open
All	150	14,000	$ 5.18	Open
All	250	24,750	$ 7.06	Open
All	400	45,000	$ 9.35	Open
Experimental LIGHT EMITTING DIODE (LED)				
Cobra Head	50	3,000	$ 1.80	Open
Cobra Head	70	4,000	$ 1.80	Open
Cobra Head	100	7,000	$ 1.80	Open
Cobra Head	150	10,000	$ 1.80	Open
Cobra Head	250	17,000	$ 1.80	Open
Post Top	70	4,000	$ 1.80	Open
Post Top	100	7,000	$ 1.80	Open
Post Top	150	10,000	$ 1.80	Open
Post Top w/ Ribs	70	4,000	$ 1.80	Open
Post Top w/ Ribs	100	7,000	$ 1.80	Open
Post Top w/ Ribs	150	10,000	$ 1.80	Open
Colonial Post Top	70	4,000	$ 1.80	Open
Colonial Post Top	100	7,000	$ 1.80	Open
Colonial Post Top	150	10,000	$ 1.80	Open
Shoe Box	100	7,000	$ 1.80	Open
Shoe Box	150	10,000	$ 1.80	Open
Shoe Box	250	17,000	$ 1.80	Open
Tear Drop	70	4,000	$ 1.80	Open
Tear Drop	100	7,000	$ 1.80	Open
Tear Drop	150	10,000	$ 1.80	Open
Tear Drop	250	17,000	$ 1.80	Open
Experimental INDUCTION				
Cobra Head	40	3,000	$ 1.80	Open
Cobra Head	80	6,300	$ 1.80	Open
Cobra Head	150	11,500	$ 1.80	Open
Cobra Head	250	21,000	$ 1.80	Open

Bill will be rendered monthly and be prorated based on the billing cycle

Lamp sizes listed are standard ratings. Actual output shall be within commercial tolerances.
For fixtures mounted on an existing ornamental standard, the existing standard will continue to be supplied at an annual cost of $65.81 until the expiration of its service life in addition to the appropriate rate for the fixtures on an existing pole.

RATE SCHEDULE CSL (continued)
(Contributed Street Lighting)

UPGRADES TO EXISTING FIXTURES
Customers may upgrade existing lighting fixtiures to fixtures of higher wattage subject to payment of the following charges which provide for labor to replace the light fixture and the differential cost of the light fixture:

Lamp Size up to 150W:	$339.80 plus applicable income tax gross up
Lamp Size greater than 150W:	$430.74 plus applicable income tax gross up

TERMS OF CONTRACT
Contracts under this schedule will be made for a period of not less than one (1) year or more than five (5) years and for specified numbers and sizes of fixtures. In all cases where the customer shall authorize additional fixtures within the contract period, the number of lamps shall be increased throughout the remainder of the contract period.

In no case shall the Company be obliged to furnish lighting unless the customer shall reimburse the Company for all expenses incurred to install additional lines for such fixtures, the cost of such fixtures and accessories and the cost of the installation of the fixtures, lines and accessories.

Removal of fixtures and related facilities shall be at the direction of the customer and the customer shall reimburse the Company for all removal costs.

CREDITS
The annual charge per unit reflects an outage allowance based on normal and abnormal operating conditions.

TERMS AND CONDITIONS OF SERVICE
See Section II inclusive for Terms and Conditions of Service.

Customers requiring service under unusual conditions, or whose service requirements are different from those provided for herein may obtain such service under mutually acceptable contractual arrangements.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires on January 1, 2003, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein."

RIDER STB-STANDBY SERVICE
(Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY
This rider is available to customers having other sources of electrical energy supply, but who desire to purchase Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:
Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:
The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with Company approval as changes in the customer's load conditions warrant.

Generation Availability:
Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION
The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE
This rider imposes a Standby Service Charge at the following voltage levels:

Tariff	Transmission Stand By Rate ($/kW)	Distribution Stand By Rate ($/kW)
MGS-Secondary	$0.58	$0.09
MGS Primary	$0.52	$0.13
AGS Secondary	$0.22	$0.68
AGS Primary	$0.22	$0.57
TGS Sub Transmission	$0.22	$0.10
TGS Transmission	$0.22	$0.00

RIDER (RARC)

Regulatory Assets Recovery Charge (RARC)

Customers receiving service under Electric Rate Schedules RS, MGS, AGS, TS, TGS, DDC, SPL, and CSL and any customer taking service under special contractual arrangements.

Components of the Regulatory Assets Recovery Charge are as follows:

- Asbestos Removal
- FAS 106 Cost Recovery [Post Retirement Benefits other than Pension (PBOP)]
- Other Regulatory Assets

The Company's Regulatory Assets Recovery Charge to be effective on and after the date indicated below is $0.000283/kWh.

RIDER IIS

Infrastructure Investment Surcharge

APPLICABILITY

This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL.

This charge provides for full and timely recovery of revenue requirements associated with incremental infrastructure improvement projects approved by the NJ Board of Public Utilities.

This charge will be based on revenue requirements calculated using projected annual expenditures. The charge is adjusted on an annual basis and includes a true up for the difference between actual and forecasted costs. The difference between actual and forecasted costs is tracked on a monthly basis and interest on the over or under recovered balance is calculated monthly using the Company's current short term debt rate.

The following table provides the Infrastructure Investment Surcharge (IIS), including Sales and Use Tax, for each rate schedule in $ per kWh.

Rate Schedule	Total IIS ($ per kWh)
RS	$0.000000
MGS Secondary	$0.0000000
MGS Primary	$0.000000
AGS Secondary	$0.000000
AGS Primary	$0.000000
TGS	$0.000000
SPL/CSL	$0.000000
DDC	$0.000000

RIDER AEDR

Amortization of Excess Depreciation Reserve

AVAILABILITY
This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL.

CALCULATION OF SURCHARGE
This charge shall amortize an excess depreciation reserve that shall be amortized over 29 months beginning June 1, 2005 and is intended to expire August 31, 2013.

The charge for each Rate Schedule is as follows:

Rate Class	AEDR Credit (w/ SUT)		
RS	$	(0.002339)	$ per kWh
MGS Secondary	$	(0.001790)	$ per kWh
MGS Primary	$	(0.001869)	$ per kWh
AGS Secondary	$	(0.40)	$ per kW of billed demand
AGS Primary	$	(0.26)	$ per kW of billed demand
TGS Subtransmission	$	(0.05)	$ per kW of billed demand
TGS Transmission	$	(145.40)	$ per customer per month
SPL/CSL	$	(0.012607)	$ per kWh
DDC	$	(0.001227)	$ per kWh

Exhibit C

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Class Allocation of Distribution Revenue Requirements

Rate Schedule Specific Revenue Increase Allocation

	Rate Schedule	Total	RESIDENTIAL	MONTHLY GENERAL SERV SECONDARY	MONTHLY GENERAL SERV PRIMARY	ANNUAL GENERAL SERV SECONDARY	ANNUAL GENERAL SERV PRIMARY	TRANSMISSION GENERAL SERV SUB -TRANSMISSION	TRANSMISSION GENERAL SERV TRANSMISSION	STREET LIGHTING SERVICE	DIRECT DISTRIBUTION CONNECTION
1	Annualized Current Distribution Revenue	$ 261,325,245	$ 148,501,682	$ 48,190,719	$ 468,582	$ 38,625,374	$ 6,969,597	$ 3,203,140	$ 3,589,800	$ 11,319,763	$ 456,587
2	Rate Class Maximum Revenue Allocation Ratio		105.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	105.0%	98.0%
3	Revenue Change at Maximum Revenue Allocation Ratio	$ 45,003,668	$ 26,253,789	$ 7,951,715	$ 77,318	$ 6,373,384	$ 1,150,019	$ 528,534	$ 592,335	$ 2,001,234	$ 75,339
4	Revenue Change	$ 44,000,000	$ 25,668,279	$ 7,774,376	$ 75,594	$ 6,231,245	$ 1,124,371	$ 516,747	$ 579,125	$ 1,956,603	$ 73,659
5	Revenue Change based on Annualized Current Revenue (%)	16.8%	17.3%	16.1%	16.1%	16.1%	16.1%	16.1%	16.1%	17.3%	16.1%
6	Revenue Change Allocation Ratio		102.7%	95.8%	95.8%	95.8%	95.8%	95.8%	95.8%	102.7%	95.8%
7	Total Proposed Distribution Revenue (= 1 + 4) (Including Impact of Excess Depreciation Reserve Credit)	$ 305,325,245	$ 174,169,961	$ 55,965,096	$ 544,176	$ 44,856,619	$ 8,093,968	$ 3,719,887	$ 4,168,925	$ 13,276,366	$ 530,246

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Class Allocation of Amortization of Excess Depreciation Reserve

TABLE 1 **Allocation of Amortization Based on Per Books Cost of Service Study Results**

	TOTAL ACE RETAIL	RESIDENTIAL	MONTHLY GENERAL SERV SECONDARY	MONTHLY GENERAL SERV PRIMARY	ANNUAL GENERAL SERV SECONDARY	ANNUAL GENERAL SERV PRIMARY	TRANSMISSION GENERAL SERV SUB -TRANSMISSION	TRANSMISSION GENERAL SERV TRANSMISSION	STREET LIGHTING SERVICE	DIRECT DISTRIBUTION CONNECTION
Cost of Service Study Results (Schedule EPT-3)										
Distribution Rate Base	$ 987,112,040	$ 627,029,198	$ 127,680,543	$ 1,314,434	$ 138,185,793	$ 20,121,946	$ 4,441,213	$ 1,866,394	$ 65,546,564	$ 925,955
Excess Depreciation Reserve Revenue Requirement	$ (15,955,000)	$ (10,134,869)	$ (2,063,740)	$ (21,246)	$ (2,233,540)	$ (325,237)	$ (71,785)	$ (30,167)	$ (1,059,450)	$ (14,967)

TABLE 2 **Rate Class Amortization of Excess Depreciation Reserve (EADR) Credit**

Rate Class	Billing Determinant		AEDR Credit	AEDR Credit (w/ SUT)
RS	4,635,392,734	kWh	$ (0.002186)	$ (0.002339)
MGS Secondary	1,233,643,774	kWh	$ (0.001673)	$ (0.001790)
MGS Primary	12,164,479	kWh	$ (0.001747)	$ (0.001869)
AGS Secondary	6,096,936	kW	$ (0.37)	$ (0.40)
AGS Primary	1,337,118	kW	$ (0.24)	$ (0.26)
TGS Subtransmission	1,352,529	kW	$ (0.05)	$ (0.05)
TGS Transmission	222	customer	$ (135.89)	$ (145.40)
SPL/CSL	89,920,559	kWh	$ (0.011782)	$ (0.012607)
DDC	13,047,790	kWh	$ (0.001147)	$ (0.001227)

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule		RS
Distribution Functional Revenue Requirements Total (w/o SUT)	$	174,169,961
Proposed Customer Charge Recovery	$	16,197,261
Proposed Demand/Energy Charge Recovery	$	157,972,700
Distribution Functional Revenue Requirements Total (w/ SUT)	$	186,361,858

1	2	3	4	5	6	7	8	9	10	11	12
Blocks	**Billing Determinants**	**Current Distribution Rates (including SUT)**	**IIS**	**Current Distribution Rates (w/o SUT)**	**Calculated Rate Class Revenue under Current Distribution Rates (w/o SUT)**	**Proposed Distribution Rates (w/o SUT)**	**Winter First Block Adjustment Factor**	**Proposed Distribution Rates (w/o SUT)**	**Recovery under Proposed Distribution Rates (w/o SUT)**	**Proposed Rate (including SUT)**	**Recovery under Proposed Distribution Rates (including SUT)**
CUSTOMER	482,061	$ 2.73		$ 2.55	$ 14,751,077	$ 2.80		$ 2.80	$ 16,197,261	$ 3.00	$ 17,354,208
SUM 'First 750 KWh	1,153,197,593	$ 0.031162	$ 0.000253	$ 0.029360	$ 33,857,881	$ 0.034677		$ 0.034677	$ 39,989,433	$ 0.037104	$ 42,788,244
WIN' First 500 KWh	1,492,035,430	$ 0.031140	$ 0.000253	$ 0.029339	$ 43,774,827	$ 0.034652	$ (0.000701)	$ 0.033951	$ 50,656,095	$ 0.036328	$ 54,202,663
SUM '> 750 KWh	882,703,088	$ 0.035864	$ 0.000253	$ 0.033754	$ 29,794,760	$ 0.039867		$ 0.039867	$ 35,190,724	$ 0.042658	$ 37,654,348
WIN > 500 KWh	1,107,456,623	$ 0.025180	$ 0.000253	$ 0.023769	$ 26,323,136	$ 0.028074		$ 0.029018	$ 32,136,448	$ 0.031050	$ 34,386,528
TOTAL ENERGY	4,635,392,734				$ 133,750,605				$ 157,972,700		$ 169,031,783
TOTAL REVENUE					**$ 148,501,682**				**$ 174,169,961**		**$ 186,385,991**
											$ (24,133)

Winter First Block Adjustment

Level Winter Rate at Proposed Revenue	$	0.031850	
1st Block Movement required to Level Blocks	$	(0.002802)	= Level Winter Rate - Current First Winter Block Rate
% of Movement to 1st Block		**-8%**	= Block Movement / Current First Block Rate
Winter First Block Adjustment Factor		25%	
Proposed Winter First Block Adjustment		(0.000701)	=Required 1st Block Movement x Winter First Block Adjustment Factor

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule	**MGS SECONDARY**		
Distribution Functional Revenue Requirements Total (w/o SUT)		$ 55,965,096	
Proposed Customer Charge Recovery		$ 3,337,616	
Proposed Demand/Energy Charge Recovery		$ 52,627,479	
Demand Allocation		$ 9,018,372	17%
Energy Allocation		$ 43,609,107	83%
Distribution Functional Revenue Requirements Total (w/ SUT)		$ 59,882,652	

1	2	3	4	5	6	7	8	9	10	11	12
								PROPOSED RATE DESIGN			
BLOCK	**Billing Determinants**	**Current Distribution Rates**	**IIS**	**Current Distribution Rates (w/o SUT)**	**Calculated Rate Class Revenue under Current Distribution Rates (w/o SUT)**	**BLOCK**	**Billing Determinants**	**Proposed Distribution Rates (w/o SUT)**	**Recovery under Proposed Distribution Rates (w/o SUT)**	**Proposed Rate (including SUT)**	**Recovery under Proposed Distribution Rates (including SUT)**
CUSTOMER						CUSTOMER					
Single Phase Service	40,303	$ 5.21		$ 4.87	2,355,307	Single Phase Service	40,303	$ 4.87	$ 2,355,307	$ 5.21	$ 2,519,744
3 Phase Service	13,464	$ 6.51		$ 6.08	982,309	3 Phase Service	13,464	$ 6.08	$ 982,309	$ 6.51	$ 1,051,782
DEMAND CHARGE						DEMAND CHARGE - All kWs					
SUM > 3 KW	717,377	$ 5.02		$ 4.69	3,364,496	Summer	2,262,527	$ 1.47	$ 3,325,914	$ 1.57	$ 3,552,167
WIN > 3 KW	1,119,378	$ 4.13		$ 3.86	4,320,798	Winter	3,594,093	$ 1.21	$ 4,348,852	$ 1.29	$ 4,636,380
REACTIVE DEMAND	13,277	$ 0.40		$ 0.37	4,912	REACTIVE DEMAND	13,277	$ 0.37	$ 4,912	$ 0.40	$ 5,311
ENERGY CHARGE						ENERGY CHARGE					
SUM < 300KWh	26,967,970	$ 0.043461	$ 0.000253	$ 0.040854	1,101,749	Summer	511,468,966	$ 0.038612	$ 19,748,840	$ 0.041315	$ 21,131,340
WIN < 300 KWh	56,476,758	$ 0.043537	$ 0.000253	$ 0.040925	2,311,311	Winter	722,174,808	$ 0.034879	$ 25,188,735	$ 0.037321	$ 26,952,286
SUM NEXT 900 KWH	47,587,526	$ 0.025426	$ 0.000253	$ 0.023999	1,142,053						
WIN NEXT 900 KWh	99,002,779	$ 0.019979	$ 0.000253	$ 0.018908	1,871,945						
SUM > 1200 KWh	237,865,178	$ 0.022333	$ 0.000253	$ 0.021108	5,020,858						
WIN > 1200 KWh	344,387,570	$ 0.019979	$ 0.000253	$ 0.018908	6,511,680						
CEILING LIMIT	421,355,993	$ 0.048512	$ 0.000253	$ 0.045575	19,203,299						
TOTAL KWH	1,233,643,774										
TOTAL REVENUE					**$ 48,190,719**				**$ 55,954,870**		**$ 59,849,009**

Proposed Demand Charge Rate Design

Current Demand Related Revenue	$ 7,685,294		
Current Annual Average Demand Rate	$ 4.18		Seasonal Rate Ratios
Current Summer Demand Rate	$ 4.69		1.122
Current Winter Demand Rate	$ 3.86		0.923
Proposed Demand Related Revenue	$ 7,685,294		
Average Proposed Demand Rate	$ 1.31		
Proposed Summer Demand Rate	$ 1.47	maintain same summer to annual rate ratio	
Proposed Winter Demand Rate	$ 1.21	maintain same winter to annual rate ratio	

Proposed Volumetric Charge Rate Design

	Current	Seasonal Rate Ratios	Proposed
Volumetric Related Revenue	$ 37,162,896		$ 44,937,272
Total kWh	1,233,643,774		1,233,643,774
Average Rate			
Annual	$ 0.030124		$ 0.036426
Summer	$ 0.031940	1.060	$ 0.038612
Winter	$ 0.028839	0.957	$ 0.034879

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule	**MGS PRIMARY**		
Distribution Functional Revenue Requirements Total (w/o SUT)	$	544,176	
Proposed Customer Charge Recovery	$	3,429	
Proposed Demand/Energy Charge Recovery	$	540,747	
Demand Allocation	$	97,309	18%
Energy Allocation	$	443,438	82%
Distribution Functional Revenue Requirements Total (w/ SUT)	$	582,269	

								PROPOSED RATE DESIGN			
1	2	3		4	5	6	7	8	9	10	11
BLOCK	**Billing Determinants**	**Current Distribution Rates**	**IIS**	**Current Distribution Rates (w/o SUT)**	**Calculated Rate Class Revenue under Current Distribution Rates (w/o SUT)**	**BLOCK**	**Billing Determinants**	**Proposed Distribution Rates (w/o SUT)**	**Recovery under Proposed Distribution Rates (w/o SUT)**	**Proposed Rate (including SUT)**	**Recovery under Proposed Distribution Rates (including SUT)**
CUSTOMER						CUSTOMER					
Single Phase Service	17	$ 5.21		$ 4.87	$ 979	Single Phase Service	17	$ 4.87	$ 979	$ 5.21	$ 1,047
3 Phase Service	34	$ 6.51		$ 6.08	$ 2,450	3 Phase Service	34	$ 6.08	$ 2,450	$ 6.51	$ 2,624
DEMAND CHARGE						DEMAND CHARGE - All kWs					
SUM > 3 KW	9,052	$ 5.21		$ 4.87	$ 44,082	Summer	42,175	$ 1.30	$ 54,827	$ 1.39	$ 58,623
WIN > 3 KW	13,307	$ 4.28		$ 4.00	$ 53,227	Winter	41,892	$ 1.01	$ 42,311	$ 1.08	$ 45,243
REACTIVE DEMAND	4,698	$ 0.40		$ 0.37	$ 1,738	REACTIVE DEMAND	4,698	$ 0.37	$ 1,738	$ 0.40	$ 1,879
ENERGY CHARGE						ENERGY CHARGE					
SUM < 300KWh	23,338	$ 0.044831	$ 0.000245	$ 0.042127	$ 983	Summer	5,910,545	$ 0.036856	$ 217,839	$ 0.039436	$ 233,088
WIN < 300 KWh	62,232	$ 0.044908	$ 0.000245	$ 0.042199	$ 2,626	Winter	6,253,934	$ 0.035795	$ 223,860	$ 0.038301	$ 239,532
SUM NEXT 900 KWH	64,000	$ 0.026505	$ 0.000245	$ 0.025000	$ 1,600						
WIN NEXT 900 KWh	161,165	$ 0.020968	$ 0.000245	$ 0.019825	$ 3,195						
SUM > 1200 KWh	3,831,406	$ 0.023361	$ 0.000245	$ 0.022062	$ 84,528						
WIN > 1200 KWh	3,810,573	$ 0.020968	$ 0.000245	$ 0.019825	$ 75,545						
CEILING LIMIT	4,211,765	$ 0.049963	$ 0.000245	$ 0.046923	$ 197,629						
TOTAL KWH	12,164,479										
TOTAL REVENUE					**$ 468,582**				**$ 544,003**		**$ 582,036**
									$ 173		$ 233

Proposed Demand Charge Rate Design

Current Demand Related Revenue	$	97,309		
Current Annual Average Demand Rate	$	4.35		Seasonal Rate Ratios
Current Summer Demand Rate	$	4.87		1.120
Current Winter Demand Rate	$	4.00		0.920
Proposed Demand Related Revenue	$	97,309		
Average Proposed Demand Rate	$	1.16		
Proposed Summer Demand Rate	$	1.30	maintain same summer to annual rate ratio	
Proposed Winter Demand Rate	$	1.01	maintain same winter to annual rate ratio	

Proposed Volumetric Charge Rate Design

		Current	Seasonal Rate Ratios		Proposed
Volumetric Related Revenue	$	366,106		$	441,700
Total kWh		12,164,479			12,164,479
Average Rate					
Annual	$	0.030096		$	0.036311
Summer	$	0.030551	1.015	$	0.036856
Winter	$	0.029667	0.986	$	0.035795

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule	**AGS SECONDARY**		
Distribution Functional Revenue Requirements Total (w/o SUT)		$	44,856,619
Proposed Customer Charge Recovery		$	6,176,256
Proposed Demand/Energy Charge Recovery		$	38,680,363
Distribution Functional Revenue Requirements Total (w/ SUT)		$	47,996,582

							PROPOSED RATE DESIGN			
1	2	3	4	5	6	7	8	9	10	11
BLOCK	**Billing Determinants**	**Current Distribution Rates**	**Current Distribution Rates (w/o SUT)**	**Calculated Rate Class Revenue under Current Distribution Rates (w/o SUT)**	**BLOCK**	**Billing Determinants**	**Preliminary Distribution Rate (w/o SUT)**	**Recovery under Preliminary Distribution Rates (w/o SUT)**	**Proposed Rate (including SUT)**	**Recovery under Proposed Distribution Rates (including SUT)**
CUSTOMER	3,612	$ 101.34	$ 94.71	$ 4,105,205	CUSTOMER	3,612	$ 142.49	$ 6,176,229	$ 152.46	$ 6,608,379
DEMAND CHARGE	6,096,936	$ 5.93	$ 5.54	$ 33,777,025	DEMAND CHARGE	6,096,936	$ 6.30	$ 38,410,697	$ 6.74	$ 41,093,349
REACTIVE DEMAND	520,240	$ 0.51	$ 0.48	$ 249,715	REACTIVE DEMAND	520,240	$ 0.48	$ 249,715	$ 0.51	$ 265,322.35
IIS	2,090,797,811	$ 0.000253	$ 0.000236	$ 493,428						
TOTAL REVENUE				**$ 38,625,374**				**$ 44,836,641**		**$ 47,967,050**

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule	**AGS PRIMARY**	
Distribution Functional Revenue Requirements Total (w/o SUT)	$	8,093,968
Proposed Customer Charge Recovery	$	950,082
Proposed Demand/Energy Charge Recovery	$	7,143,886
Distribution Functional Revenue Requirements Total (w/ SUT)	$	8,660,546

							PROPOSED RATE DESIGN			
1	2	3	4	5	6	7	8	9	10	11
BLOCK	**Billing Determinants**	**Current Distribution Rates**	**Current Distribution Rates (w/o SUT)**	**Calculated Rate Class Revenue under Current Distribution Rates (w/o SUT) (See Note 1)**	**BLOCK**	**Billing Determinants**	**Preliminary Distribution Rate (w/o SUT)**	**Recovery under Preliminary Distribution Rates (w/o SUT)**	**Proposed Rate (including SUT)**	**Recovery under Proposed Distribution Rates (including SUT)**
CUSTOMER	121	$ 101.34	$ 94.71	$ 137,898	CUSTOMER	121	$ 652.53	$ 950,084	$ 698.21	$ 1,016,594
DEMAND CHARGE	1,337,118	$ 5.26	$ 4.92	$ 6,578,622	DEMAND CHARGE	1,337,118	$ 5.26	$ 7,033,242	$ 5.63	$ 7,527,976
REACTIVE DEMAND	290,822	$ 0.42	$ 0.39	$ 113,420	REACTIVE DEMAND	290,822	$ 0.39	$ 113,420	$ 0.42	$ 122,145.03
IIS	609,853,224	$ 0.000245	$ 0.000229	$ 139,656						
TOTAL REVENUE				**$ 6,969,597**				**$ 8,096,747**		**$ 8,666,715**

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule	**TGS SUB TRANSMISSION**	
Distribution Functional Revenue Requirements Total (w/o SUT)	$	3,719,887
Proposed Customer Charge Recovery	$	2,466,947
Proposed Demand/Energy Charge Recovery	$	1,252,940
Distribution Functional Revenue Requirements Total (w/ SUT)	$	3,980,279

								PROPOSED RATE DESIGN		
1	2	3	4	5	6	7	8	9	10	11
BLOCK	**Billing Determinants**	**Current Distribution Rates**	**Current Distribution Rates (w/o SUT)**	**Calculated Rate Class Revenue under Current Distribution Rates (w/o SUT) (See Note 1)**	**BLOCK**	**Billing Determinants**	**Preliminary Distribution Rate (w/o SUT)**	**Recovery under Preliminary Distribution Rates (w/o SUT)**	**Proposed Rate (including SUT)**	**Recovery under Proposed Distribution Rates (including SUT)**
CUSTOMER	38	$ 96.92	$ 90.58	$ 41,033	CUSTOMER	38	$ 5,445.80	$ 2,466,947	$ 5,827.01	$ 2,639,636
DEMAND CHARGE	1,352,529	$ 2.20	$ 2.06	$ 2,786,211	DEMAND CHARGE	1,352,529	$ 0.88	$ 1,190,226	$ 0.94	$ 1,271,378
REACTIVE DEMAND	406,063	$ 0.17	$ 0.16	$ 64,970	REACTIVE DEMAND	406,063	$ 0.16	$ 64,970	$ 0.17	$ 69,030.75
IIS	1,388,064,576	$ 0.000240	$ 0.000224	$ 310,926						
TOTAL REVENUE				**$ 3,203,140**				**$ 3,722,143**		**$ 3,980,044**

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule	**TGS TRANSMISSION**	
Distribution Functional Revenue Requirements Total (w/o SUT)	$	4,168,925
Proposed Customer Charge Recovery	$	4,168,925
Proposed Demand/Energy Charge Recovery	$	-
Distribution Functional Revenue Requirements Total (w/ SUT)	$	4,460,750

							PROPOSED RATE DESIGN			
1	2	3	4	5	6	7	8	9	10	11
BLOCK	**Billing Determinants**	**Current Distribution Rates**	**Current Distribution Rates (w/o SUT)**	**Calculated Rate Class Revenue under Current Distribution Rates (w/o SUT) (See Note 1)**	**BLOCK**	**Billing Determinants**	**Preliminary Distribution Rate (w/o SUT)**	**Recovery under Preliminary Distribution Rates (w/o SUT)**	**Proposed Rate (including SUT)**	**Recovery under Proposed Distribution Rates (including SUT)**
CUSTOMER	19	$ 96.92	$ 90.58	$ 20,109	CUSTOMER	19	$ 18,778.94	$ 4,168,925	$ 20,093.47	$ 4,460,750
DEMAND CHARGE	1,392,324	$ 2.20	$ 2.06	$ 2,868,187						
REACTIVE DEMAND	1,177,050	$ 0.17	$ 0.16	$ 188,328						
IIS	1,388,064,576	$ 0.000240	$ 0.000224	$ 310,926						
STAND BY	963,097	$ 0.22	$ 0.21	$ 202,250						
TOTAL REVENUE				**$ 3,589,800**				**$ 4,168,925**		**$ 4,460,750**

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule **SPL CSL DDC**

Distribution Functional Revenue Requirements Total		w/o SUT	w/ SUT
	SPL	$ 11,543,439	$ 12,351,480
	CSL	$ 1,732,927	$ 1,854,231
	DDC	$ 530,246	$ 567,364

TARIFF	BLOCKS	Billing Determinants	Current Distribution Rates Equip/Cust	Current Distribution Rates Energy	Current Distribution Rates (w/o Tax) Equip/Cust	Current Distribution Rates (w/o Tax) Energy	Revenue under Current Distribution Rates (w/o SUT)	Proposed Distribution Rates Equip/Cust	Proposed Distribution Rates Energy	Proposed Distribution Rates Total	Recovery under Proposed Distribution Rates (w/o SUT)	Distribution Rates (including SUT) Equip/Cust	Distribution Rates (including SUT) Energy	Distribution Rates (including SUT) Total	Recovery under Proposed Distribution Rates (w/ SUT)
SPL	1000 LUMENS-INC	1,050	$ 3.69	$ 0.21	$ 3.45	0.20	$ 45,990	$ 4.05	$ 0.24	$ 4.29	$ 54,054	$ 4.33	$ 0.26	$ 4.59	$ 57,834
	2500 LUMENS-INC	170	$ 6.39	$ 0.41	$ 5.97	0.38	$ 12,954	$ 7.02	$ 0.45	$ 7.47	$ 15,239	$ 7.51	$ 0.48	$ 7.99	$ 16,300
	4000 LUMENS-INC	28	$ 8.81	$ 0.66	$ 8.24	0.62	$ 2,977	$ 9.68	$ 0.73	$ 10.41	$ 3,498	$ 10.36	$ 0.78	$ 11.14	$ 3,743
	6000 LUMENS-INC	10	$ 11.77	$ 0.91	$ 11.00	0.85	$ 1,422	$ 12.93	$ 1.00	$ 13.93	$ 1,672	$ 13.84	$ 1.07	$ 14.91	$ 1,789
	3500 LUMENS-MV	7,638	$ 6.32	$ 0.26	$ 5.91	0.24	$ 563,684	$ 6.94	$ 0.28	$ 7.22	$ 661,756	$ 7.43	$ 0.30	$ 7.73	$ 708,501
	6800 LUMENS-MV	1,326	$ 8.39	$ 0.42	$ 7.84	0.39	$ 130,956	$ 9.21	$ 0.46	$ 9.67	$ 153,869	$ 9.85	$ 0.49	$ 10.34	$ 164,530
	11000 LUMENS-MV	448	$ 10.60	$ 0.58	$ 9.90	0.54	$ 56,125	$ 11.63	$ 0.63	$ 12.26	$ 65,910	$ 12.44	$ 0.67	$ 13.11	$ 70,479
	20000 LUMENS-MV	338	$ 15.17	$ 0.92	$ 14.18	0.86	$ 61,002	$ 16.66	$ 1.01	$ 17.67	$ 71,670	$ 17.83	$ 1.08	$ 18.91	$ 76,699
	35000 LUMENS-MV	2	$ 24.09	$ 1.59	$ 22.52	1.49	$ 576	$ 26.46	$ 1.75	$ 28.21	$ 677	$ 28.31	$ 1.87	$ 30.18	$ 724
	55000 LUMENS-MV	39	$ 32.71	$ 2.24	$ 30.57	2.09	$ 15,285	$ 35.92	$ 2.46	$ 38.38	$ 17,962	$ 38.43	$ 2.63	$ 41.06	$ 19,216
	11000 LUMENS-HPS	3,617	$ 7.71	$ 0.37	$ 7.20	0.34	$ 327,266	$ 8.46	$ 0.40	$ 8.86	$ 384,559	$ 9.05	$ 0.43	$ 9.48	$ 411,470
	30000 LUMENS-HPS	642	$ 14.21	$ 0.85	$ 13.28	0.80	$ 108,472	$ 15.60	$ 0.94	$ 16.54	$ 127,424	$ 16.69	$ 1.01	$ 17.70	$ 136,361
	50 WATT-HPS-COBRAHD-OVHD	20,394	$ 7.05	$ 0.13	$ 6.59	0.12	$ 1,642,150	$ 7.74	$ 0.14	$ 7.88	$ 1,928,486	$ 8.28	$ 0.15	$ 8.43	$ 2,063,089
	70 WATT-HPS-COBRAHD-OVHD	10,128	$ 7.26	$ 0.17	$ 6.78	0.16	$ 843,459	$ 7.97	$ 0.19	$ 8.16	$ 991,733	$ 8.53	$ 0.20	$ 8.73	$ 1,061,008
	100 WATT-HPS-COBRAHD-OVHD	9,284	$ 7.58	$ 0.24	$ 7.09	0.23	$ 815,488	$ 8.33	$ 0.27	$ 8.60	$ 958,087	$ 8.91	$ 0.29	$ 9.20	$ 1,024,931
	150 WATT-HPS-COBRAHD-OVHD	6,933	$ 8.19	$ 0.35	$ 7.65	0.32	$ 663,099	$ 8.99	$ 0.38	$ 9.37	$ 779,579	$ 9.62	$ 0.41	$ 10.03	$ 834,490
	250 WATT-HPS-COBRAHD-OVHD	5	$ 11.51	$ 0.60	$ 10.76	0.56	$ 642	$ 12.64	$ 0.66	$ 13.30	$ 755	$ 13.52	$ 0.71	$ 14.23	$ 808
	400 WATT-HPS-COBRAHD-OVHD	1,677	$ 13.09	$ 0.93	$ 12.24	0.87	$ 263,758	$ 14.38	$ 1.02	$ 15.40	$ 309,830	$ 15.39	$ 1.09	$ 16.48	$ 331,558
	150 WATT-HPS-SHOEBOX-OVHD	86	$ 10.07	$ 0.35	$ 9.41	0.32	$ 10,078	$ 11.06	$ 0.38	$ 11.44	$ 11,849	$ 11.83	$ 0.41	$ 12.24	$ 12,677
	250 WATT-HPS-SHOEBOX-OVHD	2,588	$ 12.92	$ 0.60	$ 12.07	0.57	$ 392,572	$ 14.18	$ 0.67	$ 14.85	$ 461,210	$ 15.17	$ 0.72	$ 15.89	$ 493,510
	400 WATT-HPS-SHOEBOX-OVHD	583	$ 14.70	$ 0.94	$ 13.74	0.87	$ 102,194	$ 16.15	$ 1.02	$ 17.17	$ 120,100	$ 17.28	$ 1.09	$ 18.37	$ 128,494
	50 WATT-HPS-POSTTOP-OVHD	134	$ 7.84	$ 0.13	$ 7.33	0.12	$ 11,944	$ 8.61	$ 0.14	$ 8.75	$ 14,029	$ 9.21	$ 0.15	$ 9.36	$ 15,007
	100 WATT-HPS-POSTTOP-OVHD	396	$ 8.43	$ 0.24	$ 7.88	0.23	$ 38,547	$ 9.26	$ 0.27	$ 9.53	$ 45,296	$ 9.91	$ 0.29	$ 10.20	$ 48,481
	150 WATT-HPS-POSTTOP-OVHD	6,631	$ 9.89	$ 0.35	$ 9.25	0.32	$ 761,459	$ 10.87	$ 0.38	$ 11.25	$ 895,132	$ 11.63	$ 0.41	$ 12.04	$ 957,990
	150 WATT-HPS-FLOOD-OVHD	1,591	$ 8.00	$ 0.35	$ 7.48	0.32	$ 148,959	$ 8.79	$ 0.38	$ 9.17	$ 175,122	$ 9.41	$ 0.41	$ 9.82	$ 187,535
	250 WATT-HPS-FLOOD-OVHD	2,563	$ 9.97	$ 0.60	$ 9.32	0.56	$ 303,908	$ 10.95	$ 0.66	$ 11.61	$ 357,123	$ 11.72	$ 0.71	$ 12.43	$ 382,346
	400 WATT-HPS-FLOOD-OVHD	3,918	$ 12.60	$ 0.93	$ 11.78	0.87	$ 594,798	$ 13.84	$ 1.02	$ 14.86	$ 698,711	$ 14.81	$ 1.09	$ 15.90	$ 747,612
	400 WATT-MH-FLOOD-OVHD	857	$ 15.69	$ 0.94	$ 14.66	0.88	$ 159,851	$ 17.23	$ 1.03	$ 18.26	$ 187,830	$ 18.44	$ 1.10	$ 19.54	$ 200,997
	1000 WATT-MH-FLOOD-OVHD	641	$ 26.19	$ 2.18	$ 24.48	2.04	$ 203,938	$ 28.77	$ 2.40	$ 31.17	$ 239,697	$ 30.78	$ 2.57	$ 33.35	$ 256,461
	50 WATT-HPS-COBRAHD-UGRD	218	$ 10.92	$ 0.13	$ 10.20	0.12	$ 26,942	$ 11.99	$ 0.14	$ 12.13	$ 31,667	$ 12.83	$ 0.15	$ 12.98	$ 33,886
	70 WATT-HPS-COBRAHD-UGRD	404	$ 11.12	$ 0.17	$ 10.40	0.16	$ 51,241	$ 12.22	$ 0.19	$ 12.41	$ 60,218	$ 13.08	$ 0.20	$ 13.28	$ 64,439
	100 WATT-HPS-COBRAHD-UGRD	259	$ 11.45	$ 0.24	$ 10.70	0.23	$ 33,962	$ 12.57	$ 0.27	$ 12.84	$ 39,897	$ 13.45	$ 0.29	$ 13.74	$ 42,693
	150 WATT-HPS-COBRAHD-UGRD	549	$ 12.05	$ 0.35	$ 11.27	0.32	$ 76,301	$ 13.24	$ 0.38	$ 13.62	$ 89,665	$ 14.17	$ 0.41	$ 14.58	$ 95,985
	250 WATT-HPS-COBRAHD-UGRD	199	$ 14.42	$ 0.61	$ 13.47	0.57	$ 33,466	$ 15.83	$ 0.67	$ 16.50	$ 39,330	$ 16.94	$ 0.72	$ 17.66	$ 42,095
	400 WATT-HPS-COBRAHD-UGRD	280	$ 15.99	$ 0.94	$ 14.94	0.88	$ 53,196	$ 17.56	$ 1.03	$ 18.59	$ 62,511	$ 18.79	$ 1.10	$ 19.89	$ 66,882
	150 WATT-HPS-SHOEBOX-UGRD	519	$ 13.95	$ 0.35	$ 13.04	0.33	$ 83,276	$ 15.32	$ 0.39	$ 15.71	$ 97,851	$ 16.39	$ 0.42	$ 16.81	$ 104,703
	250 WATT-HPS-SHOEBOX-UGRD	450	$ 16.78	$ 0.61	$ 15.68	0.57	$ 87,843	$ 18.42	$ 0.67	$ 19.09	$ 103,195	$ 19.71	$ 0.72	$ 20.43	$ 110,438
	400 WATT-HPS-SHOEBOX-UGRD	589	$ 18.56	$ 0.94	$ 17.35	0.88	$ 128,808	$ 20.39	$ 1.03	$ 21.42	$ 151,347	$ 21.82	$ 1.10	$ 22.92	$ 161,946
	50 WATT-HPS-POSTTOP-UGRD	757	$ 9.65	$ 0.13	$ 9.02	0.12	$ 82,995	$ 10.60	$ 0.14	$ 10.74	$ 97,524	$ 11.34	$ 0.15	$ 11.49	$ 104,334
	100 WATT-HPS-POSTTOP-UGRD	2,484	$ 10.26	$ 0.24	$ 9.59	0.23	$ 292,728	$ 11.27	$ 0.27	$ 11.54	$ 344,000	$ 12.06	$ 0.29	$ 12.35	$ 368,145
	150 WATT-HPS-POSTTOP-UGRD	901	$ 13.99	$ 0.35	$ 13.07	0.33	$ 144,873	$ 15.36	$ 0.39	$ 15.75	$ 170,279	$ 16.44	$ 0.42	$ 16.86	$ 182,280
	150 WATT-HPS-FLOOD-UGRD	105	$ 12.73	$ 0.35	$ 11.90	0.33	$ 15,443	$ 13.98	$ 0.39	$ 14.37	$ 18,146	$ 14.96	$ 0.42	$ 15.38	$ 19,421
	250 WATT-HPS-FLOOD-UGRD	232	$ 14.69	$ 0.61	$ 13.73	0.57	$ 39,767	$ 16.13	$ 0.67	$ 16.80	$ 46,719	$ 17.26	$ 0.72	$ 17.98	$ 50,000
	400 WATT-HPS-FLOOD-UGRD	560	$ 16.48	$ 0.94	$ 15.40	0.88	$ 109,486	$ 18.10	$ 1.03	$ 19.13	$ 128,653	$ 19.37	$ 1.10	$ 20.47	$ 137,665
	400 WATT-MH-FLOOD-UGRD	110	$ 19.66	$ 0.94	$ 18.37	0.88	$ 25,400	$ 21.59	$ 1.03	$ 22.62	$ 29,847	$ 23.10	$ 1.10	$ 24.20	$ 31,932
	1000 WATT-MH-FLOOD-UGRD	135	$ 30.16	$ 2.19	$ 28.18	2.04	$ 48,879	$ 33.11	$ 2.40	$ 35.51	$ 57,436	$ 35.43	$ 2.57	$ 38.00	$ 61,463
	ORN STANDARDS-BEFORE 1-17-86	2,868	$ 6.39	$ -	$ 5.97	-	$ 205,490	$ 7.02	$ -	$ 7.02	$ 241,632	$ 7.51	$ -	$ 7.51	$ 258,498
	NON-ORN STANDARDS-AFTER 1-17-86	1	$ 9.34	$ -	$ 8.73	-	$ 124	$ 10.26	$ -	$ 10.26	$ 146	$ 10.98	$ -	$ 10.98	$ 156
	POSTS		$ 2.24	$ -	$ 2.09	-	$ -	$ 2.46	$ -	$ 2.46	$ -	$ 2.63	$ -	$ 2.63	$ -
	Total	95,338					$ 9,823,775				$ 11,542,918				$ 12,351,601
CSL	HPS50	16,031	$ -	$ 3.03	$ -	2.83	$ 544,408	$ -	$ 3.33	$ 3.33	$ 640,593	$ -	$ 3.56	$ 3.56	$ 684,838
	HPS70	7,117	$ -	$ 3.31	$ -	3.09	$ 263,894	$ -	$ 3.63	$ 3.63	$ 310,012	$ -	$ 3.88	$ 3.88	$ 331,362
	HPS100	7,818	$ -	$ 3.70	$ -	3.45	$ 323,654	$ -	$ 4.05	$ 4.05	$ 379,942	$ -	$ 4.33	$ 4.33	$ 406,210
	HPS150	4,508	$ -	$ 4.40	$ -	4.12	$ 222,881	$ -	$ 4.84	$ 4.84	$ 261,830	$ -	$ 5.18	$ 5.18	$ 280,224
	HPS250	994	$ -	$ 6.01	$ -	5.62	$ 67,035	$ -	$ 6.60	$ 6.60	$ 78,725	$ -	$ 7.06	$ 7.06	$ 84,212
	HPS400	592	$ -	$ 7.96	$ -	7.44	$ 52,895	$ -	$ 8.74	$ 8.74	$ 62,137	$ -	$ 9.35	$ 9.35	$ 66,474
	STANDARDS	-	$ -	$ 6.39	$ -	5.97	$ -	$ -	$ 7.02	$ 7.02	$ -	$ -	$ 7.51	$ 7.51	$ -
	Total	37,060					$ 1,474,767				$ 1,733,239				$ 1,853,319
	IIS	89,920,559		$ 0.000253		$ 0.000236	$ 21,221								
DDC	Service and Demand (per day per connection)	982,945	$ 0.360761		$ 0.337160		$ 331,410	$ 0.147228			$ 144,717	$ 0.157534			$ 154,847
	Energy (per day for each kW of effective load)	543,658	$ 1.737648		$ 1.623970		$ 882,884	$ 0.709140			$ 385,530	$ 0.758780			$ 412,517
							$ 1,214,293.88				$ 530,247				$ 567,364
	IIS	13,047,790		$ 0.000253		$ 0.000236	$ 3,079								

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet
Stand By Rate

	Demand Rates ($/kW)		Standby Rates ($/kW)		Distribution Standby
Rate Schedule		**Distribution**		**Distribution**	Factor
MGS Secondary	$	1.40	$	0.09	0.06097561
MGS Primary	$	1.24	$	0.13	0.101604278
AGS Secondary	$	6.74	$	0.68	0.101604278
AGS Primary	$	5.63	$	0.57	0.101604278
TGS - Sub Transmission	$	0.94	$	0.10	0.101604278
TGS Transmission	$	-	$	-	

PSE&G
Non-Objection Letter

Martin C. Rothfelder
Associate General Regulatory Counsel

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-6479 fax: 973-430-5983
email: martin.rothfelder@pseg.com

October 12, 2012

In the Matter of the Petition of Atlantic City Electric Company
for Approval of Amendments to its Tariff to Provide for an
Increase in Rates and Charges for Electric Service Pursuant to
N.J.S.A. 48:2-21 and *N.J.S.A.* 48:2-21.1
and for Other Appropriate Relief

OAL Docket No. PUC 09929-2011
BPU Docket No. ER11080469

VIA E-MAIL AND REGULAR MAIL

Honorable Irene Jones
Administrative Law Judge
Office of Administrative Law
33 Washington Avenue
Newark, New Jersey 07102

Dear Judge Jones:

This letter, of which 3 additional copies are enclosed, is to advise that Public Service Electric and Gas Company ("PSE&G"), a participant in this proceeding, has no objection to the settlement between the Parties which was provided to PSE&G via e-mail by Atlantic City Electric Company counsel dated October 12, 2012 at 1:09 pm and which we anticipate will be filed shortly.

Copies of this letter are being forwarded this date via electronic mail to all persons whose name appear on the attached distribution list.

Respectfully submitted,

Martin C. Rothfelder

C Attached Service List (E-Mail Only)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ATLANTIC CITY ELECTRIC RATE CASE - 2011
BPU DOCKET NO. ER11080469

BPU

Alice Bator, Bureau Chief
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Floor
P.O. Box 359
Trenton, NJ 08625-0350
PHONE: (609) 943-5805
FAX: (___) ___-____
alice.bator@bpu.state.nj.us

Mark Beyer, Chief Economist
Board of Public Utilities
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-2637
FAX: (___) ___-____
mark.beyer@bpu.state.nj.us

Rene Demuynck
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
PO Box 350
Trenton, NJ 08625-0350
PHONE: (609) 777-3337
FAX: (___) ___-____
rene.demuynck@bpu.state.nj.us

Eloisa Flores
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08626-0350
PHONE: (609) 292-4172
FAX: (___) ___-____
eloisa.flores@bpu.state.nj.us

Julie Ford-Williams, Supervisor
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (___) ___-____
FAX: (___) ___-____
julie.ford@bpu.state.nj.us

Jacqueline Galka, Bureau Chief
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 984-4657
FAX: (___) ___-____
jackie.galka@bpu.state.nj.us

Kristi Izzo, Secretary
Board of Public Utilities
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-1599
FAX: (___) ___-____
kristi.izzo@bpu.state.nj.us

Son Lin Lai
Board of Puiblic Utilities
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-2098
FAX: (___) ___-____
son-lin.lai@bpu.state.nj.us

Christine Lin
Board of Public Utilities
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-2956
FAX: (___) ___-____
christine.lin@bpu.state.nj.us

Jerome May, Director
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-3960
FAX: (___) ___-____
Jerome.may@bpu.state.nj.us

Jacqueline O'Grady
Board of Public Utilities
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-2947
FAX: (___) ___-____
jackie.ogrady@bpu.state.nj.us

Andrea Reid
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-4518
FAX: (___) ___-____
andrea.reid@bpu.state.nj.us

Henry Rich
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 341-5760
FAX: (___) ___-____
henry.rich@bpu.state.nj.us

Robert Schultheis
Board of Public Utilities
Division of Energy
44 South Clinton Ave., 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (___) ___-____
FAX: (___) ___-____
robert.schultheis@bpu.state.nj.us

Scott Sumliner
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-4519
FAX: (___) ___-____
scott.sumliner@bpu.state.nj.us

Nnajindu Ugoji
Board of Public Utilities
Division of Energy
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 777-1694
FAX: (___) ___-____
Nnajindu.ugoji@bpu.state.nj.us

Robert Wojciak
Board of Public Utilities
44 South Clinton Avenue, 9th Flr.
P.O. Box 350
Trenton, NJ 08625-0350
PHONE: (609) 292-2951
FAX: (___) ___-____
robert.wojciak@bpu.state.nj.us

DAG

Jenique Jones
NJ Dept. of Law & Public Safety
Division of Law
124 Halsey Street, 5th Flr.
PO Box 45029
Newark, NJ 07101
PHONE: (973) 648-7159
FAX: (973) 648-3555
jenique.jones@dol.lps.state.nj.us

Babette Tenzer, DAG
NJ Dept. of Law & Public Safety
Division of Law
124 Halsey Street, 5th Flr.
PO Box 45029
Newark, NJ 07101
PHONE: (973) 648-7811
FAX: (973) 648-3555
babette.tenzer@dol.lps.state.nj.us

Caroline Vachier, DAG, Assistant Section
Chief, Deputy Attorney General
NJ Dept. of Law & Public Safety
Division of Law
124 Halsey Street, 5th Flr.
P.O. Box 45029
Newark, NJ 07101
PHONE: (973) 648-3709
FAX: (973) 648-3555
caroline.vachier@dol.lps.state.nj.us

RATE COUNSEL

Stefanie A. Brand, Director
The 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

Paul Flanagan, Litigation Manag
The Division of Rate Counsel
31 Clinton Street - 11th Floor
P.O. Box 46005
Newark, NJ 07101
PHONE: (973) 648-2690
FAX: (973) 642-1047
pflanagan@rpa.state.nj.us

Ami Morita
The Division of Rate Counsel
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, Esq.
Division of 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

ATLANTIC CITY ELECTRIC

Nicholas W. Mattia (ACE)
Dickstein Shapiro LLP
1825 Eye Street, NW
Washington, DC 20006-5304
PHONE: (202) 420-3035
FAX: (___) ___-____
mattian@dicksteinshapiro.com

Philip J. Passanante, Assistant Ge
Counsel
Atlantic City Electric Co. - 89KS
800 King Street, 5th Floor
PO Box 231
Wilmington, DE 19899-0231
PHONE: (302) 429-3105
FAX: (302) 429-3801
philip.passanante@pepcoholding

Roger E. Pedersen, Manager, NJ
Regulatory Affairs
Atlantic City Electric Co. - 63MI
5100 Harding Highway
Mays Landing, NJ 08330
PHONE: (609) 625-5820
FAX: (609) 625-5838
roger.pedersen@pepcoholdings.c

WALMART

Linda Evers
STEVENS & LEE
111 N. Sixth Street
PO Box 679
Reading, PA 19603
PHONE: (___) ___-____
FAX: (___) ___-____
lre@stevenslee.com

Michael A. Gruin, Esq.
Stevens & Lee
17 North Second Street, 16th Flr.
Harrisburg, PA 17101
PHONE: (717) 255-7365
FAX: (610) 988-0852
mag@stevenslee.com

PSE&G

Connie E. Lembo
PSEG Services Corporation
80 Park Plaza, T-05
Newark, NJ 07102
PHONE: (973) 430-6273
FAX: (973) 430-5983
constance.lembo@pseg.com

Martin C. Rothfelder (PS), Associate
General Reg Counsel
PSEG Service Company
80 Park Plaza, T-5
Newark, NJ 07102
PHONE: (973) 430-6479
FAX: (973) 430-5983
martin.rothfelder@pseg.com