R00973953
PECO Filing Application
Phila 10/14,15/14/97.
E. Holbert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF QUALIFIED RATE ORDER
UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

VOLUME I

January 22, 1997

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF QUALIFIED RATE ORDER
UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

January 22, 1997

Thomas P. Hill, Jr.
Vice President and Controller

PECO ENERGY

PECO Energy Company
2301 Market Street
PO Box 8699
Philadelphia, PA 19101-8699
215 841 5802

January 22, 1997

Mr. John G. Alford, Secretary
Pennsylvania Public Utility Commission
North Office Building - P. O. Box 3265
Harrisburg, PA 17105-3265

Subject: Application Of PECO Energy Company For Issuance Of A Qualified Rate Order Under Sections 2808 and 2812 Of The Public Utility Code

Dear Mr. Alford:

In conformance with Sections 2808 and 2812 of the Pennsylvania Public Utility Code, PECO Energy Company submits an original and eight copies of the following in its request for the issuance of a Qualified Rate Order:

1. Application of PECO Energy Company For Issuance Of A Qualified Rate Order Under Sections 2808 and 2812 of the Public Utility Code
2. Exhibit 1-Proposed Form of Order
3. Exhibit 2-September 30, 1996 Balance Sheet, Pro Forma Balance Sheet and Proposed Journal Entries
4. Exhibit 3-September 30, 1996 Income Statement and Pro Forma Income Statement
5. Exhibit 4-Securitization Transaction Schematic
6. Exhibit 5-Testimony and Exhibits as Listed Below:
   - Statement 1 Direct Testimony of T. P. Hill, Jr.
   - Statement 2 Direct Testimony of A. B. Cohn
   - Statement 3 Direct Testimony of S. R. Xander
   - Statement 4 Direct Testimony of J. B. Mitchell
   - Statement 5 Direct Testimony of H. L. Hiller
   - Statement 6 Direct Testimony of J. J. Gillen
   - Statement 7 Direct Testimony of J. F. Bustard
   - Statement 8 Direct Testimony of B. S. Venkateshwara
   - Statement 9 Direct Testimony of W. H. Hieronymus
7. Exhibit 6-Supplement No. 11 to Tariff Electric-Pa.P.U.C. No. 2
8. Exhibit 7-Responses to Pre-Filing Guidelines
9. Exhibit 8-Form of Notice

Also, attached to this letter is a Certificate of Service providing a listing of the parties which have been served on this date by first class mail with copies of this filing or notice thereof.

Also enclosed is the required filing fee of $350.

Would you please acknowledge receipt of the above on the enclosed copy of this letter.

Sincerely,

Enclosures

cc: Commissioner John M. Quain, Chairman
Commissioner Robert K. Bloom
Lisa Crutchfield, Vice Chairman
Commissioner John Hanger
Commissioner David W. Rolka
Office of Consumer Advocate
Office of the Small Business Advocate
Office of Special Assistants
Office of Trial Staff

u:\tbond\rmt\letter

CERTIFICATE OF SERVICE

The undersigned certifies that true and correct copies of the Application of PECO Energy Company for Issuance of a Qualified Rate Order under Sections 2808 and 2812 of the Public Utility Code, filed by PECO Energy Company, have been serve on this date by first class mail, postage prepaid, or by hand delivery on the following:

John Quain, Chairman
Pennsylvania Public Utility Commission
Room 104, North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

Lisa Crutchfield, Vice Chairman
Pennsylvania Public Utility Commission
Room 116, North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

John Hanger, Commissioner
Pennsylvania Public Utility Commission
Room 107, North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

David Rolka, Commissioner
Pennsylvania Public Utility Commission
Room 110, North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

Robert Bloom, Commissioner
Pennsylvania Public Utility Commission
Room 112, North Office Building
P.O. Box 3265
Harrisburg, PA 17105-3265

Robert A. Christianson
Chief Administrative Law Judge
Office of the Administrative Law Judge
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

C.F. Hoffman, Esquire
Director Office of Trial Staff
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

Otto Hoffman
Deputy Executive Director
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

Ahmed Kaloko, Director
Bureau of Conservation Economics & Energy Planning
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

G.W. Barton, Director
Bureau of Audits
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

J. F. Povilaitis, Chief Counsel
Law Bureau
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

Bernard A. Ryan, Esquire
Small Business Advocate
Department of Commerce
Suite 1102 Commerce
300 N. 2nd Street
Harrisburg, PA 17101

David Kleppinger, Esquire
McNees, Wallace & Nurick
P.O. Box 1166
Harrisburg, PA 17108-1166

Irwin Popowsky, Esquire
Consumer Advocate
Office of Consumer Advocate
14th Floor, Strawberry Square
Harrisburg, PA 17120

Charles Ault
West Penn Power Company
800 Cabin Hill Drive
Greensburg, PA 15601

Mr. Frank Nadolny
Duquesne Light Company
P.O. Box 1930
Pittsburgh, PA 15230-1930

Lawrence P. Godlasky, Mgr. Reg. Affrs.
GPU Energy
100 APC Building
800 North Third Street
Harrisburg, PA 17102

Jo J. Mullendore, Govt. Affairs Rep.
Allegheny Power
800 North Third Street, Ste. 200
Harrisburg, PA 17102

Paul Russell, Esquire
Pennsylvania Power & Light Company
Two North Ninth Street
Allentown, PA 18101

Steve Feld, Esquire
Pennsylvania Power Company
P.O. Box 891
New Castle, PA 16103-0891

Mr. John P. Litz
UGI Utilities, Inc.
P.O. Box 1389
247 Wyoming Avenue
Kingston, PA 18704-0389

Judith L. Mondre, Executive Director
City of Philadelphia
Municipal Energy Office
1600 Arch Street, 7th Floor
Philadelphia, PA 19103

James Steffes, Director
Governmental Affairs
Enron Capital & Trade Resources
1400 Smith Street - EB#2408
Houston, TX 77002

Steven P. Hershey, Esquire
Community Legal Services, Inc.
1324 Locust Street
Philadelphia, PA 19107

David O. Epple, Director
Pennsylvania Electric Assoc.
301 APC Building
800 N. Third Street
Harrisburg, PA 17102

Frank Betley, Vice President
PA Rural Electric Association
P.O. Box 1266
Harrisburg, PA 17108-1266

Alan J. Barrak, Attorney for Mid-Atlantic Energy Project
Widener University Law School
3700 Vartan Way
Harrisburg, PA 17110

The undersigned certifies that PECO Energy has served notice of the Company's filing by first class mail, postage prepaid on the following:

Cynthia Datig
Dollar Energy Fund
P.O. Box 42329
Pittsburgh, PA 15203

Mike Welsh
IBEW - Local 459
408-412 Broad Street
Johnstown, PA 15906

Nan Davenport
Clear Air Council
3700 Vartan Way
Harrisburg, PA 17110

Lisa Yoho
Eastern Energy Marketing, Inc.
2900 Eisenhower Ave., Ste 300
Alexandria, VA 22314

The Hon. Thomas B. Hagen, Sec'y
Department of Community and Economic Development
433 Forum Building
Harrisburg, PA 17120

Stanley L. Laskowski
Acting Regional Administrator, EPA
841 Chestnut Building
Philadelphia, PA 19107

Jamie Winebrake
U.S. DOE
1880 JFK Blvd., Suite 501
Philadelphia, PA 19103

Daniel Tunnell, President
Pennsylvania Gas Association
800 N. 3rd Street, 2nd Floor
Harrisburg, PA 17102

Phillip D. McFarren
The McFarren Group
200 N. 3rd Street, Suite 1100
Harrisburg, PA 17101

Gary Triplett, Special Assistant to Dir.
Bureau of Air Quality Control
12th Flr., Market St. State Office Bldg.
P.O. Box 8468
Harrisburg, PA 17105-8468

Mike Welsh, Secretary/Treasurer
Utility Workers/Pennsylvania Utility Caucaus
408-412 Broad Street
Johnstown, PA 15906

Eugene M. Trisko
Attorney for UMWA
P.O. Box 596
Berkeley Springs, WV 25411

Richard H. Counihan, VP
Government Affairs
Edison Source
13191 Crossroads Parkway North
City of Industry, CA 91746

Bill Shane, Esquire
440 School Street
Indiana, PA 15701

Mr. George Ellis
Pennsylvania Coal Association
212 N. 3rd Street, Suite 102
Harrisburg, PA 17101

Charles Estes
Appalachian Pacific
1331 Pennsylvania Ave., N.W.
Suite 730
Washington, DC 20004

William T. Hawke, Esquire
Malatesta Hawke & McKeon
Harrisburg Energy Center
100 North Tenth Street, P.O.B. 1778
Harrisburg, PA 17105-1778

Mr. George Emmons
17 N. Lancaster Lane
Newtown, PA 18940

James A. Brodt
Smith Barney, Inc.
390 Greenwich Street
Fifth Floor
New York, NY 10013

Glenn Avick, Director
Engineering/Construction
University of Pittsburgh
3400 Forbes Avenue
Pittsburgh, PA 15260

Edward A. Essl, Coordinator
Capital City Task Force
AARP
225 Market Street, Suite 502
Harrisburg, PA 17101

James Royal
President & C.O.O.
Noble Group Corporation
3121 Norris Street
Philadelphia, PA 19121

Elliot M. Loyless, P.E.
Energy Cost Management
1901 Camp Florida Road
Brandon, FL 33510

Michael Walker
Bradford Stern
Buchanon Ingersoll
College Centre, 500 College Road East
Princeton, NJ 08540

Brian J. Hickey
Mid American Natural Resources
20005 West 8th Street
Suite 201
Erie, PA 16505

Glenn Winter, P.E.
1847 Radnor Road
York, PA 17402

Liz Fennell
Consolidated Edison Co.
511 Theodore Fremd Avenue
Room 112
Rye, NY 10580

Michael Karp
31 Appaloosa Road
Bellingham, WA 98226

Amy Leader, Esquire
Dechert Price & Rhoads
30 N. 3rd Street
Harrisburg, PA 17101

John V. Kulik, Vice President
Government Relations
Pennsylvania Food Merchants Assoc.
1029 Mumma Rd., P.O. Box 870
Camp Hill, PA 17011

Timothy McNulty
Dept. of Economic and Community Development
471 Forum Building
Harrisburg, PA 17120

Harry S. Geller, Esq.
Penna. Utility Law Project
118 Locust Street
Harrisburg, PA 17101-1414

Peter J. Thompson
Andrews & Kurth, LLP
1701 Pennsylvania Ave., N.W.
Washington, DC 20006

Scott J. Rubin, Esquire
Public Utility Consulting
3 Lost Creek Drive
Selinsgrove, PA 17870

Susan M. Shanaman
212 N. Third Street
Suite 203
Harrisburg, PA 17101-1505

John E. Molinda
Strategic Energy, Ltd.
Two Gateway Center
Pittsburgh, PA 15222

Brian A. Rider, President
Pennsylvania Retailers' Association
224 Pine Street
Harrisburg, PA 17101

Deborah Schachter
163 Silk Farm Road
Concord, NH 03301

George J. Miller, Esquire
Dechert, Price & Rhoads
3400 Centre Square West
1500 Market Street
Philadelphia, PA 19102

Rodney Raphael Akers, Esquire
City of Pittsburgh
313 City-County Building
414 Grant Street
Pittsburgh, PA 15219-2453

Bill McCue
Merck & Co., Inc.
Sumneytown Pike
P.O. Box 4, WP2-1
West Point, PA 19486-0004

Byron Williamson
Englehard Power Marketing, Inc.
101 Wood Avenue
Iselin, NJ 08830-0770

Dan Delaney, Esquire
Kirkpatrick & Lockhart
240 N. Third Street
Harrisburg, PA 17101

Michael D. Klein, Esquire
LeBoeuf, Lamb, Greene & MacRae
200 North Third Street - Suite 300
P.O. Box 12105
Harrisburg, PA 17108-2105

Patricia Armstrong, Esquire
Thomas, Thomas, Armstrong & Niesen
212 Locust Street - Suite 500
P.O. Box 9500
Harrisburg, PA 17108-9500

John E. Molinda
Strategic Energy, Ltd.
2 Gateway Center
Pittsburgh, PA 15222

Eirk Hansen
Delmarva Power
800 King Street
Wilmington, DE 19899

Liz Robinson
ECA
1924 Arch Street
Philadelphia, PA 19103

G. Philip Nowak, Esquire
Wiley, Rein & Fielding
1776 K Street., N.W.
Washington, DC 20006

Andre C. Dasent, P.C.
900 Bourse Building
21 South Fifth Avenue
Philadelphia, PA 19106

Seymour Kurland, Esquire
Pamela Foa, Esquire
Law Dept. - ARA Towers
15th Floor - 1101 Market Street
Philadelphia, PA 19107

Joan C. Brandeis, Esquire
Robert L. Kendall, Jr. Esquire
Schnader, Harrison, Segal & Lewis
Suite 3600 - 1600 Market Street
Philadelphia, PA 19103

Renn C. Fowler, Esquire
Real Property Division, LRDO
Office of General Counsel
General Services Administration
Room 4124 - 18th & F Sts., NW
Washington, DC 10405

Real Property Division, LRDO
Office of General Counsel
General Services Administration
Room 4124 - 18th & F Sts., NW
Washington, DC 10405

Vincent J. Walsh, Jr. Esquire
SEPTA, Legal Department
714 Market Street
Philadelphia, PA 19106

Billie Ramsey, Esquire
Executive Director
ARIPPA
1300 Market Street
Lemoyne, PA 17043

Anthony M. Dowdle, Esquire
Naval Facilities Engineering Command
200 Stovall Street
Alexandria, VA 22332-2300

Sam DeFrawi
Director, Rate Intervention
NAVFACENGCOM, Code 02R
200 Stovall Street
Alexandria, VA 22332-2300

The Parties listed above include the participants in PECO Energy's last general base rate case (Limerick 2 at Docket No. R-891364) and the non-legislative parties on the Commission's Monday Group Stakeholder list.

Paul R. Bonney
Assistant General Counsel
PECO Energy Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101-8699
(215) 841-4252

Date: January 22, 1997

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY FOR ISSUANCE OF A QUALIFIED RATE ORDER UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE	:	**APPLICATION DOCKET NO. _____**

APPLICATION OF
PECO ENERGY COMPANY

PECO Energy Company ("PECO" or the "Company"), pursuant to Sections 2808 and 2812 of the Pennsylvania Public Utility Code (the "Code") (66 Pa. C.S. §§ 2808 and 2812), hereby requests that the Pennsylvania Public Utility Commission (the "Commission") issue a Qualified Rate Order (1) finding that the recovery by PECO of approximately $3.9 billion in Qualified Transition Expenses, consisting of transition or stranded costs, expenses associated with the issuance and service of Transition Bonds and related recapitalization costs, is just and reasonable, (2) concluding that the sale, assignment, transfer or pledge of the Intangible Transition Property created by the Qualified Rate Order and the issuance of Transition Bonds secured by such Intangible Transition Property is in the public interest and (3) approving the imposition of the Intangible Transition Charge ("ITC") and corresponding base rate decrease formulae, as well as the specific tariff revisions, contained in Supplement No. 11 to Tariff Electric - Pa. P.U.C. No. 2 ("Supplement 11") to become effective upon the successful issuance of the Transition Bonds.

The Company asks the Commission to declare that certain provisions of its Qualified Rate Order shall be irrevocable and that it will not take any action, either directly or indirectly, that

would impair such provisions, or the rates and other charges authorized thereby, until the Transition Bonds are fully paid and discharged. To ensure that PECO's customers receive the benefits of this proposal at the earliest possible date, the Company further asks that the Commission invoke the expedited review procedures set forth in Section 2812(B)(1)(I) of the Code. Finally, PECO requests that the Commission grant such other approvals under Chapter 11 of the Code as it concludes are necessary and appropriate. A proposed form of Order has been attached hereto as Exhibit 1.

IDENTITY AND DESCRIPTION OF THE APPLICANT

1. The name and address of the Applicant are as follows:

   PECO Energy Company
   2301 Market Street
   P. O. Box 8699
   Philadelphia, PA 19101-8699

2. The names and address of the Applicant's attorneys are as follows:

   James W. Durham, Esquire
   Senior Vice President and General Counsel
   Paul R. Bonney, Esquire
   Ward L. Smith, Esquire
   Assistant General Counsel

   PECO Energy Company
   2301 Market Street
   P.O. Box 8699
   Philadelphia, PA 19101-8699

3. PECO is a Pennsylvania public utility corporation duly organized and existing under the laws of the Commonwealth of Pennsylvania and is engaged in the business of supplying and distributing electricity and natural gas. Electric service is furnished in all or substantially all of Bucks, Chester, Delaware, Montgomery and Philadelphia Counties and a portion of York County. Gas service is provided in substantial portions of Bucks, Chester, Delaware and Montgomery Counties and a small section of Lancaster County.

4. As of December 31, 1996, PECO furnished electric service to 1,471,229 retail customers, broken down as follows:

Residential	1,324,448
Commercial	142,431
Industrial	3,299
Other	1,051

BACKGROUND FINANCIAL INFORMATION

5. Attached as Exhibit 2 is PECO's balance sheet as of September 30, 1996, preliminary journal entries and a pro forma balance sheet giving effect to the transactions proposed herein. When year-end 1996 financial data has been publicly disclosed, Exhibit 2 will be updated.

6. Attached as Exhibit 3 is PECO's income statement for the twelve months ended September 30, 1996, preliminary journal entries and a pro forma income statement giving effect to the transactions proposed herein. When year-end 1996 financial data has been publicly disclosed, Exhibit 3 will be updated.

7. All annual reports, tariffs, certificates of public convenience, applications, securities certificates and similar documents filed by PECO and its predecessor, constituent and affiliated companies are made a part hereof by reference.

SUMMARY OF THE PROPOSED TRANSACTIONS

8. Through this filing, PECO is seeking to utilize the provisions of recently-enacted Sections 2808 and 2812 of the Code to securitize a portion of the generation-related costs that it projects will not be recoverable upon the advent of retail competition in Pennsylvania commencing January 1, 1999, together with associated financing costs. For the reasons which follow, PECO believes that the relief requested herein is just and reasonable and in the public interest and should, therefore, be approved.

9. A general description of the specific transactions contemplated is provided later in this Application and in the supporting testimony being filed herewith. In summary, the Commission's issuance of the proposed Qualified Rate Order and corresponding approval to implement the proposed ITCs will create an irrevocable right to recover certain Qualified Transition Expenses, including approximately (a) $3.6 billion of stranded costs, (b) $23.8 million of issuance expenses and (c) $253.5 million of costs associated with the use of the proceeds, including the costs to service the Transition Bonds and any necessary credit enhancement. That property right, denominated "Intangible Transition Property" in Section 2812, will then be sold, assigned, transferred or pledged, either directly or indirectly, to a third party, or a series of third parties, which will finance the acquisition through the issuance of Transition Bonds. The

proceeds from the sale of the Intangible Property funded by the Transition Bonds will be remitted to PECO, which, in turn, will use the proceeds to reduce its stranded costs and capitalization and to pay related transaction costs.

10. Upon the successful issuance of the Transition Bonds and the receipt of proceeds, PECO will simultaneously implement ITCs to commence recovery of the principal, interest and a servicing fee with respect to the Bonds. Contemporaneously, PECO will reduce its base rates to remove the revenue requirement associated with the assets which have been securitized. PECO will act as the "servicer" of the Transition Bonds, collecting and passing through to the third-party issuers the dollars recovered under the ITCs. To ensure that it collects sufficient revenues to service the Transition Bonds, PECO is also proposing, as part of this filing, that the Commission approve the specific reconciliation procedures set forth in Supplement 11.

11. A flow-chart depicting the foregoing process has been provided as Exhibit 4. While Exhibit 4 assumes, for illustrative purposes, a single set of transactions, it is more likely that the Transition Bonds will be issued in more than one series over a period of up to 24 months following the issuance of the Qualified Rate Order. In addition, in accordance with the provisions of Section 2812(B)(5) of the Code, periodic adjustments to the ITCs will be required to ensure the recovery of sufficient revenues to pay the principal and interest on the Transition Bonds.

DATA TO BE FILED IN COMPLIANCE WITH SECTION 2812(A)(2)(I)

12. **Complete Accounting Of Transition Or Stranded Costs.** Based on analyses completed to date, PECO has determined that its net stranded costs, following mitigation, will be

approximately $7.1 billion. This amount was derived by (a) quantifying PECO's net electric generation-related costs as estimated at December 31, 1998, and (b) deducting the market value of the Company's investment in electric generating plants and facilities, as expressed in present value terms as of that same date.

As explained by Alan B. Cohn, Manager of the Business Analysis and Support Section of PECO's Rates and Regulatory Affairs Division, the Company's net electric generation-related costs at December 31, 1998 are estimated to approximate $9.70 billion and may be summarized as follows:

Category	$ In Millions
Net Investments In Existing Generating Plants And Facilities	$6,514.0
Regulatory Assets and Other Deferred Charges	$2,632.6
Underfunded Nuclear Decommissioning Costs	$ 281.8
Costs Of Retiring Fossil Generating Plants	$ 275.1
	$9,703.5

Extensive supporting detail for each of the foregoing cost categories is set forth in Mr. Cohn's direct testimony and related exhibits, which may be found in the separately bound Exhibit 5.[1/]

The quantification of the market value of PECO's existing generating facilities at December 31, 1998 is described by Thomas P. Hill, Jr., Vice President and Controller of the Company. As Mr. Hill points out, PECO developed a model that calculated the net margin which each generating unit could reasonably be expected to contribute over its remaining life. In

---

1/ Further analysis may identify other stranded costs. If that occurs, PECO will include those costs in its restructuring plan filing to be made later this year.

summary, the model starts with the market price, calculated on an hourly basis, which PECO's facilities would likely command in a competitive market. Those values are then multiplied by the generation produced in each hour by each unit to develop an estimate of projected revenues per unit. The costs of producing the power are then subtracted to establish an after-tax income stream for each unit for each year over its remaining service life. The resulting income streams, in turn, were restated on a present value basis as of December 31, 1998, by discounting the streams at PECO's after-tax cost of capital (8.88%). Mr. Hill's direct testimony and supporting exhibits are also contained in Exhibit 5.

The market price projections used in the model reflect conservative estimates derived from several different market clearing price studies performed at PECO's request. John F. Bustard, a Senior Engineer in PECO's Bulk Power Enterprises group, summarizes those studies, while Bangalore S. Venkateshwara and William H. Hieronymus discuss the results of the specific analyses which they performed.[2/] The direct testimony and exhibits being sponsored by Messrs. Bustard, Venkateshwara and Hieronymus are similarly contained in Exhibit 5.

Utilizing the results of its three market price analyses, PECO derived estimates of the market value of its facilities at December 31, 1998 ranging from $2.04 billion to $3.02 billion. The average of those three values equals $2.57 billion, which, when subtracted from PECO's net generation-related costs of $9.70 billion, yields net stranded costs of approximately $7.1 billion. Through this filing, PECO is seeking to securitize $3.6 billion, or approximately one-half, of its

---

2/ Dr. Venkateshwara is a Vice President of ICF Resources, Incorporated, located in Fairfax, Virginia; Dr. Hieronymus is a Managing Director of Putnam, Hayes & Bartlett, a Cambridge, Massachusetts-based economic and management consulting firm.

estimated stranded costs, and related financing costs. More specifically, and as Mr. Hill explains in his testimony, PECO is requesting Commission approval to securitize (a) $239 million of deferred fuel costs; (b) $3.36 billion, representing a pro rata slice of (i) its projected stranded investment in generating facilities and (ii) other regulatory assets which either are currently being amortized through existing rates or have been recognized by the Commission for future recovery; (c) $23.8 million of expenses associated with the issuance of Transition Bonds; and (d) $253.5 million of costs associated with the use of proceeds, including the costs to service the Transition Bonds and any necessary credit enhancement.

13. **Detailed Information Regarding The Proposed Sale Of Intangible Transition Property And/Or Issuance Of Transition Bonds.** The proposed sale, assignment, transfer or pledge of Intangible Transition Property and the issuance of Transition Bonds are described in the direct testimonies of J. Barry Mitchell and Howard L. Hiller, which may be found in Exhibit 5. Mr. Mitchell, PECO's Vice President of Finance and Treasurer, explains that the Intangible Transition Property created by the requested Qualified Rate Order will be transferred either directly or indirectly to a newly-formed, "bankruptcy-remote" special purpose entity, such as a corporation or trust, which will issue the Transition Bonds.

PECO expects, subject to market conditions, that the Transition Bonds will be issued in one or more series, and that each series may be issued in one or more classes. Each series will have an expected final maturity of up to ten years. The proceeds from the sale of the Intangible Transition Property funded by the Transition Bonds will be remitted to PECO, which will utilize them to reduce its stranded costs and capitalization and to pay related financing costs.

Collections of the ITCs approved in the Qualified Rate Order will be passed through to the Transition Bondholders as periodic payments of interest and principal.

Mr. Hiller, a Vice President in the Fixed-Income Capital Markets Group of Salomon Brothers Inc, describes the current and prospective market for asset-backed securities such as the Transition Bonds. In his opinion, the Transition Bonds will be a new and attractive asset class for fixed-income investors due to their "pass-through" nature, longer average lives relative to other asset-backed securities and minimal amortization uncertainty. He further points out that the Transition Bonds can be structured to achieve a AAA bond rating and, accordingly, will most certainly be issued at a rate lower than PECO's weighted average cost of capital.

PECO plans to proceed along the lines outlined above and the maximum benefits to PECO and its customers will be realized if the transaction is characterized as a sale for accounting purposes and as a financing for tax purposes. For the reasons discussed by Mr. Mitchell and John J. Gillen, a partner with Coopers & Lybrand, L.L.P.,[3/] PECO believes that, from an accounting standpoint, the proposed securitization will qualify as a sale under Statement of Financial Accounting Standards No. 125. In terms of tax treatment, PECO is in the process of applying to the Internal Revenue Service for a letter ruling confirming that the sale of Intangible Transition Property will not be treated as a taxable event for PECO. Depending upon the final resolution of these issues, it may be necessary for PECO to pursue an alternative financing vehicle as outlined by Mr. Mitchell, whereby the Intangible Transition Property is transferred to a specially created PECO finance subsidiary which then issues the Transition Bonds.

3/ Mr. Gillen's testimony and exhibits also appear in Exhibit 5.

14. **Planned Use Of Proceeds** Mr. Mitchell describes in his testimony how PECO currently anticipates using the gross proceeds from the sale of the Intangible Transition Property funded by the $3.9 billion of Transition Bonds. As he explains, PECO will utilize approximately $277 million to pay issuance and refinancing costs and apply $239 million to reduce its deferred fuel costs. The Company will use the remaining $3.36 billion to reduce its existing capitalization through the retirement of outstanding debt, the retirement and repurchase of preferred stock and the reduction of common shareholder equity through stock buybacks, open market purchases and/or dividends to shareholders.

The specific steps taken by PECO to reduce its capitalization will depend, in large part, on the date on which the proceeds from the sale of Transition Bonds become available, the then prevailing market conditions and the advice of the Company's financial advisors. For that reason, PECO requests that the Commission make clear, in its Qualified Rate Order, that PECO will have the flexibility to structure its use of proceeds in the most cost-effective manner given the circumstances at that time.

INTANGIBLE TRANSITION CHARGES AND BASE RATE DECREASES

15. Section 2808(E)(2) of the Code requires that, upon the successful issuance of Transition Bonds, a utility (a) shall impose upon and collect from customers the ITCs approved by the Qualified Rate Order and (b) simultaneously remove from existing rate levels an amount equal to the revenue requirement of the transition or stranded costs for which the Transition Bonds have been successfully issued. A breakdown, by customer class, of the ITCs and base rate

reductions proposed by PECO in this filing is set forth in Supplement 11, which has been attached as Exhibit 6. The derivation of those figures is explained by Mr. Cohn and Stephen R. Xander, Manager, Tariff Administration and Policy in PECO's Rates & Regulatory Affairs Division.[4/] In short, the Commission's approval of this Application would result in annual bill reductions for Pennsylvania customers estimated at $95 million, or almost a billion dollars over the life of the Transition Bonds.

16. In calculating the base rate decreases, PECO first determined the extent to which the costs of each stranded asset were already included in existing rates. That analysis is described by Mr. Cohn in his testimony and is summarized in his Exhibit ABC-10. Once the aggregate base rate reduction was determined, that amount had to be allocated amongst PECO's retail rate classes. Consistent with the provisions of Section 2808(A) of the Code, PECO utilized the same methodology to allocate generation-related costs that it employed in its most recent general base rate proceeding at Docket No. R-891364, Pennsylvania Public Utility Commission v. Philadelphia Electric Co., 74 Pa. P.U.C. 1 (1990). The application of those allocation factors and the corresponding customer class rate reductions are discussed and quantified by Mr. Cohn in his direct testimony and supporting exhibits.[5/]

17. The base rate reduction allocated to a particular customer class was then expressed as a percentage of that class's projected revenues. The percentage so derived for each customer

---

4/ Mr. Xander's direct testimony and accompanying exhibits may be found in Exhibit 5.

5/ As noted by Mr. Cohn, certain customer classes (e.g., SLS, SLE, POL) are not currently paying any fixed generation-related costs and, accordingly, would not be entitled to share in any base rate decreases.

class will be applied to the total bill of each customer in that class. Through the foregoing process, PECO will ensure that existing inter-class and intra-class cost relationships are left undisturbed.

18. The ITCs were derived in much the same manner. First, Mr. Cohn determined the amount that would need to be collected, on an annual basis over the life of the Transition Bonds, to provide for payments of interest and principal to the issuers. Like the base rate reductions, the ITCs were calculated on an individual customer class basis, consistent with the historic allocation of generation-related costs, and will be applied as a percentage to each customer's total bill. As explained by Messrs. Cohn and Xander, this symmetry in the application of base rate decreases and ITCs will guarantee that all customers and customer classes receive the appropriate level of benefits generated by this securitization.

STATUTORY STANDARDS

19. Section 2812(A)(2)(III) of the Code requires that the Commission determine that (a) the recovery of transition and/or stranded costs is just and reasonable and (b) the entry of a Qualified Rate Order approving the sale, assignment, transfer or pledge of Intangible Transition Property and the issuance of Transition Bonds is in the public interest. PECO respectfully submits that the data provided with this filing fully supports those findings.

20. Recovery of the stranded costs identified in this filing is not only just and reasonable, but is also required if PECO is to be treated fairly for the investments it has made, and costs it has incurred, in furtherance of its statutory obligation to serve. As explained by Mr. Hill,

the specific costs which PECO is seeking to securitize either are being recovered currently through rates or would be recoverable in a regulated environment. Indeed, PECO has structured this filing to minimize and hopefully eliminate controversy by including in its claimed stranded costs only (1) certain deferred fuel costs and (2) a pro rata slice of (a) its prudent investments in electric generating facilities that have been and will continue to be used and useful in satisfying customer needs and (b) other regulatory assets which either are currently being amortized through existing rates or have been recognized by the Commission for future recovery.

21. In evaluating PECO's requested relief in this proceeding, the Commission should also take into consideration the substantial steps taken by the Company to mitigate its stranded costs and to moderate rate levels. For example, PECO has significantly accelerated the depreciation and amortization of various generation facilities and regulatory assets, and has reduced its overall employee complement by approximately 37% in the past seven years. These and other initiatives, which are summarized by Mr. Hill in his testimony, have enabled PECO to substantially reduce its stranded costs.

22. It is equally clear that the securitization of PECO's stranded costs at this time is in the public interest. First, and perhaps most importantly, approval of PECO's request will enable it to immediately reduce customers' bills by an estimated $95 million per year or almost a billion dollars over the next ten years. Second, and as pointed out by Messrs. Mitchell and Hiller, there are cost savings to be achieved in allowing PECO to take advantage of the favorable interest rates prevailing today and avoid the potential excess of such financings in the future. Third, a favorable ruling in this case would eliminate some of the uncertainty surrounding the Commonwealth's

electric utility restructuring efforts. Finally, issuance of the proposed Qualified Rate Order would send a positive signal that businesses which invest in Pennsylvania can expect to be treated equitably. This, together with the immediate rate reduction, would surely serve to promote Governor Ridge's goal of spurring economic growth and job creation.

QUALIFIED RATE ORDER

23. As noted previously, PECO has attached, as Exhibit 1 to this Application, a proposed form of Order. Exhibit 1 has been exhaustively reviewed by PECO's financial advisors who have indicated that it is critically important to the marketability of the Transition Bonds that the Commission adopt the same or similar language, safeguards and reconciliation procedures in the Qualified Rate Order issued in this proceeding and declare the same to be irrevocable.

OTHER REGULATORY APPROVALS

24. This Application is being filed pursuant to Sections 2808 and 2812 of the Code. It is conceivable, however, that the Commission could conclude that other provisions of the Code are implicated. For example, the Commission might determine that the transactions proposed herein constitute a sale of used and useful utility property under Section 1102(a)(3). If that proves to be the case, PECO requests that the Commission find that the sale of the Intangible Transition Property created by its Qualified Rate Order is necessary and proper for the service and convenience of the public for all of the reasons previously stated.

DATA TO BE FILED IN RESPONSE TO THE COMMISSION'S PROPOSED PRE-FILING GUIDELINES

25. On January 16, 1997, the Commission issued Proposed Pre-Filing Guidelines (the "Guidelines") to assist it in its review of Section 2812 Qualified Rate Order Applications. Even though the Guidelines have not been finalized and remain subject to interpretation and potential revision, PECO has endeavored to supply as much of the requested data as reasonably possible. That information is set forth in Exhibit 7 and, to the extent necessary, can be supplemented if the Commission concludes that additional data would be helpful.

NOTICE

26. Sections 2808 and 2812 are silent with respect to the form and nature of the notice to be provided customers. However, to ensure that its customers are made aware of this filing as soon as possible, PECO, following discussions with Commission Staff and representatives of the Office of Consumer Advocate, began including bill inserts in the form attached as Exhibit 8 commencing with all bills issued on January 22, 1997, the date of this filing. In addition, PECO is publishing notice of this Application in all newspapers of general circulation in its service territory and proposes that notice also be published in the Pennsylvania Bulletin as soon as possible. Finally, PECO is serving copies of this filing on the Offices of Trial Staff, Consumer Advocate and Small Business Advocate and the Philadelphia Area Industrial Energy Users Group, and is providing immediate notice of its Application to all of the other parties which actively participated in the Limerick 2 rate case.

PROPOSED LITIGATION SCHEDULE

27. As noted previously, PECO requests that the Commission invoke the expedited (i.e. 120 day) procedures of Section 2812(B)(1)(I). PECO will, of course, work with all parties and the presiding Administrative Law Judge to develop a mutually-acceptable litigation schedule.

CONCLUSION

WHEREFORE, for the reasons set forth above, PECO Energy Company requests that the Pennsylvania Public Utility Commission approve this Application, issue an Order substantially in the form attached hereto as Exhibit 1 and grant such other approvals as may be required under Chapter 11 of the Public Utility Code.

Respectfully submitted,

James W. Durham, Esquire
Senior Vice President and General Counsel
Paul R. Bonney, Esquire
Ward L. Smith, Esquire

PECO Energy Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101-8699
(215) 841-4252

Dated: January 22, 1997

VERIFICATION

I, T. P. Hill, Jr., hereby declare that I am Vice President and Controller of PECO Energy Company; that as such I am authorized to make this verification on its behalf; that the facts set forth in the foregoing Application are true to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa. C.S. §4904 pertaining to false statements to authorities.

Date: January 22, 1997

T. P. Hill, Jr.

76788

Exhibit 1

Proposed Form of Order

QUALIFIED RATE ORDER

IT IS ORDERED:

1. The Commission finds that it is just and reasonable and in the public interest for PECO Energy to recover from its customers through Intangible Transition Charges amounts sufficient to recover the following Qualified Transition Expenses: (a) **$3,600.000** million in Transition or Stranded Costs, consisting of:

$2,134,474 million - Net Generating Plant and CWIP

$1,465,525 million - Regulatory Assets

(b) **$23.833** million in expenses relating to the sale of Intangible Transition Property and issuance of Transition Bonds, (c) an amount sufficient to provide for any credit enhancement of the Intangible Transition Property and to pay interest, redemption premiums, if any, and servicing expenses relating to the Transition Bonds, and (d) **$253.503** million in costs associated with the Company's use of the proceeds from the sale, assignment, transfer or pledge of Intangible Transition Property or the issuance of Transition Bonds principally to reduce the Company's Transition or Stranded Costs and to reduce related capitalization.

2. The Company is directed to implement a reduction in its customer rates, on the following terms: (a) a rate reduction shall be implemented only upon successful issuance of Transition Bonds authorized by this Qualified Rate Order (if the issuance is in one or more series, a rate reduction shall be calculated and implemented corresponding to each such series); (b) the aggregate rate reduction shall be in an amount equal to the revenue requirement currently included in the Company's rates for the Transition or Stranded Costs for which Transition Bonds have been issued on that date; (c) for such Transition or Stranded Costs that are currently in the Company's base rates, the Company shall remove from its base rates sufficient revenue requirement such that it will no longer receive either a return of or a return on those investments;

(d) for such Transition or Stranded costs that are not currently in the Company's base rates, the Company shall be prohibited from recovering in its base rates the revenue requirement associated with amortization of those expenses; (e) for the deferred fuel balances, the Company shall settle those deferred fuel balances; (f) the rate reduction shall be applied to customer bills using the method and allocation set forth in the Company's filing, testimony, exhibits and tariff; and (g) the Intangible Transition Charges associated with the Transition Bonds issued on that date shall be applied to customer bills simultaneously with the rate reduction. The Commission approves the supplements and changes to the Company's Electric Service Tariff, as proposed by the Company in its filing, testimony, and exhibits, to implement this reduction in its customer rates.

3. The Commission hereby authorizes the Company to impose on and collect from customers through non-bypassable charges applied to the bill of every customer accessing the Company's transmission or distribution network, the "Intangible Transition Charges" in an amount equal to $3,877.336 million plus an amount sufficient to provide for any credit enhancement and to pay interest, redemption premiums, if any, and servicing expenses relating to the Transition Bonds. The Intangible Transition Charges shall be collected over periods of time and in such amounts as are necessary to amortize each series of Transition Bonds in accordance with the terms thereof. Notwithstanding anything else in this Qualified Rate Order, the Intangible Transition Charges shall be collected from customers until all of the Transition Bonds are discharged.

4. The Commission finds that the Company's imposition on customers of Intangible Transition Charges in an amount sufficient to recover an aggregate amount of (a) **$3,877.336** million of Qualified Transition Expenses, comprised of **$3,600.000** million of the Company's Transition or Stranded Costs under 66 Pa.C.S. § 2804 (relating to standards) and 66

Pa.C.S. § 2808 (relating to Competitive Transition Charge), **$23.833** million in costs relating to the sale of Intangible Transition Property or issuance of Transition Bonds, and **$253.503** million in costs associated with the Company's use of the proceeds (including the cost of retiring the Company's debt or equity), plus (b) an amount of Qualified Transition Expenses sufficient to provide for any credit enhancement and to pay interest, redemption premiums, if any, and servicing expenses relating to the Transition Bonds is in the public interest and is just and reasonable.

5. The Intangible Transition Charges shall be applied to customer bills using the methodology and allocation set forth in the Company's filing, testimony, exhibits, and Tariff. The Commission approves the supplements and changes to the Company's Electric Service Tariff as proposed by the Company in its filing, testimony, and exhibits to implement the Intangible Transition Charges. Pursuant to 66 Pa.C.S. § 2812(B)(5), the Commission hereby authorizes the Company to make periodic adjustments to the Intangible Transition Charges to ensure the recovery of revenues sufficient to fully recover the Qualified Transition Expenses. The revenues collected through the Intangible Transition Charges shall be determined to be sufficient for this purpose if and only if the revenues collected through the Intangible Transition Charges are sufficient to amortize the Transition Bonds (after payment of accrued interest and servicing fees) in accordance with the terms thereof. The periodic adjustments shall be of two types, an annual adjustment on the anniversary of the issuance of this Qualified Rate Order (the "Annual Adjustment"), and additional adjustments to occur in the intervals between the Annual Adjustments (each, an "Interim Adjustment") as required by the Company. For each Annual Adjustment, the Company shall file with the Commission: (a) an accounting of its collections of Intangible Transition Charges for the previous annual period; (b) a statement of any over- or under-collections; (c) the charge or credit to be added to Intangible Transition Charges during the

next year to ensure that the Intangible Transition Charges revenue collections will be sufficient to amortize the Qualified Transition Expenses in accordance with the amortization schedule for the principal amount of Qualified Transition Expenses ("Projected QTE Balances"); and (d) any proposal by the Company to modify the reconciliation methodology. Pursuant to 66 Pa.C.S. § 2812(B)(5), the Commission shall approve all Annual Adjustments within 90 days of the Company's Annual Adjustment filing. The Interim Adjustments shall occur on such additional dates ("True-Up Dates") as are designated for the Transition Bonds by the terms thereof. For each Interim Adjustment, the Company shall file with the Commission (a) the expected Intangible Transition Charge revenues to be collected between the date of filing and the next True-Up Date; (b) the Projected QTE Balances for the next True-Up Date; and (c) a charge or credit to be added to Intangible Transition Charges for that period to ensure that Intangible Transition Charge revenue collections will be sufficient to amortize the Qualified Transition Expenses in accordance with the Projected QTE Balance for the next True-Up Date. The recalculation of the ITC values contained in each such filing shall become effective in 10 days, subject to Commission review in the next Annual Adjustment proceeding.

6. This Qualified Rate Order authorizes the Company to include as part of its Qualified Transition Expenses **$23.833** million of costs of issuing the Transition Bonds and **$253.503** million of costs associated with the Company's use of the proceeds of those Transition Bonds or the sale of Intangible Transition Property. The Company shall effect a reconciliation between its estimate of these costs and the actual costs incurred on the following terms: (a) the Company shall establish a tracking account for all expenses incurred related to these estimated costs; (b) when the Company has completed a full accounting of actual costs, it shall file with the Commission supporting documents for those actual costs and shall state the amount by which the actual costs differ from the estimated costs; (c) at that same time, the Company shall file with the

Commission a reconciliation of any over- or under-collection of such costs, including the payment or recovery of interest on over - or under-collection balances and (d) this reconciliation shall be implemented through automatic adjustments to the Company's base rates, and not through any Intangible Transition Charges.

7. The Commission finds that the methodology under which the Company will recover the Intangible Transition Charges authorized by this Qualified Rate Order satisfies the provisions of 66 Pa.C.S. § 2812(G), which require that the methodology not shift inter-class or intra-class costs and that the methodology maintain consistency with the allocation methodology for utility production plant used by the Commission in the Company's last base rate proceeding.

8. The Commission concludes that it is in the public interest to, and hereby authorizes the Company and any Assignee to (a) assign, sell, transfer or pledge Intangible Transition Property in an amount sufficient to recover all its Qualified Transition Expenses (such term includes all right, title and interest of the Company or any Assignee in this Qualified Rate Order and in all revenues, collections, claims, payments, money or proceeds of arising from Intangible Transition Charges pursuant to this Qualified Rate Order to the extent that this Qualified Rate Order and the rates and other charges authorized hereunder are declared irrevocable) and (b) issue, sell and refinance, in reliance on this Qualified Rate Order, one or more series of Transition Bonds, each series with a final maturity of up to ten years, and each series in one or more classes secured by the Intangible Transition Property created by this Qualified Rate Order. The last issuance of Transition Bonds and any accompanying assignment, sale, transfer, or pledge of Intangible Transition Property under this Qualified Rate Order shall be effected within two years from the date of this Qualified Rate Order. Notwithstanding the foregoing, the Company retains sole discretion regarding whether to assign, sell or otherwise transfer Intangible

Transition Property created hereby or to issue or cause the Transition Bonds to be issued or refinanced, including the right to defer or postpone, beyond the time period specified in the foregoing sentence, such assignment, sale, transfer, issuance or refinancing.

9. If the Company or any Assignee refinances the Transition Bonds, the Intangible Transition Charges authorized in this Qualified Rate Order shall be adjusted in accordance with the true-up mechanism described in paragraph 5 of this Qualified Rate Order to ensure the recovery of revenues sufficient to make all interest, redemption premiums, if any, servicing expenses and principal payments with respect to Transition Bonds issued in that refinancing. The revenues collected through the Intangible Transition Charges shall be determined to be sufficient for this purpose if and only if the revenues collected through the Intangible Transition Charges provide for the amortization of Transition Bonds in accordance with any amortization schedule set forth in any prospectus or other offering document provided to the holders of the refinanced bonds.

10. The Commission orders that the Company use the proceeds from the assignment, sale, transfer or pledge of Intangible Transition Property and the issuance and sale of Transition Bonds principally to reduce the Company's Transition or Stranded Costs and to reduce related capitalization. The Company currently anticipates using, and the Commission hereby authorizes the Company to use, the proceeds from the assignment, sale, transfer or pledge of the Intangible Transition Property created by this Qualified Rate Order as follows: approximately **$277.000** million to be used to pay costs of issuing the Transition Bonds and costs associated with the Company's use of the proceeds; approximately **$240.000** million to be applied to reduce the Company's deferred fuel costs; and approximately **$3,360.000** (less any amounts representing required credit enhancement with respect to the Transition Bonds) million to be used to reduce

the Company's existing capitalization through the retirement of outstanding debt and preferred stock and the return of investment to equity holders through stock buybacks, dividends and market purchases.

11. The Commission hereby declares that the Company and its Assignee should be afforded maximum flexibility in the issuance or refinancing of Transition Bonds and the use of the proceeds thereof.

12. It is ordered that the Company shall file with the Commission, no later than 120 days after the issuance or refinancing of Transition Bonds, a description of the final structure of each issuance or refinancing of such Transition Bonds, including the principal amount, the price at which such series and/or class of Transition Bonds were sold, payment schedules, the interest rate and other financing costs, and the final plans for the Company's use of the proceeds of such offering, and in the case of any subsequent refinancing of Transition Bonds specifying the effect upon the rates authorized herein. Notwithstanding such filing, the final structure of each such issuance or refinancing and the related effect on rates authorized herein shall not be subject to change or revision by the Commission after the date of such issuance or refinancing.

13. To the extent that the Company, or any Assignee, assigns, sells, transfers, or pledges any interest in the Intangible Transition Property created hereby, the Commission authorizes the Company to contract, for a specified fee, with such Assignee for the Company to continue to operate the system to provide electric services to the Company's customers, to impose and collect the applicable Intangible Transition Charges for the benefit and account of the Assignee to make the periodic adjustments of Intangible Transition Charges contemplated under paragraph 5 of this Qualified Rate Order, and to account for and remit the applicable Intangible

Transition Charges to or for the account of the Assignee free of any charge, deduction or surcharge of any kind (other than the specified contractual fee referred to above). The Commission also authorizes the Company to contract with the Assignee and an alternative party, which may be a trustee, that the alternative party will replace the Company under its contract with the Assignee and perform the obligations of the Company contemplated in this Qualified Rate Order. The obligations of the Company (a) shall be binding upon the Company, its successors and assigns and (b) shall be required by the Commission to be undertaken and performed by the Company and any other entity which provides electric service to a person that was a customer of the Company located within the Company's certificated territory on January 1, 1997, or that became a customer of electric services within such territory after January 1, 1997, and is still located within such territory, as a condition to providing service to such customer or the municipal entity providing such services in place of the Company by the Company or other entity.

14. The Commission hereby declares that paragraphs 1 through 14 of this Qualified Rate Order shall be irrevocable for purposes of Section 2812 of the Code and accordingly agrees that it will not directly or indirectly, by any subsequent action, reduce, postpone, impair or terminate this Qualified Rate Order or the rates and other charges authorized hereby, including, without limitation, the Intangible Transition Charges, until the Transition Bonds are fully paid and discharged. The Commission further declares hereby that the right, title and interest of the Company and any Assignee in this Qualified Rate Order and the Intangible Transition Charges, the rates and other charges authorized hereby and all revenues, collections, claims, payments, money or proceeds of or arising from the same constitutes Intangible Transition Property. To the extent that an assignment, sale or transfer of the Intangible Transition Property resulting from this Qualified Rate Order, or the issuance of related Transition Bonds, is not effected within the period specified in paragraph 8 of this Qualified Rate Order, the provisions of

this paragraph 14 shall lapse and terminate; provided, however, that the Commission, through subsequent application by the Company, may reinstate the irrevocability of the whole of or any portion of this Qualified Rate Order.

15. In this Order the Commission authorizes the recovery of **$3,600.000** million of the Company's Transition or Stranded Costs. In accordance with 66 Pa.C.S. § 2812(B)(1)(I), the Commission makes no determination in this Order regarding the Company's recovery of Transition or Stranded Costs over and above that **$3,600.000** million amount. The Commission hereby directs that the Company may, by subsequent Application or Applications, request the Commission to consider additional Qualified Transition Expenses and other issuances of Transition Bonds; the Commission defers consideration of any such request until such time as the Company submits such additional Applications for Qualified Rate Orders.

Exhibit 2

September 30, 1996 Balance Sheet,
Pro Forma Balance Sheet and Proposed Journal Entries

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEET
(MILLIONS OF DOLLARS)

	September 30, 1996 (Unaudited)	Proforma adjustments	September 30, 1996 (Adjusted)
ASSETS			
Utility Plant			
Net Plant at Original Cost	$ 10,883	$ (2,435) A	$ 8,448
Current Assets			
Cash and Temporary Cash Investments	61	3,600 B (3,361) D	300
Restricted cash	-	253 B 24 B (24) C (253) D	0
Other Current Assets	405		405
	466	239	705
Regulatory and Other Assets			
Deferred fuel costs	96	(96) B	0
Total Regulatory and Other Assets	3,457	2,435 A (3,361) B	2,531
TOTAL	$ 14,902	$ (3,218)	$ 11,684
CAPITALIZATION AND LIABILITIES			
Capitalization			
Common Shareholders' Equity			
Common Stock (No Par)	$ 3,518	926 D	2,592
Other Paid-In Capital	1		1
Retained Earnings	1,113	586 D	527
Preferred and Preference Stock	292	168 D	124
Company Obligated Mandatorily Redeemable Preferred Securities of a Partnership	302		0 302
Long-Term Debt	4,186	1,681 D	2,505
	9,412	3,361	6,051
Current Liabilities			
Accrual for Bond Issuance and Refinancing		(277) B 24 C 253 D	
Total Current Liabilities	910	0	910
Deferred Credits and Other Liabilities			
Deferred Income Taxes	3,326		3,326
Unamortized Investment Tax Credits	341		341
Other	913	(143) B	1,056
	4,580	(143)	4,723
TOTAL	$ 14,902	$ 3,218	$ 11,684

Exhibit 2

Journal entries to record securitization:
(millions of dollars)

	DEBIT	CREDIT
(A) The following entry *would record* reclassification of plant assets to regulatory assets:		
Regulatory assets	2,435	
Net plant		2,435 (a)
(B) The following entry would record the sale of regulatory assets to the trust fund and application of a portion of the proceeds to current deferred fuel costs and the projected deferred fuel cost increase:		
Cash	3,600	
Restricted cash for transition bond issuance expenses	253 (b)	
Restricted cash for refinancing expenses	24 (b)	
Regulatory assets		3,361 (b)
Deferred fuel costs		96 (b)
Accrual for fuel costs		143 (b)
Accrual for bond issuance and refinancing expenses		277 (b)
(C) The following entry would record the payment of transition bond costs:		
Accrual for bond issuance expenses	24 (b)	
Restricted cash for refinancing expenses		24 (b)
(D) The following entry would be recorded to apply proceeds from the sale of regulatory assets to reduce capitalization and pay related costs:		
Long term debt	1,681 (c)	
Preferred stock	168 (c)	
Common stock	926 (c)	
Retained earnings	586 (c)	
Accrual for refinancing expenses	253 (b)	
Cash		3,361 (d)
Restricted cash for refinancing expenses		253 (b)

* A journal entry would also be recorded to reclassify regulatory assets of $926 that will be sold to the trust.

(a) See Exhibit TPH-6
(b) See Exhibit ACB-10, page 1 of 4
(c) Residual cash: 50% long term debt, 5% preferred stock, 45% common equity (see direct testimony of J.B. Mitchell - PECO Statement No. 4)
(d) Total cash proceeds minus fuel and issuance expenses

Exhibit 3

September 30, 1996 Income Statement
and Pro Forma Income Statement

Exhibit 3

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
UNAUDITED CONSOLIDATED STATEMENTS OF INCOME
(MILLIONS OF DOLLARS)

	12 months ended Sept. 30, 1996	proforma for add'l depreciation filing effective 10/1/96	12 months ended Sept. 30, 1996 adj'd for add'l depr.	proforma adjust.		12 Months ended Sept. 30, 1996 adjusted
Operating Revenues						
Total Operating Revenues	$ 4,314		$ 4,314	$ (658)	a	$ 3,656
Operating Expenses						
Fuel and Energy Interchange	935		935			935
Operation and Maintenance	1,320		1,320			1,320
Depreciation	466	$ 90	556	(168)	b	388
Income Taxes	360	(18)	342	(214)	c	128
Other Taxes	312		312	(3)	d	309
Total Operating Expenses	3393	72	3,465	(385)		3,080
Operating Income	921	(72)	849	(273)		576
Other Income and Deductions						
Total Other Income and Deductions	6		6			6
Income Before Interest Charges	927	(72)	855	(273)		582
Interest Charges						
Long term debt	345		345	(139)	e	206
MIPS	26		26			26
Other interest	48		48			48
AFUDC	(10)		(10)			(10)
Net Interest Charges	409	-	409	(139)		270
Net Income	518	(72)	446	(134)		312
Preferred Stock Dividends	18		18	(10)	f	8
Earnings Applicable to Common Stock	$ 500	$ (72)	$ 428	$ (124)		$ 304
Average shares outstanding	222.5		222.5	(58.6)	g	163.9
Earnings per average share	$ 2.25		$ 1.92			$ 1.85

a Reflects lower revenue resulting from securitization rate reduction. (See Exhibit ABC-10, page 1 of 4).

b Plant depreciation decreases with decrease in plant in service.
$385,475 (Exhibit ABC-7, page 5) X $2,435,158 (Exhibit TPH-6)/$6,714,898 (Exhibit ABC-7, page 2) = $139,793
Regulatory asset amortization decreases with decrease in regulatory assets, excl. FAS 109
$190,062 (Exhibit ABC-10, page 4) minus $113,062 (Exhibit ABC-10, page 4) X $2,435,158/$6,714,898 = $27,924
$139,793 + $27,924 = $167,712

c Income taxes decrease by:

decrease in net revenue	$ 95,357
decrease in gross receipts tax (GRT)	(3,056)
ITC payment	562,728
decrease in interest charges	(139,000)
	516,029
effective tax rate	41.493%
decrease in taxes	$ 214,116

d Net decrease in (GRT) ($658,085 X 4.4%) - $25,900 Exhibit ABC-10, page 1 of 4

e Decreased interest charges due to recapitalization. $1,681/$4,186 X $345,000 (ratio by change in Balance Sheet).

f Decreased Preferred Stock dividends due to recapitalization. $168/$292 X $18,000 (ratio by change in Balance Sheet).

g $1,512,000/$25.82 per share (assume $5 over book of $20.82) = 58,600 shares.

Exhibit 4

Securitization Transaction Schematic

PECO Energy

Securitization Transaction Schematic

Key Cash Flows

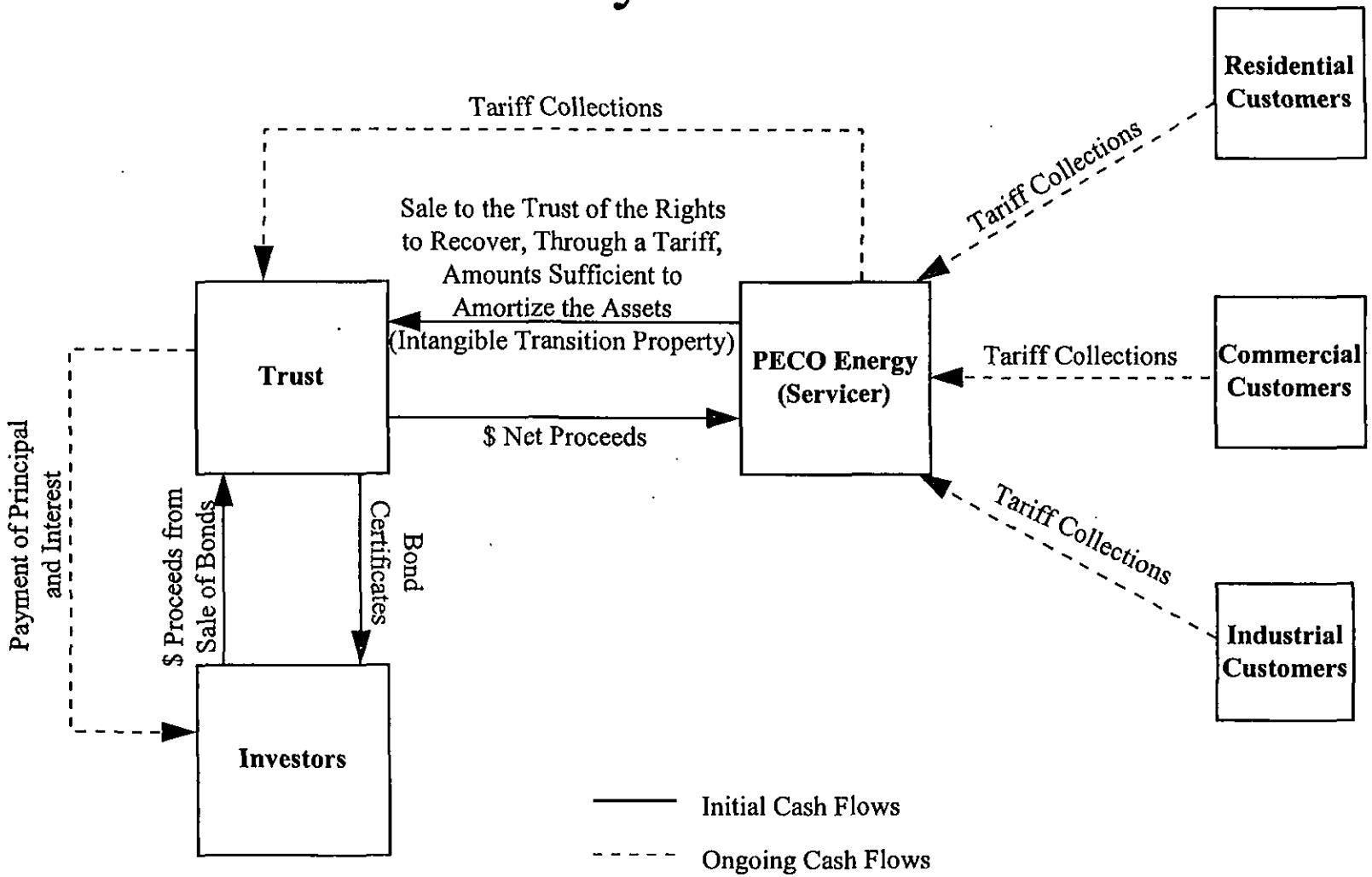


Exhibit 4

Exhibit 5

Testimony and Exhibits

PECO STATEMENT NO. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF A QUALIFIED RATE ORDER UNDER
SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY

OF

THOMAS P. HILL, JR.

Regarding Quantification Of PECO's
Stranded Costs And Its Securitization Proposal

TABLE OF CONTENTS

PAGE

DIRECT TESTIMONY OF THOMAS P. HILL, JR.

I. QUALIFICATIONS

Q. **Please state your name and business address.**

A. Thomas P. Hill, Jr., PECO Energy Company ("PECO"), 2301 Market Street, Philadelphia, PA 19103.

Q. **What is your current position at PECO?**

A. I am Vice President and Controller.

Q. **Please describe your educational background.**

A. I graduated from Lehigh University in 1970 with a B.S. in Industrial Engineering. I received my Master of Business Administration from Lehigh University in 1974. In 1986, I completed the Executive Development Program at Cornell University's Johnson Graduate School of Management.

Q. **Please outline your experience with PECO.**

A. Following my graduation from college in 1970, I joined PECO as an Engineer in the Rate Division. I held this position until 1978 when I was appointed Supervisor of Tariff and Special Projects within the Rate Division. In March of 1982, I was appointed Assistant Manager of the Rate Division and in March of 1986 Manager of the Rate Division. In 1990, I was appointed Controller and in 1991 I was elected to my current position as Vice President and Controller.

Q. **Please describe your responsibilities in your current position at PECO.**

A. As Vice President and Controller, I am the Chief Accounting Officer of the Company and am responsible for all the accounting, tax and regulatory functions. This includes development of policy in the above areas as well as assuring compliance with any governing regulations. Among those regulations are those issued by the Pennsylvania Public Utility Commission ("PUC" or the "Commission") and the Federal Energy Regulatory Commission ("FERC"), as well as agencies such as the Securities and Exchange Commission, the Financial Accounting Standards Board and all state and federal taxing authorities. Included within the regulatory function are all rate-related matters, whether at the PUC or the FERC.

Q. **Have you previously testified before the Commission?**

A. Yes. I have presented testimony in over 25 cases. A list of my prior appearances is set forth in Appendix A.

II. INTRODUCTION AND SUMMARY

Q. **Please describe the background and nature of this filing.**

A. On December 3, 1996, Governor Ridge signed into law the Electricity Generation Customer Choice and Competition Act (the "Electric Competition Act"). The Electric Competition Act fundamentally restructures the provision of retail electric service in Pennsylvania by mandating the phase-in of customer choice of generation supplier commencing January 1, 1999.

In enacting these changes, the Pennsylvania Legislature recognized that certain generation-related costs would not be recoverable in a competitive generation market. As a result, the Act establishes standards and creates mechanisms providing for the recovery of "transition" and/or "stranded" costs found by the Commission to be just and reasonable.[1/] Section 2803 of the Act defines the categories of such costs that are eligible for recovery, while Section 2808(C) sets forth the principles to be followed by the Commission in ruling on stranded cost claims.

The Act generally contemplates that such claims will be adjudicated in the context of comprehensive restructuring plans to be filed by Pennsylvania's electric utilities later this year. However, Section 2812 authorizes the issuance of "Qualified Rate Orders" in advance of the final approval of a utility's restructuring plan to facilitate the securitization of stranded costs.

Q. **Please describe the Qualified Rate Order process.**

A. Under Section 2812(A)(2), an electric utility may file an application for a Qualified Rate Order requesting that it be allowed to impose an "Intangible Transition Charge" ("ITC") covering its Qualified Transition Expense ("QTE") to recover all or a portion of its stranded costs. If approved, the irrevocable right to recover such costs, represented by the revenue stream to be produced by the ITC and denominated as "Intangible Transition Property", may then be sold or, alternatively, pledged or assigned as security. On the

---

1/ Except where necessary to differentiate between them, I will refer to these two categories jointly as PECO's stranded costs.

strength of the security provided by the Qualified Rate Order, the utility or a third party may issue "Transition Bonds". The proceeds of the sale or other financing of Intangible Transition Property can then be used to reduce the utility's stranded costs and/or related capitalization.

Q. **Will the sale and the financing of Intangible Transition Property trigger any change in retail rate levels?**

A. Yes. Because the Transition Bonds will be viewed as more creditworthy than PECO's traditional forms of securities such as corporate debt or first mortgage bonds, they will be issued at lower interest rates than PECO's existing capitalization, thereby reducing its overall cost of service. In addition, Section 2808(E)(2) of the Act provides that once Transition Bonds are successfully issued, the utility shall (1) impose the ITC(s) approved in the Qualified Rate Order and (2) simultaneously reduce its retail rates by an amount equal to the revenue requirement of the stranded costs for which the Transition Bonds have been issued.

Q. **Does the Electric Competition Act provide for expedited review of Qualified Rate Order applications?**

A. Yes. Under Section 2812(B) of the Act, a utility may request an accelerated determination of its request for a Qualified Rate Order, in which case the Commission must act within 120 days, but not earlier than fifteen days after the utility has filed its restructuring plan. Where expedited review is sought in advance of the utility filing its restructuring plan, however, the Commission may approve the issuance of Transition

Bonds for only a portion of the utility's stranded costs and is directed by the Act to defer consideration of all remaining amounts until the utility's restructuring plan proceeding.

Q. **What is PECO requesting in this proceeding?**

A. Based on analyses completed to date, PECO has determined that its net stranded costs, following mitigation, will approximate $7.1 billion. Through this filing, PECO is requesting that the Commission invoke the expedited review provisions of Section 2812(B) and issue a Qualified Rate Order, amongst other things, (1) finding that the recovery by PECO of approximately $3.9 billion in Qualified Transition Expenses, consisting, in part, of $3.6 billion of stranded costs and approximately $300 million of related financing expense, is just and reasonable, (2) concluding that the sale, assignment, transfer or pledge of the Intangible Transition Property created by the Qualified Rate Order and the issuance of Transition Bonds secured by such Intangible Transition Property is in the public interest and (3) approving the imposition of the ITC and corresponding rate decrease formulae, as well as the specific tariff revisions, set forth in Supplement No. 11 to Tariff Electric-Pa. P.U.C. No. 2.[2/]

Q. **What is the purpose of your direct testimony?**

A. I will first introduce the other witnesses who will appear on behalf of PECO in support of its request for a Qualified Rate Order. I will then describe the model utilized by PECO to calculate its stranded costs, identify the principal components of those costs and discuss

---

2/ Because generation-related costs are not allocated uniformly to PECO's various customer classes, different ITC factors and rate decreases have been calculated for each such class.

PECO's efforts to mitigate them. In the process, I will set forth PECO's specific proposal in this proceeding and will outline the accounting entries that would be made if that proposal were implemented. Next, I will explain why the relief sought by PECO is just and reasonable and in the public interest. Finally, I will briefly comment upon certain accounting and tax rulings that PECO hopes to obtain in order for the maximum benefits of this transaction to be realized.

III. INTRODUCTION OF OTHER WITNESSES

Q. **Please identify the other witnesses providing direct testimony on behalf of PECO in this proceeding.**

A. In addition to myself, the following witnesses will be responsible for presenting PECO's case-in-chief:

Alan B. Cohn is Manager of the Business Analysis and Support Section of PECO's Rates and Regulatory Affairs Division. Mr. Cohn quantifies the individual components of PECO's stranded costs. He also calculates the aggregate base rate decreases and ITCs resulting from the sale of Intangible Transition Property and issuance of Transition Bonds.

Stephen R. Xander is Manager of Tariff Administration and Policy in PECO's Rates and Regulatory Affairs Division. Mr. Xander utilizes the information provided by Mr. Cohn to develop individual customer class ITCs and Securitization Rate Reduction

charges. He also describes the procedures that PECO proposes to implement to reconcile ITC recovery and discusses other necessary tariff changes.

J. Barry Mitchell is PECO's Vice President of Finance and Treasurer. Mr. Mitchell describes the Company's proposal for the issuance of the Transition Bonds and explains how PECO plans to utilize the proceeds from the sale of Intangible Transition Property. He also provides an estimate of the financing costs that PECO will incur.

Howard L. Hiller is a Vice President in the Fixed-Income Capital Markets Group of Salomon Brothers Inc, an international investment bank. Mr. Hiller provides an overview of the market for asset-backed securities, in general, and the Transition Bonds, in particular. He also explains how the Transition Bonds will likely be structured and priced, relative to other, more commodity-like asset-backed securities

John J. Gillen is a Partner in the accounting firm of Coopers & Lybrand and serves as Chairman of that firm's Electric and Gas Industry Program. Mr. Gillen discusses the accounting and tax consequences of the proposed transaction.

John F. Bustard is a Senior Engineer in PECO's Bulk Power Enterprises group. Mr. Bustard presents the results of an analysis performed by the EDS Utilities Division and discusses analyses conducted by two other outside consultants to determine the prospective market price for power from each of the generating units in which PECO has an ownership interest.

Bangalore S. Venkateshwara is a Vice President of ICF Resources Incorporated, based in Fairfax, Virginia. Dr. Venkateshwara will present the results of an independent market clearing price analysis that he conducted at PECO's request.

William H. Hieronymus is a Managing Director of Putnam, Hayes & Bartlett Inc., an economic and management consulting firm based in Cambridge, Massachusetts. Like Dr. Venkateshwara, Dr. Hieronymus will present the results of an independent market clearing price analysis that he conducted at PECO's request.

IV. CALCULATION OF NET STRANDED COSTS

Q. **You previously testified that PECO has determined that its net stranded costs, following mitigation, will approximate $7.1 billion. How was that amount determined?**

A. The determination of PECO's net stranded costs, following mitigation, involves two components -- (1) the quantification of PECO's net electric generation-related costs, as estimated at December 31, 1998, and (2) the calculation of the market value of its investment in electric generating plants and facilities, as expressed in present value terms as of that same date.

Mr. Cohn, in his testimony, describes how PECO quantified its net electric generation-related costs at December 31, 1998. As he explains, the starting point was PECO's depreciated investment in generation plant (including construction work in progress) at December 31, 1996, plus certain generation-related regulatory assets. The resulting figure

was then projected forward to December 31, 1998, by factoring in capital additions anticipated during the 1997-98 period, as well as additional depreciation accruals and regulatory asset amortizations.

The foregoing steps yielded a sum of $9.147 billion. To this amount were added (1) the underfunded portion of PECO's projected nuclear generating plant decommissioning costs at December 31, 1998, and (2) the anticipated costs of retiring PECO's fossil fuel generating units. As summarized in Mr. Cohn's Exhibit ABC-1, PECO's net generation-related costs at December 31, 1998 are expected to be at least $9.704 billion.

Section 2808 also provides for the recovery of (1) existing purchase power obligations under contracts with non-utility generators; (2) nuclear spent fuel disposal costs; and (3) employee severance and retraining costs. These categories were treated as follows.

- **Existing Purchased Power Obligations Under Contracts with Non-Utility Generators.** As explained by Mr. Cohn in his testimony, the pricing of PECO's outstanding NUG contracts essentially tracks market price expectations. Accordingly, no stranded costs or stranded benefits relative to these contracts are anticipated.

- **Spent Fuel.** Unlike decommissioning expense, there is no known current underrecovery of spent nuclear fuel disposal costs. However, since these costs will continue to be incurred, they have been reflected in the calculation of the market value of PECO's nuclear units.

- **Employee Severance and Retraining Costs.** At this time, PECO does not project to incur any severance or retraining costs through the transition period and is therefore not claiming such costs as part of this filing. Based on the expenses incurred in connection with the Company's two most recent employee separation programs in 1990 and 1994, these costs can average as high as $102,000 to $130,000 per employee.

Q. **Please explain how PECO calculated the market value of its existing generating facilities.**

A. To estimate the value of its facilities in a competitive generation market commencing in 1999, PECO calculated the net margin which each generating unit could reasonably be expected to contribute over its remaining service life. A description of that analysis is set forth in Exhibit TPH-1.

In summary, the analysis starts with the market price which PECO's facilities would likely command in a competitive market. The market price projections for each unit for each hour and each year in question were derived from the studies discussed by Mr. Bustard and Drs. Venkateshwara and Hieronymus. Those values were then multiplied by the anticipated generation produced in each hour by each unit to develop an estimate of projected revenues per unit. Those market revenues were then reduced to reflect the costs of producing the power to yield a projected after-tax income stream for each unit for each year over its remaining service life. Those individual income streams, in turn, were restated on a present value basis as of December 31, 1998, by discounting the streams at PECO's after-tax cost of capital of 8.88%.[3/]

3/ Total Pre-Tax Cost Of Capital (15.7%) (Exhibit ABC-7, p. 4) x 1 - Effective Tax Rate (41.493%).

The foregoing process was followed to produce three separate market value projections -- one using the study presented by Mr. Bustard, one employing Dr. Venkateshwara's market price findings and one utilizing Dr. Hieronymus' figures.

The results of PECO's analysis using those three market value scenarios are set forth in Exhibits TPH-2 through TPH-4. Each of these Exhibits contains a presentation of the market value of each of PECO's generating stations on a present value basis and for each year that the unit would remain in base rates. In addition, the supporting information used in the analysis is contained in the subsequent pages of each package. This supporting information is provided for each station for each year. As previously mentioned, Exhibit TPH-1 contains a description of how these data are utilized to produce the present market values.

The average of those three present market values equals $2.568 billion, which, when subtracted from PECO's depreciated investment in generation plant of $6.514 billion, yields a stranded cost for generation plant of $3.946 billion. As set forth in Exhibit TPH-5, this figure, when combined with the other categories of PECO's stranded costs, results in a total stranded cost figure of $7.135 billion.

Q. **What assumptions were used in calculating the market values of PECO's generating units?**

A. A list of the major assumptions used by each of PECO's consultants may be found at pages 4-6 of Exhibits TPH-2 through TPH-4.

Q. **Does the $7.1 billion net stranded cost figure developed in Exhibit TPH-5 encompass all of PECO's stranded costs?**

A. I believe that it is a reasonable estimate of the known and measurable generation-related costs that would be recoverable in a regulated environment but may not be recoverable in a competitive electric generation market. Further analysis, however, may identify additional stranded costs. If that occurs, PECO will include those costs in its restructuring plan filing to be made later this year.

V. PECO'S SECURITIZATION PROPOSAL

Q. **Once it was determined that PECO's net stranded costs would approximate $7.1 billion, how did you develop the Company's specific request in this proceeding?**

A. I first asked Mr. Cohn to calculate the effect on customers' rates if the entire $7.1 billion were securitized. As he demonstrates in Exhibit ABC-9, the securitization of the full stranded amount would produce a net annual rate reduction of approximately $121 million, or approximately 3.7% assuming an effective interest rate on the Transition Bonds of 7.42%.

I then examined the individual components of PECO's stranded costs to identify items which either are included in the Company's existing rates or have been recognized by the Commission for future recovery. For example, PECO's investment in generating plant and certain regulatory asset amortizations are reflected in current rates and, therefore, that portion of its claim should not raise any controversy. On the other hand, PECO's

estimates of stranded nuclear decommissioning costs and costs to retire fossil generating plants are based on analyses which have not been subjected to regulatory scrutiny. Given the time constraints of this proceeding, I concluded that consideration of those items should await PECO's restructuring filing.

Q. **Why did you decide to request securitization of $3.6 billion of stranded costs?**

A. The $3.6 billion figure represents approximately one-half of PECO's projected stranded costs and, if securitized, will enable the Company to reduce retail rates by approximately $95 million per year, or 2.9%. PECO felt that it was important to provide a meaningful rate reduction up front in order to send a positive message to its customers and the greater business community that Pennsylvania's electric restructuring efforts are working. It must be noted, however, that the level of savings to customers is dependent upon the interest rate of the Transition Bonds, which, in turn, will be a function of the market conditions existing at the time of their issuance.

Q. **What comprises the $3.6 billion of stranded costs that PECO seeks to securitize through this filing?**

A. The $3.6 billion consists of (1) $239 million of deferred fuel costs and (2) $3.36 billion, representing a pro rata slice of (a) PECO's stranded investment in generating facilities and (b) other regulatory assets for which rate recovery has already been approved. A breakdown of the $3.6 billion figure is set forth in Exhibit TPH-6. In addition, and as noted in the Application, PECO is seeking to securitize approximately $277 million of financing costs.

Q. **You previously indicated that approval of the Application would enable PECO to reduce its retail rates by approximately $95 million, or 2.9%, per year. How would that rate reduction be allocated amongst PECO's retail rate classes?**

A. The allocation of the proposed rate reduction is developed by Mr. Cohn and converted into specific adjustment factors by Mr. Xander. Our major rate classes will receive rate reductions and associated percentage decreases as follows:

RATE CLASS	RATE REDUCTIONS (MILLION $)	RATE REDUCTION(%)
R (RESIDENTIAL)	27.9	2.7
GS (SMALL COMMERCIAL)	19.7	2.6
HT (LARGE INDUSTRIAL)	37.2	3.7
ALL OTHER	10.4	VARIOUS

Q. **If PECO's securitization proposal is approved, what impact would the anticipated transactions have on the Company's financial statements?**

A. The effects of the proposed securitization on PECO's balance sheet and income statement are shown on Exhibits 2 and 3 to the Application. More specifically, Exhibit 2 sets forth PECO's balance sheet at September 30, 1996 (calendar year-end financial data has not yet been publicly disclosed), the journal entries necessary to reflect the securitization and

the resulting pro forma figures. Similar data relating to PECO's statement of income is presented on Exhibit 3. The accounting entries were reviewed by Mr. Gillen and found to be appropriate.

VI. MITIGATION AND COST CONTAINMENT

Q. **What steps has PECO taken to mitigate its stranded costs and/or to moderate its retail rate levels?**

A. PECO has taken a number of significant steps to mitigate its stranded costs and to moderate rate levels. Specific mitigation initiatives may be summarized as follows:

Accelerated Depreciation Of Limerick Station. In a Petition filed on October 27, 1995 at Docket No. P-00950982, PECO proposed that the terminal (i.e. retirement) date of the Limerick Station be advanced by ten years for accounting purposes and that the additional annual depreciation accruals be deemed subsumed in its existing base rates. This acceleration of cost recovery, which was approved by the Commission in an Order entered February 23, 1996 (a copy of the Commission's Order has been attached to my testimony as Exhibit TPH-7), serves to reduce PECO's investment in the Limerick Station by approximately $71.8 million per year and by a total of $161.6 million by December 31, 1998.

Accelerated Amortization Of Deferred Limerick Station Common Plant Costs. When the Commission established rates in PECO's Limerick 1 rate proceeding, it excluded, as a matter of Pennsylvania regulatory policy, 50% of Limerick common plant

pending the completion of Limerick 2. At the same time, the Commission permitted PECO to continue to accrue an Allowance For Funds Used During Construction ("AFUDC") on and to defer depreciation with respect to the excluded portion of common plant. Subsequently, in PECO's Limerick 2 rate proceeding, the additional AFUDC accruals and deferred depreciation, which had been booked to FERC Account 186 as regulatory assets, were amortized over the 40-year licensed life of the Limerick 2 Station.

In the October 27, 1995 Petition referenced earlier, PECO proposed to accelerate, for accounting purposes, the recovery of these assets by amortizing the balance over a nine-year period commencing October 1, 1996. As in the case of the accelerated depreciation of the Limerick Station, PECO further requested that the additional annual amortization totaling $18.2 million be deemed recoverable through existing rates. This proposal, which was also approved by the Commission in its February 23, 1996 Order, will serve to reduce the costs which otherwise would have been stranded by $40.9 million by December 31, 1998.

Accelerated Amortization Of Limerick 2 "Early Window" Costs. By Order entered May 3, 1989 at Docket No. P-890349, the Commission authorized PECO to defer recognition of the net costs (carrying charges, operating and maintenance expenses and related taxes, less fuel savings) that it would incur in the "early window" period between the placement in service of Limerick 2 and the inclusion of the costs of that facility in retail rates. The Commission further noted that the ratemaking treatment of such early window costs would be adjudicated in an appropriate proceeding subsequent to PECO's

Limerick 2 rate case. Limerick 2 was declared to be in commercial operation on January 8, 1990; the rates established in the Limerick 2 rate case became effective on April 20, 1990.

In the October 27, 1995 Petition, PECO proposed to amortize its Limerick 2 early window costs, which approximated $90.6 million, over a nine-year period commencing October 1, 1996. As with the other items discussed previously, PECO requested, and the Commission agreed, that the annual amortized amount of $10.1 million be considered subsumed in existing rates. This additional amortization will reduce PECO's stranded costs by $22.7 million by December 31, 1998.

Minimization Of New Capital Spending For Existing Rate Base Generation Assets. During the 1990s, PECO has significantly cut back its spending on existing generating facilities. As shown in Exhibit TPH-8, PECO managed to curtail annual generation-related capital additions for the period 1992-1996 by $218 million from the levels projected only eight years ago. To some extent, this may be viewed as a natural response to the Company's commitment, made subsequent to the Limerick 2 rate case, to maintain existing rate levels through at least 1999. More recently, however, the moderation in capital spending can be traced to a strategic decision to mitigate costs in anticipation of competition. In fact, PECO has established even more aggressive goals for capital spending in 1997, which are almost 60% lower than 1995 actual levels. The aggressive 1997 figures have been used as the basis for future capital projections in the Company's

stranded investment analysis, thereby resulting in lower stranded costs. To the extent that these aggressive targets are not achieved, the impact will be borne by shareholders.

Reallocation Of Depreciation Reserves. PECO is analyzing the possible reallocation to existing generation assets of depreciation reserves presently assigned to its distribution facilities. If current service life estimates support such a reallocation of reserves, PECO will include that proposal in its restructuring filing as a means to further mitigate its stranded costs.

Maximization Of Market Revenues From Existing Generating Assets. PECO has sought to maximize the value of its existing generating facilities, and thereby mitigate its potential stranded costs, by substantially improving the efficiency of the units which it operates. In particular, PECO has reduced dramatically the outage time, both scheduled and unscheduled, at its Limerick and Peach Bottom Stations and has successfully converted all of the nuclear facilities which it operates to a twenty-four month refueling cycle. In fact, PECO currently holds the world record for the shortest, most efficient refueling outage of a General Electric designed boiling water reactor (Peach Bottom Unit 2, 19 days). As a consequence, the capacity factors achieved by the Limerick and Peach Bottom units in recent years have been exemplary:

ANNUAL CAPACITY FACTORS				
	LIMERICK		PEACH BOTTOM	
	No. 1	No. 2	No. 2	No.3
1991	88.0%	77.3%	54.9%	56.4%
1992	67.2%	91.6%	61.3%	79.0%
1993	94.6%	80.7%	83.5%	69.0%
1994	85.0%	92.7%	80.8%	97.8%
1995	88.2%	86.7%	98.0%	79.1%
1996	83.9%	91.9%	79.8%	98.2%

These figures far exceed PECO's capacity factor projections in the Limerick 2 rate proceeding of 65%.

The same may be said for PECO's fossil steam units. PECO managed to increase availability factors from 79% in 1992 to 84% in 1996. Also, PECO has increased the capacity factors of its coal units from 40% to 70% over the same period.

As I discussed previously, the market value of PECO's generating facilities is, in part, a function of how well they run. Stated simply, the more kilowatt-hours they are capable of producing, the greater their value in a competitive generation market. By enhancing their market value through increased efficiencies, PECO has, in turn, mitigated costs that might otherwise have been stranded. In addition, it should be noted that PECO has been able to add over 400 megawatts of generating capacity through extremely cost-effective unit uprates.

Issuance Of Securitized Debt. By this filing, PECO is seeking to reduce its stranded costs by $3.6 billion as shown in Exhibit TPH-6, while currently reducing rates to customers by approximately 2.9%. Moreover, by utilizing debt which must be paid off in ten years (i.e., the Transition Bonds), PECO will effectively accelerate the depreciation/amortization of its stranded assets, some of which have remaining lives of twenty years or more.

A. **Did PECO take any other action prior to the enactment of the Electric Competition Act to moderate retail rate levels?**

Yes. In fact, PECO has been extremely vigilant over the past several years in seeking out ways to contain and, where possible, reduce costs, while maintaining safe and efficient operations. The following examples should suffice to illustrate the point:

- **Workforce Reductions.** PECO has initiated substantial workforce reductions such that its present employee complement is now some 37% less than it was in 1990. PECO's nuclear employee levels have declined by 28% while fossil generation staffing levels have dropped by 67%. A significant portion of those workforce reductions were accomplished through extensive process reengineering programs which enable PECO to increase the productivity of its generating facilities while, at the same time, reducing operating and maintenance costs.

  In addition, PECO has set aggressive operating and maintenance expense targets for 1997 which are approximately 6% lower than 1995 levels in real terms (inflation is expected to be 4% over this period). As in the case of capital additions, these targets were utilized in PECO's stranded cost analysis and, if not achieved, the impact will be borne by shareholders.

- **Healthcare/Post-Retirement Benefit Costs.** PECO has engaged in substantial efforts to control benefit levels and health care costs since

1990, including the implementation of employee and retiree cost-sharing for medical insurance and the renegotiation of insurance contracts.

- **Fuel Costs.** PECO has significantly reduced its fuel costs by renegotiating delivered coal and uranium contracts, acquiring nuclear fuel from the Shoreham plant, maximizing spot market purchases and converting its Cromby and Eddystone units so that they can utilize either oil or natural gas as their primary fuel. In fact, PECO reduced its average cost of fuel from 1.58 cents per kilowatt-hour in 1990 to 1.16 cents per kilowatt-hour in 1995, a reduction of approximately 27%. These benefits were passed on to customers through periodic adjustments to PECO's energy cost rate mechanism.

- **Inventory Reductions.** Since the Limerick 2 rate case, PECO has reduced materials and supplies inventories by 23% in real terms (inflation approximated 17.4% over this period). This was accomplished through the elimination of obsolete and excess materials and changes in stocking levels.

- **Refinancing Of Higher Cost Debt.** PECO has taken full advantage of declining interest rates by refinancing over $6.2 billion of long-term debt since 1990, producing annualized interest cost savings of approximately $252 million.

- **Retention Of Customer Load.** PECO has been innovative in developing flexible rate offerings designed to retain existing industrial load and to promote economic development. These flexible rates have resulted in revenue retention in excess of $30 million on an annualized basis.

Q. **How have these initiatives served to moderate retail rate levels?**

A. PECO has been able to use the savings generated in certain areas of its operations to offset the unavoidable rise in expenses in other areas, including the effects of inflation on labor and materials costs. As a result, and as shown in Exhibit TPH-9, PECO's operating expenses (exclusive of fuel) have significantly declined in real terms on a per kilowatt-hour basis over the past six years. Because of this, PECO has not filed for a general rate

increase since 1989 and, indeed, agreed in 1994 that it would not file for such an increase until April 1, 1999 at the earliest. This extended rate moratorium is a tribute to PECO's determined efforts to contain costs and to stabilize or reduce costs to customers.

VII. STATUTORY STANDARDS

Q. **Sections 2804 and 2812 of the Electric Competition Act require that the Commission find that the recovery of stranded costs is "just and reasonable". Why, in your view, does PECO's claim satisfy that standard?**

A. Because denial of PECO's request in this proceeding would be demonstrably unjust and unreasonable. I firmly believe that, in this proceeding and in the forthcoming restructuring filing, PECO will establish its entitlement to full recovery of its stranded costs. However, the Commission need not address that broader issue in this case and, in fact, is explicitly directed by the Electric Competition Act to defer, until a utility's restructuring plan proceeding, consideration of stranded costs for which approval to issue Transition Bonds has not been sought.

With that caveat, there can be no doubt that the specific costs which PECO is seeking to securitize at this time would be recoverable under a regulated environment. In fact, the various regulatory assets encompassed by PECO's stranded cost claim either are currently being amortized through existing rates or have been recognized by the Commission for future recovery.

Q. **Does the same hold true for PECO's investment in electric generating facilities?**

A. Most certainly. All of PECO's existing generating facilities were constructed in furtherance of its statutory obligation to serve the current and future needs of its customers in its service territory. Moreover, as long as that obligation to serve remains in place, those facilities will continue to be required to satisfy customer demands.

Under what is commonly referred to as the "regulatory compact", utilities, like PECO, have made substantial investments in facilities and infrastructure necessary to satisfy their statutory obligations and have further agreed to accept governmentally-imposed limitations on the prices they can charge. In return, they were granted a protected and essentially exclusive franchise and the assurance of an opportunity to recover their prudent investments together with a reasonable return on them over periods of time established by the Commission in its prior rate orders. The symmetry of these corresponding rights and obligations would obviously be destroyed if, under the banner of promoting competition, the Commission were to deny recovery of PECO's prudent investments. Such a result would not only constitute a fundamentally inequitable change in the rules of the game, but would be confiscatory.

Q. **Has the Commission previously ruled on the prudence of PECO's investment in its existing generating facilities?**

A. Yes, it has. Between 1968 and 1990, PECO filed 13 separate requests for base rate relief. In each of those cases, the Commission was called upon to determine the level of investment on which PECO would be allowed to earn a return. For example, with respect

to the Limerick Station, PECO's actions were reviewed on no less than five separate occasions. Indeed, I am aware of no other construction project that has experienced the level of regulatory scrutiny that the Limerick project endured over the years. As noted in the summary of those proceedings, which may be found in Exhibit TPH-10, PECO shareholders have already been required to absorb nearly $600 million of the costs of constructing Limerick.

Q. **Please summarize your position with respect to the justness and reasonableness of PECO's claim for recovery of stranded costs in this proceeding.**

A. The stranded costs that PECO has identified represent either expenditures that it unquestionably would be allowed to recover absent the introduction of competition or prudent investments in electric generating facilities that are used and useful in satisfying its statutory obligation to serve. In addition, and as noted previously, PECO has taken substantial steps to mitigate its stranded costs and to moderate rate levels. PECO's claim in this proceeding equates to only approximately 50% of its total stranded costs and should, therefore, be approved.

Q. **Assuming that the Commission concludes that PECO's request for stranded cost recovery is just and reasonable, why should it further find that the securitization of that amount at this time is in the public interest?**

A. For several reasons. First, and as described by Mr. Cohn, securitization will trigger a rate reduction of approximately $95 million, or 2.9%, per year, which will send a positive signal to PECO's customers that electric restructuring can produce positive benefits.

Second, and as pointed out by Messrs. Mitchell and Hiller, there are cost savings to be achieved in securitizing a portion of PECO's stranded costs sooner rather than later. By getting to the capital markets early, PECO will be able to take advantage of the relatively low interest rates prevailing today and, at the same time, mitigate its exposure to the potential excess supply of bonds that may occur as other utilities seek to finance stranded costs in anticipation of retail competition. The resulting cost savings, in turn, will translate into lower ITCs to be assessed to customers.

The approval of PECO's request will also eliminate some of the uncertainty surrounding the Commonwealth's restructuring efforts. The business and investment communities will most certainly be following this proceeding as a barometer of the future financial health of Pennsylvania's electric utilities. In this regard, it must not be forgotten that Pennsylvania's jurisdictional utilities will continue to provide vital transmission and distribution services and, for at least some period of time, may be required to function as the generation supplier of last resort.

Finally, approval of the Company's request in this case would signal that businesses which invest in Pennsylvania can expect to be treated fairly. That message, together with the immediate rate decrease that would be put in place following the issuance of Transition Bonds, can only help to further promote Governor Ridge's goal of spurring economic growth and job creation.

VIII. ACCOUNTING AND TAX RULINGS

Q. **What additional rulings will PECO require before it moves forward with the proposed securitization?**

A. In order for the proposed securitization to produce the maximum positive benefits for PECO's customers and shareholders, the transfer of Intangible Transition Property must be considered a "sale" for book purposes, but as a "financing" for tax purposes so that PECO is not required to immediately recognize income. In his testimony, Mr. Gillen explains why, in his opinion, the transaction, as currently contemplated, should qualify as a sale of financial assets under Statement of Financial Accounting Standards No. 125, subject to SEC approval. As he and Mr. Mitchell further discuss, PECO intends to file shortly for a private letter ruling from the Internal Revenue Service to confirm that the proposed sale of Intangible Transition Property will not be treated as a taxable event for PECO.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

PRIOR EXPERIENCE OF THOMAS P. HILL, JR.

Q. Would you outline your prior experience in preparing rate filing materials and testimony given in rate proceedings?

A. I have participated in the preparation of rate case materials necessary for filing electric rate applications before the Pennsylvania Public Utility Commission which include: the 1975 Electric Rate Case (RID 295), the 1977 Electric Rate Case (RID 438), the 1979 Electric Rate Case (R-79060865), the 1980 through 1985 Electric Rate Cases (R-8006125, R-811626, R-822291, R-842590 and R-850152), and the 1989 Limerick Generating Station Electric Rate Case (R-891364). At R-79060865, I submitted testimony in the area of nuclear fuel inventory, materials and supplies, land held for future use and non-revenue producing CWIP. At R-8006125, R-811626, R-822291, R-842590 and R-850152, I presented testimony on specific revenue adjustments, operating expenses and the Company's claimed rate base exclusive of depreciated plant in service. At R-891364, I presented the Company's overall claim, as well as specific revenue adjustments.

In addition, I have participated in the preparation of similar materials in prior Gas Operations filings including the 1979 Gas Rate (R-79030781), the 1981 Gas Rate Case (R-811719), the 1983 Gas Rate Case (R-8432410) and the 1987 Gas Rate Case (R-870629). At R-79030781, I presented testimony as the Company depreciation witness responsible for claimed rate base and

presented testimony in support of the Company's revenue claim, operating expenses and rate base exclusive of depreciated plant in service.

Q. I have participated in the preparation of rate filing materials for the prior Steam Operations filings including the 1979 Steam Rate Case (R-79040785), the 1980 Steam Rate Case (R-80071263), the 1981 Steam Rate Case (R-811720), the 1982 Steam Rate Case (R-822101) and the 1983 Steam Rate Case (R-832434). At R-79040785, I presented testimony as the Company depreciation witness responsible for rate base and annual provisions for depreciation. At R-80071263, I presented testimony in support of the Company's claims for materials and supplies and cash working capital. At R-822101 and R-832434, I presented testimony supporting the Company's claims for all revenue and expenses.

I have participated since 1970 in the preparation of exhibits for rate base, revenue, expense and other adjustments necessary for filing rate applications before the Federal Energy Regulatory Commission in support of our rate increases to the Borough of Lansdale and Conowingo Power Company. I have submitted testimony before the FERC at Dockets ER81-318, ER82-294, ER82-295, ER84-910, ER86-622 and ER94-8-000. I have also prepared rate filing material including rate base and all adjustments to rate base for filings before the Public Service Commission of Maryland for our subsidiary Conowingo Power Company.

Finally, I have submitted testimony in several Show Cause proceedings before the Pennsylvania Public Utility Commission. At Dockets No. R-830453, No. M-840375, No. M-850010, and No. I-880082 I testified on the administration of the Company's Energy Cost Rate and at Docket No. I-840381, I testified on the revenue requirements for Limerick 2 and other alternate generation scenarios.

PECO Energy Company
Calculation of Net Stranded Cost

Exhibit TPH-1

Summary

Stranded Investment is calculated by subtracting the present value of the after-tax contribution margin for PECO Energy's generating units at December 31, 1998 from the net book value of electric generation-related assets as of that date. The model identifies the various operating cost and generation characteristics for each of PECO's generating units. By calculating the operating cost for each unit and comparing this to the projected operating revenue of the unit, one is able to determine which units are able to run and recover their costs and those that will not. The excess of generating assets over the discounted margin stream will not be recoverable in a competitive environment and is, therefore, stranded investment.

Generating Assets Subject to Stranded Investment

The generation-related assets subject to stranded investment include net generation plant, construction work in process and net regulatory assets, but exclude that portion of the Limerick plant that was previously disallowed from rate base. The asset values are based on year end 1996 book figures projected to December 31, 1998.

Net Present Value of After-Tax Contribution Margin

The after-tax contribution margin is defined as operating revenue less fuel cost, including spent fuel disposal costs, operating and maintenance expense, ongoing capital expenditures, administrative and general expense, other taxes, decommissioning costs, and required life extension costs. A margin is calculated for each station in the portfolio on a year-by-year basis and multiplied by one minus the tax rate to arrive at an after-tax income stream. However, if the calculated after-tax margin for a station unit in any year is less than zero, then the model performs a second calculation to determine if the plant should operate. Although a plant may not run, it may still incur certain costs such as other taxes and decommissioning costs. To maximize the value of the station in the net present value calculation, the margin used for a station in any year is the greater of these two calculations. The margin is further adjusted to reflect the present value of the carrying charges of working capital and inventory as well as future tax depreciation benefits of the capital additions, the value of accumulated deferred investment tax credits and the value of accumulated deferred income taxes.

The margin stream is discounted to December 31, 1998 using a discount rate of 8.88% which is PECO's weighted average cost of capital. The tax rate used in the analysis is 41.493% which is PECO's current and projected composite federal and state income tax rate.

The analysis assumes that PECO's nuclear units will continue to operate (assuming they are economic) through the end of their license lives. All other units are assumed to operate through the end of their service lives but may receive a life extension of 15 years if it is economic to do so.

Revenue Projection

Operating revenue is calculated for each generating station in the Company's portfolio. The revenue is derived by multiplying the projected generation for that station during each hour by the projected market price for that hour. The generation and the market price projections were derived from analyses conducted by outside consultants engaged by PECO. The market prices provided are in 1996 dollars and are inflated using the GDP deflator published by DRI/McGraw-Hill World Energy Service, U.S. Outlook, Fall/Winter 1996-97, October 1996. The DRI data is based on US Macroeconomic Service Trend25yr0896.

Fuel Cost Projection

Fuel costs for the fossil stations are based on projections of unit fuel costs provided by the consultants engaged by PECO. Fuel costs for the nuclear units are based on projections made by PECO Nuclear and include spent fuel disposal costs. Fuel expense is derived by multiplying projected generation in megawatt hours against a projected unit fuel cost for each station in the portfolio. The fossil station fuel costs are in 1996 dollars inflated using the DRI/McGraw-Hill GDP deflator. The nuclear unit fuel costs are in 1997 dollars inflated using the DRI GDP deflator.

Operating and Maintenance Expense

Operating and Maintenance expense (O&M) is based on PECO's internal projections on a station by station basis. O&M expenses are in 1997 dollars inflated using the DRI/McGraw-Hill GDP deflator.

Ongoing Capital Expenditures

Ongoing capital expenditures are based on PECO's internal projections on a station by station basis and are in 1997 dollars inflated using the DRI/McGraw-

Hill GDP deflator. Capital expenditures for Limerick reflects the carrying charges of nuclear fuel inventory.

Administrative and General Expenses

Administrative and General (A&G) expenses are based on 1995 actual results. A&G is composed of two accounts – Employee Pension and Benefits and Property Insurance. Employee Pension and Benefits is allocated to generation based on labor expense. Property insurance is allocated to generation based on net plant. A&G expenses are then allocated to each station based on estimated 1997 O&M expense. The Conemaugh, Keystone and Salem O&M figures already include allocated A&G expense and therefore do not receive any additional allocation. A&G expenses are in 1995 dollars inflated using the DRI/McGraw-Hill GDP deflator.

Other Taxes

Other taxes are based on 1995 actual results and include taxes other than income taxes adjusted to exclude gross receipts tax. A portion of other taxes is allocated to generation based upon plant, the remainder is allocated based upon labor. Other taxes are allocated to each station based on estimated 1997 O&M expense. Similar to A&G costs, the Conemaugh, Keystone and Salem units do not receive an additional allocation as these costs are already included in their base O&M. Other taxes are in 1995 dollars and continue at fixed levels for the remaining lives of the units.

Decommissioning

Decommissioning costs for the nuclear units are based on site specific decommissioning studies as described in the testimony of A. B. Cohn and continue at fixed levels for the remaining lives of the units. Decommissioning costs for the fossil units are based on internal estimates and continue at fixed levels for the remaining lives of the units.

Required Life Extension Costs

Required life extension costs for the non-nuclear units are based on site specific estimates as made by PECO. These estimates are in 1997 dollars inflated using the DRI/McGraw-Hill GDP deflator. Life extension costs are incurred only if it is economic to do so.

Net Present Value of Contribution Margin

EDS - Utilizing J. Bustard's Market Revenue Estimates

Plant Name	(000) Net Present Value
Conemaugh	$ 273,655
Conowingo	529,196
Cromby 1	(9,017)
Cromby 2	(542)
Delaware	(604)
Eddystone 1	(18,961)
Eddystone 2	(1,298)
Eddystone3&4	32,093
Keystone	189,402
Limerick 1	295,283
Limerick 2	324,588
Muddy Run	177,426
P. Bottom 2	53,152
P. Bottom 3	57,886
Salem 1	10,994
Salem 2	20,605
Schuylkill	135
C. Turbines	40,064
Total NPV of Contribution Margin	**$ 1,974,058**
Total NPV excluding Negative Values	**$ 2,004,480**
Inventory and Working Capital Carrying Charges	(162,363)
Future Tax Depreciation Benefits	270,512
Accumulated Deferred Investment Tax Credit Benefits	133,360
Deferred Income Tax	400,598
Total Adjusted NPV excluding Negative Values	**$ 2,646,587**

Exhibit TPH-2

Market Value of Generating Units by Year

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Net Present Value	$1,974,058	$273,655	$529,196	($9,017)	($542)	($604)	($18,961)	($1,298)	$32,093	$189,402

(Market Value Revenue - Est. Fuel Cost - Est. O&M - Est. Capital - A&G - Taxes - Decomm. - Required Life Extension*) x (1-T)*

*After-Tax Cash Contribution Margin***				***						
1999	$ 37,746	$ 17,058	$ 25,805	$ (2,003)	$ (590)	$ (658)	$ (3,729)	$ (3,216)	$ 3,218	$ 11,992
2000	$ 89,781	$ 19,561	$ 29,233	$ (2,003)	$ -	$ -	$ (3,729)	$ (3,216)	$ 5,870	$ 14,437
2001	$ 105,695	$ 21,168	$ 31,516	$ (2,003)	$ -	$ -	$ (3,729)	$ (2,831)	$ 5,487	$ 16,044
2002	$ 123,825	$ 23,241	$ 33,171	$ (2,003)	$ -	$ -	$ (3,729)	$ (1,812)	$ 5,634	$ 17,921
2003	$ 95,660	$ 25,295	$ 36,057	$ (2,003)	$ -	$ -	$ (3,729)	$ (1,557)	$ 5,588	$ (31,566)
2004	$ 174,369	$ 27,733	$ 38,870	$ (2,003)	$ -	$ -	$ (2,933)	$ (168)	$ 5,039	$ 22,250
2005	$ 211,368	$ 30,532	$ 41,617	$ -	$ -	$ -	$ (1,324)	$ 1,618	$ 5,870	$ 25,122
2006	$ 153,409	$ (25,577)	$ 44,282	$ -	$ -	$ -	$ (1,442)	$ 1,539	$ 4,693	$ 25,721
2007	$ 234,273	$ 33,140	$ 49,499	$ -	$ -	$ -	$ (533)	$ 2,584	$ 4,090	$ 27,478
2008	$ 231,825	$ 34,090	$ 48,485	$ -	$ -	$ -	$ (670)	$ 2,557	$ 2,581	$ 28,233
2009	$ 234,184	$ 35,088	$ 50,616	$ -	$ -	$ -	$ (778)	$ 2,524	$ 1,093	$ 28,963
2010	$ 194,452	$ 36,033	$ 56,672	$ -	$ -	$ -	$ (972)	$ (42,055)	$ 567	$ 29,826
2011	$ 261,508	$ 37,984	$ 59,411	$ -	$ -	$ -	$ -	$ 3,180	$ -	$ 31,565
2012	$ 281,763	$ 39,988	$ 62,212	$ -	$ -	$ -	$ -	$ 3,875	$ -	$ 33,349
2013	$ 303,960	$ 42,102	$ 65,157	$ -	$ -	$ -	$ -	$ 4,649	$ -	$ 35,236
2014	$ 279,790	$ 44,333	$ 58,240	$ -	$ -	$ -	$ -	$ 5,503	$ -	$ 37,232
2015	$ 310,156	$ 46,686	$ 71,508	$ -	$ -	$ -	$ -	$ 6,443	$ -	$ 39,342
2016	$ 324,122	$ 48,491	$ 74,299	$ -	$ -	$ -	$ -	$ 6,811	$ -	$ 40,868
2017	$ 330,340	$ 50,295	$ 77,090	$ -	$ -	$ -	$ -	$ 7,178	$ -	$ 42,393
2018	$ 343,977	$ 52,100	$ 79,880	$ -	$ -	$ -	$ -	$ 7,546	$ -	$ 43,919
2019	$ 313,900	$ 54,162	$ 83,070	$ -	$ -	$ -	$ -	$ 7,966	$ -	$ -
2020	$ 327,742	$ 56,225	$ 86,260	$ -	$ -	$ -	$ -	$ 8,386	$ -	$ -
2021	$ 332,488	$ 58,364	$ 89,569	$ -	$ -	$ -	$ -	$ 8,822	$ -	$ -
2022	$ 286,400	$ -	$ 93,003	$ -	$ -	$ -	$ -	$ 9,274	$ -	$ -
2023	$ 299,139	$ -	$ 96,566	$ -	$ -	$ -	$ -	$ 9,743	$ -	$ -
2024	$ 312,355	$ -	$ 100,262	$ -	$ -	$ -	$ -	$ 10,229	$ -	$ -
2025	$ 236,505	$ -	$ 104,098	$ -	$ -	$ -	$ -	$ 10,734	$ -	$ -
2026	$ 235,264	$ -	$ 108,077	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 245,115	$ -	$ 112,206	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 255,336	$ -	$ 116,490	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 265,940	$ -	$ 120,935	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

** Assumes all capital additions are currently tax deductible. Capital also includes required life extension costs.*

*** If contribution margin is negative then plant does not operate, but incurs taxes and decommissioning costs.*

**** Shaded areas indicate plant does not operate.*

Market Value of Generating Units by Year

EDS - Utilizing J. Bustard's Market Revenue (000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Net Present Value	$295,283	$324,588	$177,426	$53,152	$57,886	$10,994	$20,605	$135	$40,064
After-Tax Cash Contribution Margin						***			
1999	$ (647)	$ (1,830)	$ 7,052	$ (2,782)	$ (2,779)	$ (1,536)	$ (1,135)	$ 147	$ (6,623)
2000	$ 6,811	$ 5,628	$ 10,398	$ 489	$ 493	$ (1,536)	$ (1,135)	$ -	$ 8,481
2001	$ 10,025	$ 8,842	$ 11,774	$ 1,994	$ 1,997	$ (1,536)	$ (1,135)	$ -	$ 8,083
2002	$ 13,306	$ 12,124	$ 13,518	$ 3,434	$ 3,437	$ (1,536)	$ (1,135)	$ -	$ 8,254
2003	$ 17,798	$ 16,615	$ 15,746	$ 5,367	$ 5,370	$ (666)	$ (264)	$ -	$ 7,610
2004	$ 22,543	$ 21,361	$ 17,919	$ 7,329	$ 7,332	$ 839	$ 1,241	$ -	$ 7,019
2005	*$ 28,151*	*$ 26,969*	*$ 19,843*	*$ 9,638*	*$ 9,642*	*$ 2,684*	*$ 3,095*	*$ -*	*$ 7,900*
2006	$ 28,447	$ 27,264	$ 17,557	$ 9,728	$ 9,731	$ 2,214	$ 2,616	$ -	$ 6,636
2007	$ 33,189	$ 32,006	$ 15,602	$ 11,691	$ 11,695	$ 3,721	$ 4,123	$ -	$ 5,987
2008	$ 33,486	$ 32,303	$ 16,049	$ 11,768	$ 11,771	$ 3,200	$ 3,602	$ -	$ 4,370
2009	$ 34,251	$ 33,068	$ 16,403	$ 12,012	$ 12,015	$ 2,876	$ 3,278	$ -	$ 2,774
2010	*$ 34,303*	*$ 33,120*	*$ 16,297*	*$ 11,939*	*$ 11,942*	*$ 2,086*	*$ 2,488*	*$ -*	*$ 2,204*
2011	$ 38,358	$ 37,175	$ 17,453	$ 13,578	$ 13,582	$ 3,150	$ 3,552	$ -	$ 2,520
2012	$ 41,957	$ 40,774	$ 18,622	$ 15,009	$ 15,012	$ 3,887	$ 4,288	$ -	$ 2,790
2013	$ 45,934	$ 44,751	$ 19,868	$ 16,599	$ 16,602	$ 4,784	$ 5,186	$ -	$ 3,093
2014	$ 50,304	$ 49,121	$ 1,167	$ -	$ 18,359	$ 5,850	$ 6,251	$ -	$ 3,429
2015	$ 55,086	$ 53,903	$ 22,606	$ -	$ -	$ 7,090	$ 7,492	$ -	$ -
2016	$ 58,038	$ 56,855	$ 23,521	$ -	$ -	$ 7,419	$ 7,820	$ -	$ -
2017	$ 60,991	$ 59,808	$ 24,436	$ -	$ -	$ -	$ 8,148	$ -	$ -
2018	$ 63,943	$ 62,761	$ 25,351	$ -	$ -	$ -	$ 8,477	$ -	$ -
2019	$ 67,318	$ 66,135	$ 26,397	$ -	$ -	$ -	$ 8,852	$ -	$ -
2020	$ 70,692	$ 69,510	$ 27,443	$ -	$ -	$ -	$ 9,227	$ -	$ -
2021	$ 74,194	$ 73,011	$ 28,528	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 77,826	$ 76,644	$ 29,654	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 81,596	$ 80,413	$ 30,822	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 85,506	$ 84,323	$ 32,034	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 88,381	$ 33,292	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 92,591	$ 34,596	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 96,959	$ 35,950	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 101,491	$ 37,355	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 106,194	$ 38,812	$ -	$ -	$ -	$ -	$ -	$ -

*** If contribution margin is negative then plant does not operate, but incurs taxes and decommissioning costs.*

**** Shaded areas indicate plant does not operate.*

Operating Assumptions

Data Inputs											
Plant Name		Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Capacity (MW)		9,029	332	512	345		250	1,341			340
Case Description:		EDS - Utilizing J. Bustard's Market Revenue Estimates									
Plant Type			Coal	Water	Coal	Gas	Oil	Coal	Coal	Gas	Coal
Decommissioning:											
Decommissioning Year - Adjusted			2021	2029	2004	1999	1999	2010	2025	2010	2018
Decommissioning Year - Nameplate			2006	2014	2004	1999	1999	2010	2010	2010	2003
Life Extension Years			15	15	0	0	0	0	15	0	15
Required Life Extension Costs	1997	$ 251,000	$ 75,000	$ 10,000	$ -	$ -	$ -	$ -	$ 51,000	$ -	$ 75,000
Decommissioning Exp.	Flat	$ 31,344	$ 1,280	$ -	$ 366	$ 522	$ -	$ 710	$ 768	$ 2,762	$ 1,298
O&M Buildup:											
Fixed Charge - $000	1997	$ 444,432	$ 7,677	$ 8,950	$ 6,762	$ 3,842	$ 4,789	$ 11,582	$ 9,528	$ 9,093	$ 6,811
Incremental Charge - $/MWhr	1997		$ -	$ 0.69	$ 3.38	$ 0.51	$ 1.68	$ 4.07	$ 3.24	$ 0.48	$ -
NOX 1999-2002 $/MWhr	1997		$ -	$ -	$ 1.09	$ 1.43	$ 0.20	$ 0.64	$ 1.69	$ 0.79	$ -
NOX 2003&Thereafter $/MWhr	1997		$ -	$ -	$ 2.52	$ 3.10	$ 0.76	$ 1.06	$ 2.34	$ 1.81	$ -
Merrill Creek	Flat	$ 16,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1997 Operating & Maintenance - Base		$ 477,647	$ 7,677	$ 10,172	$ 9,812	$ 3,842	$ 4,789	$ 18,178	$ 15,176	$ 9,093	$ 6,811
1996 Operating & Maintenance -Estimate		$ 493,881	$ -	$ 8,555	$ 8,659	$ 5,146	$ 5,220	$ 17,706	$ 13,982	$ 8,342	$ -
1995 Operating & Maintenance - Actual		$ 486,254	$ 10,758	$ 8,018	$ 8,849	$ 7,398	$ 7,736	$ 23,358	$ 16,841	$ 6,915	$ 9,685
1994 Operating & Maintenance - Actual		$ 507,353	$ 11,395	$ 9,942	$ 14,466	$ 5,540	$ 7,742	$ 25,813	$ 21,560	$ 19,702	$ 10,933
Capital Expenditures:											
1997 Capital Expenditures Base		93,960	$ 1,960	$ 1,400	$ 1,500	$ 900	$ 1,600	$ 1,800	$ 1,800	$ 1,800	$ 2,760
1996 Capital Expenditures Estimate		203,205	$ 5,196	$ 13,306	$ 140	$ 1,654	$ 100	$ 1,154	$ 1,124	$ 890	$ 3,761
1995 Capital Expenditures Actual		169,267	$ 8,751	$ 5,958	$ 429	$ 3,334	$ 154	$ 8,415	$ 5,141	$ 3,573	$ 7,275
1994 Capital Expenditures Actual		158,081	$ -	$ 943	$ 10,217	$ 827	$ 1,617	$ 5,895	$ 4,393	$ 13,223	$ -
Other Costs:											
Admin & General Exp.	1995	$ 58,728	$ -	$ 1,774	$ 1,711	$ 670	$ 835	$ 3,170	$ 2,647	$ 1,586	$ -
Other Taxes	1995	$ 104,936	$ -	$ 3,169	$ 3,057	$ 1,197	$ 1,492	$ 5,664	$ 4,729	$ 2,833	$ -
Allocation Factors:											
1997 O&M ex Salem,Keystone&Conemaugh		336,771	$ -	$ 10,172	$ 9,812	$ 3,842	$ 4,789	$ 18,178	$ 15,176	$ 9,093	$ -
			0.0%	*3.0%*	*2.9%*	*1.1%*	*1.4%*	*5.4%*	*4.5%*	*2.7%*	*0.0%*

Operating Assumptions

Data Inputs																					
Plant Name			Limerick 1		Limerick 2		Muddy Run		P. Bottom 2		P. Bottom 3		Salem 1		Salem 2		Schuylkill		C. Turbines	
Capacity (MW)			2,170				880		929				942				166		822	
Case Description:																				
Plant Type			Nuc		Nuc		Water		Nuc		Nuc		Nuc		Nuc		Oil		Oil	
Decommissioning:																				
Decommissioning Year - Adjusted			2024		2029		2029		2013		2014		2016		2020		1999		2014	
Decommissioning Year - Nameplate			2024		2029		2014		2013		2014		2016		2020		1999		1999	
Life Extension Years			0		0		15		0		0		0		0		0		15	
Required Life Extension Costs	1997	$	-	$	-	$	20,000	$	-	$	-	$	-	$	-	$	-	$	20,000
Decommissioning Exp.	Flat	$	3,116	$	5,138	$	-	$	5,413	$	5,407	$	2,626	$	1,939	$	-	$	-
O&M Buildup:																				
Fixed Charge - $000	1997	$	79,053	$	79,053	$	7,639	$	35,711	$	35,711	$	63,194	$	63,194	$	2,713	$	9,131
Incremental Charge - $/MWhr	1997	$	-	$	-	$	0.45	$	-	$	-	$	-	$	-	$	0.43	$	2.22
NOX 1999-2002 $/MWhr	1997	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	1,080
NOX 2003&Thereafter $/MWhr	1997	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	0.31	$	1,960
Merrill Creek	Flat	$	8,200	$	8,200	$	-	$	-	$	-	$	-	$	-	$	-	$	-
1997 Operating & Maintenance - Base		$	87,253	$	87,253	$	7,938	$	35,711	$	35,711	$	63,194	$	63,194	$	2,713	$	9,131
1996 Operating & Maintenance -Estimate		$	96,815	$	68,700	$	6,164	$	46,458	$	23,357	$	84,490	$	93,287	$	7,000	$	-
1995 Operating & Maintenance - Actual		$	76,315	$	91,630	$	4,708	$	28,435	$	47,823	$	73,035	$	58,183	$	2,910	$	3,657
1994 Operating & Maintenance - Actual		$	98,434	$	74,749	$	4,870	$	53,885	$	25,631	$	60,924	$	55,692	$	6,075	$	-
Capital Expenditures:			**		**															
1997 Capital Expenditures Base		$	22,736	$	22,736	$	1,100	$	7,542	$	7,542	$	7,542	$	7,542	$	800	$	900
1996 Capital Expenditures Estimate		$	19,119	$	7,707	$	12,067	$	8,108	$	5,130	$	75,015	$	47,698	$	47	$	989
1995 Capital Expenditures Actual		$	16,445	$	23,350	$	3,930	$	9,449	$	12,511	$	30,773	$	29,433	$	84	$	262
1994 Capital Expenditures Actual		$	22,183	$	23,474	$	3,830	$	23,061	$	5,891	$	20,218	$	20,800	$	1,509	$	-
		** includes Carrying Charges on Limerick fuel inventory																		
Other Costs:																				
Admin & General Exp.	1995	$	15,216	$	15,216	$	1,384	$	6,227	$	6,227	$	-	$	-	$	473	$	1,592
Other Taxes	1995	$	27,188	$	27,188	$	2,473	$	11,127	$	11,127	$	-	$	-	$	845	$	2,845
Allocation Factors:																				
1997 O&M ex Salem,Keystone&Conemaugh		$	87,253	$	87,253	$	7,938	$	35,711	$	35,711	$	-	$	-	$	2,713	$	9,131
			25.9%		*25.9%*		*2.4%*		*10.6%*		*10.6%*		*0.0%*		*0.0%*		*0.8%*		*2.7%*	

General Assumption	
Discount Rate	8.88%
Income Tax Rate	41.493%

Growth Assumptions		
Year	Annual GDP Deflator	Cumulative GDP Deflator
1995	Base	Base
1996	1.0200	1.0200
1997	1.0196	1.0400
1998	1.0288	1.0700
1999	1.0187	1.0900
2000	1.0275	1.1200
2001	1.0268	1.1500
2002	1.0348	1.1900
2003	1.0252	1.2200
2004	1.0328	1.2600
2005	1.0317	1.3000
2006	1.0385	1.3500
2007	1.0296	1.3900
2008	1.0360	1.4400
2009	1.0347	1.4900
2010	1.0403	1.5500
2011	1.0323	1.6000
2012	1.0375	1.6600
2013	1.0361	1.7200
2014	1.0349	1.7800
2015	1.0337	1.8400
2016	1.0380	1.9100
2017	1.0366	1.9800
2018	1.0354	2.0500
2019	1.0390	2.1300
2020	1.0376	2.2100
2021	1.0376	2.2930
2022	1.0376	2.3791
2023	1.0376	2.4685
2024	1.0376	2.5612
2025	1.0376	2.6574
2026	1.0376	2.7572
2027	1.0376	2.8608
2028	1.0376	2.9682
2029	1.0376	3.0797

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Generation Projection (MWhrs)						(1)			(1)	
1999	39,968,114	2,755,279	1,771,000	928,560	17,520	1	1,664,400	1,795,800	1	2,666,150
2000	40,177,009	2,744,389	1,771,000	937,320	-	-	1,681,920	1,813,320	1	2,677,182
2001	40,296,153	2,744,389	1,771,000	946,080	-	-	1,708,200	1,839,600	1	2,702,924
2002	40,496,217	2,773,430	1,771,000	954,840	-	-	1,734,480	1,874,640	1	2,717,634
2003	40,692,113	2,784,320	1,771,000	972,360	-	-	1,769,520	1,909,680	1	2,750,731
2004	40,839,913	2,784,320	1,771,000	989,880	-	-	1,804,560	1,944,720	1	2,754,409
2005	39,960,178	2,784,320	1,771,000	-	-	-	1,830,840	1,971,000	1	2,776,473
2006	39,687,224	2,780,690	1,771,000	-	-	-	1,822,080	1,971,000	1	2,758,086
2007	39,346,884	2,733,498	1,771,000	-	-	-	1,822,080	1,971,000	1	2,721,312
2008	39,461,799	2,733,498	1,771,000	-	-	-	1,848,360	1,988,520	1	2,724,989
2009	39,440,781	2,733,498	1,771,000	-	-	-	1,857,120	1,997,280	1	2,717,634
2010	39,384,381	2,740,759	1,771,000	-	-	-	1,874,640	2,014,800	1	2,739,699
2011	37,509,740	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2012	37,509,740	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2013	37,509,740	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2014	34,431,544	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2015	31,353,346	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2016	31,353,346	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2017	28,256,712	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2018	28,256,712	2,740,759	1,771,000	-	-	-	-	2,014,800	-	2,739,699
2019	25,517,014	2,740,759	1,771,000	-	-	-	-	2,014,800	-	-
2020	25,517,014	2,740,759	1,771,000	-	-	-	-	2,014,800	-	-
2021	22,420,380	2,740,759	1,771,000	-	-	-	-	2,014,800	-	-
2022	19,679,621	-	1,771,000	-	-	-	-	2,014,800	-	-
2023	19,679,621	-	1,771,000	-	-	-	-	2,014,800	-	-
2024	19,679,621	-	1,771,000	-	-	-	-	2,014,800	-	-
2025	12,417,581	-	1,771,000	-	-	-	-	2,014,800	-	-
2026	10,402,781	-	1,771,000	-	-	-	-	-	-	-
2027	10,402,781	-	1,771,000	-	-	-	-	-	-	-
2028	10,402,781	-	1,771,000	-	-	-	-	-	-	-
2029	10,402,781	-	1,771,000	-	-	-	-	-	-	-

(1) *indicates capacity payment*

EDS - Utilizing J. Bustard's Market Revenue

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Generation Projection (MWhrs)								(1)	(1)
1999	7,262,040	7,262,040	1,495,660	3,078,197	3,078,197	3,096,634	3,096,634	1	1
2000	7,262,040	7,262,040	1,678,135	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2001	7,262,040	7,262,040	1,710,217	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2002	7,262,040	7,262,040	1,796,451	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2003	7,262,040	7,262,040	1,860,759	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2004	7,262,040	7,262,040	1,917,282	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2005	7,262,040	7,262,040	1,952,801	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2006	7,262,040	7,262,040	1,718,087	3,078,197	3,078,197	3,092,903	3,092,903	-	1
2007	7,262,040	7,262,040	1,461,713	3,078,197	3,078,197	3,092,903	3,092,903	-	1
2008	7,262,040	7,262,040	1,521,689	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2009	7,262,040	7,262,040	1,497,968	3,078,197	3,078,197	3,092,903	3,092,903	-	1
2010	7,262,040	7,262,040	1,369,741	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2011	7,262,040	7,262,040	1,369,741	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2012	7,262,040	7,262,040	1,369,741	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2013	7,262,040	7,262,040	1,369,741	3,078,197	3,078,197	3,096,634	3,096,634	-	1
2014	7,262,040	7,262,040	1,369,741	-	3,078,197	3,096,634	3,096,634	-	1
2015	7,262,040	7,262,040	1,369,741	-	-	3,096,634	3,096,634	-	-
2016	7,262,040	7,262,040	1,369,741	-	-	3,096,634	3,096,634	-	-
2017	7,262,040	7,262,040	1,369,741	-	-	-	3,096,634	-	-
2018	7,262,040	7,262,040	1,369,741	-	-	-	3,096,634	-	-
2019	7,262,040	7,262,040	1,369,741	-	-	-	3,096,634	-	-
2020	7,262,040	7,262,040	1,369,741	-	-	-	3,096,634	-	-
2021	7,262,040	7,262,040	1,369,741	-	-	-	-	-	-
2022	7,262,040	7,262,040	1,369,741	-	-	-	-	-	-
2023	7,262,040	7,262,040	1,369,741	-	-	-	-	-	-
2024	7,262,040	7,262,040	1,369,741	-	-	-	-	-	-
2025	-	7,262,040	1,369,741	-	-	-	-	-	-
2026	-	7,262,040	1,369,741	-	-	-	-	-	-
2027	-	7,262,040	1,369,741	-	-	-	-	-	-
2028	-	7,262,040	1,369,741	-	-	-	-	-	-
2029	-	7,262,040	1,369,741	-	-	-	-	-	-

(1) indicates capacity payment

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Market Price Rate ($/MWhr)										
Energy & Capacity						(1)			(1)	
1999	$ 29.16	$ 25.89	$ 34.63	$ 28.00	$ 403.81	##########	$ 28.82	$ 28.81	##########	$ 26.40
2000	$ 31.24	$ 27.93	$ 38.16	$ 30.25	$ -	$ -	$ 31.20	$ 31.22	##########	$ 28.44
2001	$ 32.58	$ 29.24	$ 40.58	$ 31.56	$ -	$ -	$ 32.47	$ 32.53	##########	$ 29.67
2002	$ 34.13	$ 30.64	$ 42.47	$ 33.10	$ -	$ -	$ 34.04	$ 33.97	##########	$ 31.14
2003	$ 35.85	$ 32.22	$ 45.47	$ 34.53	$ -	$ -	$ 35.56	$ 35.54	##########	$ 32.65
2004	$ 37.73	$ 34.04	$ 48.48	$ 36.20	$ -	$ -	$ 37.27	$ 37.35	##########	$ 34.45
2005	$ 39.99	$ 36.04	$ 51.42	$ -	$ -	$ -	$ 39.38	$ 39.45	##########	$ 36.39
2006	$ 41.08	$ 37.12	$ 54.36	$ -	$ -	$ -	$ 40.61	$ 40.49	##########	$ 37.54
2007	$ 43.20	$ 39.16	$ 59.69	$ -	$ -	$ -	$ 42.57	$ 42.44	##########	$ 39.56
2008	$ 44.03	$ 40.33	$ 59.07	$ -	$ -	$ -	$ 43.44	$ 43.54	##########	$ 40.67
2009	$ 45.18	$ 41.54	$ 61.49	$ -	$ -	$ -	$ 44.57	$ 44.69	##########	$ 41.90
2010	$ 46.67	$ 42.66	$ 67.77	$ -	$ -	$ -	$ 45.68	$ 45.83	##########	$ 42.98
2011	$ 48.09	$ 44.56	$ 70.78	$ -	$ -	$ -	$ -	$ 47.87	$ -	$ 44.88
2012	$ 50.22	$ 46.53	$ 73.92	$ -	$ -	$ -	$ -	$ 49.99	$ -	$ 46.88
2013	$ 52.45	$ 48.60	$ 77.20	$ -	$ -	$ -	$ -	$ 52.21	$ -	$ 48.96
2014	$ 55.08	$ 50.76	$ 80.63	$ -	$ -	$ -	$ -	$ 54.53	$ -	$ 51.13
2015	$ 56.84	$ 53.01	$ 84.20	$ -	$ -	$ -	$ -	$ 56.95	$ -	$ 53.40
2016	$ 59.00	$ 55.02	$ 87.41	$ -	$ -	$ -	$ -	$ 59.11	$ -	$ 55.43
2017	$ 61.54	$ 57.04	$ 90.61	$ -	$ -	$ -	$ -	$ 61.28	$ -	$ 57.46
2018	$ 63.71	$ 59.06	$ 93.82	$ -	$ -	$ -	$ -	$ 63.44	$ -	$ 59.49
2019	$ 66.67	$ 61.36	$ 97.48	$ -	$ -	$ -	$ -	$ 65.92	$ -	$ -
2020	$ 69.18	$ 63.67	$ 101.14	$ -	$ -	$ -	$ -	$ 68.40	$ -	$ -
2021	$ 72.46	$ 66.06	$ 104.94	$ -	$ -	$ -	$ -	$ 70.96	$ -	$ -
2022	$ 76.10	$ -	$ 108.88	$ -	$ -	$ -	$ -	$ 73.63	$ -	$ -
2023	$ 78.96	$ -	$ 112.97	$ -	$ -	$ -	$ -	$ 76.40	$ -	$ -
2024	$ 81.93	$ -	$ 117.21	$ -	$ -	$ -	$ -	$ 79.26	$ -	$ -
2025	$ 89.41	$ -	$ 121.61	$ -	$ -	$ -	$ -	$ 82.24	$ -	$ -
2026	$ 94.21	$ -	$ 126.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 97.75	$ -	$ 130.92	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 101.42	$ -	$ 135.84	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 105.23	$ -	$ 140.94	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(1) ### indicates capacity payment not rate

EDS - Utilizing J. Bustard's Market Revenue
(000)

Market Price Rate ($/MWhr)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Energy & Capacity								(1)	(1)
1999	$ 26.58	$ 26.58	$ 34.63	$ 26.60	$ 26.60	$ 26.57	$ 26.57	##########	##########
2000	$ 28.77	$ 28.77	$ 38.16	$ 28.78	$ 28.78	$ 28.76	$ 28.76	$ -	##########
2001	$ 30.00	$ 30.00	$ 40.58	$ 30.02	$ 30.02	$ 29.99	$ 29.99	$ -	##########
2002	$ 31.46	$ 31.46	$ 42.47	$ 31.48	$ 31.48	$ 31.45	$ 31.45	$ -	##########
2003	$ 33.04	$ 33.04	$ 45.47	$ 33.06	$ 33.06	$ 33.03	$ 33.03	$ -	##########
2004	$ 34.83	$ 34.83	$ 48.48	$ 34.85	$ 34.85	$ 34.82	$ 34.82	$ -	##########
2005	$ 36.85	$ 36.85	$ 51.42	$ 36.87	$ 36.87	$ 36.84	$ 36.84	$ -	##########
2006	$ 37.89	$ 37.89	$ 54.36	$ 37.91	$ 37.91	$ 37.93	$ 37.93	$ -	##########
2007	$ 39.82	$ 39.82	$ 59.69	$ 39.84	$ 39.84	$ 39.86	$ 39.86	$ -	##########
2008	$ 40.87	$ 40.87	$ 59.07	$ 40.89	$ 40.89	$ 40.86	$ 40.86	$ -	##########
2009	$ 42.01	$ 42.01	$ 61.49	$ 42.03	$ 42.03	$ 42.05	$ 42.05	$ -	##########
2010	$ 43.18	$ 43.18	$ 67.77	$ 43.20	$ 43.20	$ 43.16	$ 43.16	$ -	##########
2011	$ 45.09	$ 45.09	$ 70.78	$ 45.12	$ 45.12	$ 45.08	$ 45.08	$ -	##########
2012	$ 47.09	$ 47.09	$ 73.92	$ 47.12	$ 47.12	$ 47.08	$ 47.08	$ -	##########
2013	$ 49.18	$ 49.18	$ 77.20	$ 49.21	$ 49.21	$ 49.17	$ 49.17	$ -	##########
2014	$ 51.36	$ 51.36	$ 80.63	$ -	$ 51.39	$ 51.35	$ 51.35	$ -	##########
2015	$ 53.64	$ 53.64	$ 84.20	$ -	$ -	$ 53.63	$ 53.63	$ -	$ -
2016	$ 55.68	$ 55.68	$ 87.41	$ -	$ -	$ 55.67	$ 55.67	$ -	$ -
2017	$ 57.72	$ 57.72	$ 90.61	$ -	$ -	$ -	$ 57.71	$ -	$ -
2018	$ 59.76	$ 59.76	$ 93.82	$ -	$ -	$ -	$ 59.75	$ -	$ -
2019	$ 62.10	$ 62.10	$ 97.48	$ -	$ -	$ -	$ 62.08	$ -	$ -
2020	$ 64.43	$ 64.43	$ 101.14	$ -	$ -	$ -	$ 64.41	$ -	$ -
2021	$ 66.85	$ 66.85	$ 104.94	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 69.36	$ 69.36	$ 108.88	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 71.96	$ 71.96	$ 112.97	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 74.67	$ 74.67	$ 117.21	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 77.47	$ 121.61	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 80.38	$ 126.18	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 83.40	$ 130.92	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 86.53	$ 135.84	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 89.78	$ 140.94	$ -	$ -	$ -	$ -	$ -	$ -

(1) ### indicates capacity payment not rate

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Market Price Revenues	*(generation x market rate) (000's)*									
Energy & Capacity										
1999	$ 1,165,383	$ 71,329	$ 61,337	$ 26,000	$ 7,075	$ 7,974	$ 47,969	$ 51,737	$ 24,240	$ 70,386
2000	$ 1,255,142	$ 76,663	$ 67,583	$ 28,354	$ -	$ -	$ 52,468	$ 56,604	$ 29,135	$ 76,129
2001	$ 1,312,872	$ 80,257	$ 71,872	$ 29,862	$ -	$ -	$ 55,468	$ 59,839	$ 28,842	$ 80,205
2002	$ 1,382,218	$ 84,985	$ 75,217	$ 31,605	$ -	$ -	$ 59,038	$ 63,688	$ 29,575	$ 84,638
2003	$ *1,458,726*	$ *89,711*	$ *80,536*	$ *33,579*	$ -	$ -	$ *62,925*	$ *67,878*	$ *29,858*	$ *89,812*
2004	$ 1,541,021	$ 94,778	$ 85,861	$ 35,836	$ -	$ -	$ 67,249	$ 72,629	$ 29,402	$ 94,887
2005	$ 1,597,830	$ 100,336	$ 91,072	$ -	$ -	$ -	$ 72,090	$ 77,759	$ 31,306	$ 101,026
2006	$ 1,630,346	$ 103,217	$ 96,272	$ -	$ -	$ -	$ 73,994	$ 79,809	$ 29,896	$ 103,545
2007	$ 1,699,684	$ 107,045	$ 105,705	$ -	$ -	$ -	$ 77,564	$ 83,657	$ 29,349	$ 107,649
2008	$ 1,737,368	$ 110,249	$ 104,617	$ -	$ -	$ -	$ 80,285	$ 86,586	$ 27,373	$ 110,825
2009	$ 1,782,057	$ 113,543	$ 108,903	$ -	$ -	$ -	$ 82,775	$ 89,267	$ 25,432	$ 113,878
2010	$ 1,838,067	$ 116,933	$ 120,029	$ -	$ -	$ -	$ 85,632	$ 92,346	$ 25,257	$ 117,745
2011	$ 1,803,812	$ 122,121	$ 125,355	$ -	$ -	$ -	$ -	$ 96,443	$ -	$ 122,969
2012	$ 1,883,846	$ 127,539	$ 130,916	$ -	$ -	$ -	$ -	$ 100,722	$ -	$ 128,425
2013	$ 1,967,430	$ 133,198	$ 136,725	$ -	$ -	$ -	$ -	$ 105,191	$ -	$ 134,123
2014	$ 1,896,533	$ 139,108	$ 142,791	$ -	$ -	$ -	$ -	$ 109,859	$ -	$ 140,074
2015	$ 1,781,986	$ 145,280	$ 149,127	$ -	$ -	$ -	$ -	$ 114,733	$ -	$ 146,289
2016	$ 1,849,779	$ 150,807	$ 154,800	$ -	$ -	$ -	$ -	$ 119,098	$ -	$ 151,854
2017	$ 1,738,877	$ 156,334	$ 160,474	$ -	$ -	$ -	$ -	$ 123,463	$ -	$ 157,419
2018	$ 1,800,353	$ 161,861	$ 166,147	$ -	$ -	$ -	$ -	$ 127,827	$ -	$ 162,985
2019	$ 1,701,265	$ 168,178	$ 172,631	$ -	$ -	$ -	$ -	$ 132,816	$ -	$ -
2020	$ 1,765,163	$ 174,494	$ 179,114	$ -	$ -	$ -	$ -	$ 137,804	$ -	$ -
2021	$ 1,624,517	$ 181,048	$ 185,842	$ -	$ -	$ -	$ -	$ 142,980	$ -	$ -
2022	$ 1,497,684	$ -	$ 192,822	$ -	$ -	$ -	$ -	$ 148,350	$ -	$ -
2023	$ 1,553,935	$ -	$ 200,064	$ -	$ -	$ -	$ -	$ 153,922	$ -	$ -
2024	$ 1,612,299	$ -	$ 207,578	$ -	$ -	$ -	$ -	$ 159,703	$ -	$ -
2025	$ 1,110,253	$ -	$ 215,374	$ -	$ -	$ -	$ -	$ 165,701	$ -	$ -
2026	$ 980,028	$ -	$ 223,463	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 1,016,837	$ -	$ 231,856	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 1,055,028	$ -	$ 240,565	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 1,094,653	$ -	$ 249,600	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Market Price Revenues									
Energy & Capacity									
1999	$ 193,033	$ 193,033	$ 51,801	$ 81,866	$ 81,866	$ 82,287	$ 82,287	$ 5,295	$ 25,867
2000	$ 208,896	$ 208,896	$ 64,039	$ 88,594	$ 88,594	$ 89,049	$ 89,049	$ -	$ 31,090
2001	$ 217,885	$ 217,885	$ 69,405	$ 92,406	$ 92,406	$ 92,881	$ 92,881	$ -	$ 30,777
2002	$ 228,496	$ 228,496	$ 76,298	$ 96,906	$ 96,906	$ 97,404	$ 97,404	$ -	$ 31,560
2003	$ 239,936	$ 239,936	$ 84,618	$ 101,758	$ 101,758	$ 102,281	$ 102,281	$ -	$ 31,861
2004	$ 252,933	$ 252,933	$ 92,953	$ 107,270	$ 107,270	$ 107,822	$ 107,822	$ -	$ 31,375
2005	$ 267,623	$ 267,623	$ 100,421	$ 113,500	$ 113,500	$ 114,084	$ 114,084	$ -	$ 33,406
2006	$ 275,163	$ 275,163	$ 93,396	$ 116,696	$ 116,696	$ 117,298	$ 117,298	$ -	$ 31,902
2007	$ 289,170	$ 289,170	$ 87,245	$ 122,637	$ 122,637	$ 123,269	$ 123,269	$ -	$ 31,318
2008	$ 296,786	$ 296,786	$ 89,890	$ 125,866	$ 125,866	$ 126,516	$ 126,516	$ -	$ 29,210
2009	$ 305,074	$ 305,074	$ 92,114	$ 129,381	$ 129,381	$ 130,049	$ 130,049	$ -	$ 27,138
2010	$ 313,540	$ 313,540	$ 92,834	$ 132,973	$ 132,973	$ 133,658	$ 133,658	$ -	$ 26,952
2011	$ 327,451	$ 327,451	$ 96,953	$ 138,873	$ 138,873	$ 139,588	$ 139,588	$ -	$ 28,147
2012	$ 341,980	$ 341,980	$ 101,254	$ 145,035	$ 145,035	$ 145,781	$ 145,781	$ -	$ 29,396
2013	$ 357,154	$ 357,154	$ 105,747	$ 151,470	$ 151,470	$ 152,249	$ 152,249	$ -	$ 30,701
2014	$ 373,000	$ 373,000	$ 110,439	$ -	$ 158,190	$ 159,004	$ 159,004	$ -	$ 32,063
2015	$ 389,550	$ 389,550	$ 115,339	$ -	$ -	$ 166,059	$ 166,059	$ -	$ -
2016	$ 404,370	$ 404,370	$ 119,727	$ -	$ -	$ 172,377	$ 172,377	$ -	$ -
2017	$ 419,189	$ 419,189	$ 124,115	$ -	$ -	$ -	$ 178,694	$ -	$ -
2018	$ 434,009	$ 434,009	$ 128,503	$ -	$ -	$ -	$ 185,012	$ -	$ -
2019	$ 450,946	$ 450,946	$ 133,517	$ -	$ -	$ -	$ 192,232	$ -	$ -
2020	$ 467,883	$ 467,883	$ 138,532	$ -	$ -	$ -	$ 199,452	$ -	$ -
2021	$ 485,456	$ 485,456	$ 143,735	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 503,689	$ 503,689	$ 149,134	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 522,607	$ 522,607	$ 154,735	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 542,236	$ 542,236	$ 160,547	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 562,601	$ 166,577	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 583,732	$ 172,833	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 605,656	$ 179,324	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 628,404	$ 186,059	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 652,006	$ 193,048	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)

Fuel Rate ($/MWhr)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
1999	$ 7.72	$ 11.18	$ -	$ 16.51	$ 35.84	$ -	$ 17.46	$ 17.44	$ -	$ 14.46
2000	$ 7.90	$ 11.50	$ -	$ 17.02	$ -	$ -	$ 18.00	$ 18.00	$ -	$ 14.88
2001	$ 8.02	$ 11.71	$ -	$ 17.28	$ -	$ -	$ 18.24	$ 18.26	$ -	$ 15.13
2002	$ 8.20	$ 11.88	$ -	$ 17.53	$ -	$ -	$ 18.51	$ 18.46	$ -	$ 15.37
2003	$ 8.44	$ 12.17	$ -	$ 17.86	$ -	$ -	$ 18.89	$ 18.86	$ -	$ 15.73
2004	$ 8.65	$ 12.36	$ -	$ 18.07	$ -	$ -	$ 19.10	$ 19.14	$ -	$ 15.96
2005	$ 8.63	$ 12.51	$ -	$ -	$ -	$ -	$ 19.33	$ 19.35	$ -	$ 16.14
2006	$ 8.83	$ 12.87	$ -	$ -	$ -	$ -	$ 19.92	$ 19.85	$ -	$ 16.63
2007	$ 9.05	$ 13.26	$ -	$ -	$ -	$ -	$ 20.48	$ 20.41	$ -	$ 17.12
2008	$ 9.35	$ 13.67	$ -	$ -	$ -	$ -	$ 21.01	$ 21.05	$ -	$ 17.62
2009	$ 9.66	$ 14.08	$ -	$ -	$ -	$ -	$ 21.64	$ 21.69	$ -	$ 18.16
2010	$ 10.01	$ 14.49	$ -	$ -	$ -	$ -	$ 22.26	$ 22.32	$ -	$ 18.69
2011	$ 9.71	$ 14.99	$ -	$ -	$ -	$ -	$ -	$ 23.11	$ -	$ 19.34
2012	$ 10.06	$ 15.52	$ -	$ -	$ -	$ -	$ -	$ 23.91	$ -	$ 20.02
2013	$ 10.42	$ 16.06	$ -	$ -	$ -	$ -	$ -	$ 24.75	$ -	$ 20.72
2014	$ 11.02	$ 16.62	$ -	$ -	$ -	$ -	$ -	$ 25.62	$ -	$ 21.45
2015	$ 11.69	$ 17.20	$ -	$ -	$ -	$ -	$ -	$ 26.51	$ -	$ 22.20
2016	$ 12.13	$ 17.86	$ -	$ -	$ -	$ -	$ -	$ 27.52	$ -	$ 23.04
2017	$ 12.96	$ 18.51	$ -	$ -	$ -	$ -	$ -	$ 28.53	$ -	$ 23.89
2018	$ 13.42	$ 19.17	$ -	$ -	$ -	$ -	$ -	$ 29.54	$ -	$ 24.73
2019	$ 12.68	$ 19.92	$ -	$ -	$ -	$ -	$ -	$ 30.69	$ -	$ -
2020	$ 13.16	$ 20.66	$ -	$ -	$ -	$ -	$ -	$ 31.85	$ -	$ -
2021	$ 14.08	$ 21.44	$ -	$ -	$ -	$ -	$ -	$ 33.04	$ -	$ -
2022	$ 13.55	$ -	$ -	$ -	$ -	$ -	$ -	$ 34.28	$ -	$ -
2023	$ 14.05	$ -	$ -	$ -	$ -	$ -	$ -	$ 35.57	$ -	$ -
2024	$ 14.58	$ -	$ -	$ -	$ -	$ -	$ -	$ 36.91	$ -	$ -
2025	$ 18.30	$ -	$ -	$ -	$ -	$ -	$ -	$ 38.29	$ -	$ -
2026	$ 14.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 15.53	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 16.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 16.72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue
(000)

Fuel Rate ($/MWhr)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
1999	$ 4.46	$ 4.46	$ 17.32	$ 5.84	$ 5.84	$ 5.84	$ 5.84	$ -	$ -
2000	$ 4.42	$ 4.42	$ 19.08	$ 5.74	$ 5.74	$ 5.74	$ 5.74	$ -	$ -
2001	$ 4.43	$ 4.43	$ 20.29	$ 5.68	$ 5.68	$ 5.68	$ 5.68	$ -	$ -
2002	$ 4.50	$ 4.50	$ 21.24	$ 5.72	$ 5.72	$ 5.72	$ 5.72	$ -	$ -
2003	$ 4.55	$ 4.55	$ 22.74	$ 5.75	$ 5.75	$ 5.75	$ 5.75	$ -	$ -
2004	$ 4.60	$ 4.60	$ 24.24	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ -	$ -
2005	$ 4.68	$ 4.68	$ 25.71	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ -	$ -
2006	$ 4.87	$ 4.87	$ 27.18	$ 6.17	$ 6.17	$ 6.17	$ 6.17	$ -	$ -
2007	$ 5.06	$ 5.06	$ 29.84	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ -	$ -
2008	$ 5.26	$ 5.26	$ 29.54	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ -	$ -
2009	$ 5.44	$ 5.44	$ 30.75	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ -	$ -
2010	$ 5.66	$ 5.66	$ 33.89	$ 7.12	$ 7.12	$ 7.12	$ 7.12	$ -	$ -
2011	$ 5.84	$ 5.84	$ 35.07	$ 7.35	$ 7.35	$ 7.35	$ 7.35	$ -	$ -
2012	$ 6.06	$ 6.06	$ 36.30	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ -	$ -
2013	$ 6.28	$ 6.28	$ 37.57	$ 7.90	$ 7.90	$ 7.90	$ 7.90	$ -	$ -
2014	$ 6.50	$ 6.50	$ 38.89	$ -	$ 8.17	$ 8.17	$ 8.17	$ -	$ -
2015	$ 6.72	$ 6.72	$ 40.25	$ -	$ -	$ 8.45	$ 8.45	$ -	$ -
2016	$ 6.98	$ 6.98	$ 41.78	$ -	$ -	$ 8.77	$ 8.77	$ -	$ -
2017	$ 7.23	$ 7.23	$ 43.31	$ -	$ -	$ -	$ 9.09	$ -	$ -
2018	$ 7.49	$ 7.49	$ 44.84	$ -	$ -	$ -	$ 9.41	$ -	$ -
2019	$ 7.78	$ 7.78	$ 46.59	$ -	$ -	$ -	$ 9.78	$ -	$ -
2020	$ 8.07	$ 8.07	$ 48.34	$ -	$ -	$ -	$ 10.15	$ -	$ -
2021	$ 8.38	$ 8.38	$ 50.16	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 8.69	$ 8.69	$ 52.04	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 9.02	$ 9.02	$ 53.99	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 9.36	$ 9.36	$ 56.02	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 9.71	$ 58.13	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 10.07	$ 60.31	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 10.45	$ 62.58	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 10.84	$ 64.93	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 11.25	$ 67.36	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Fuel Cost	*(generation x fuel rate) (000's)*									
1999	$ 308,379	$ 30,792	$ -	$ 15,331	$ 628	$ -	$ 29,058	$ 31,315	$ -	$ 38,561
2000	$ 317,340	$ 31,570	$ -	$ 15,952	$ -	$ -	$ 30,273	$ 32,632	$ -	$ 39,849
2001	$ 323,304	$ 32,141	$ -	$ 16,350	$ -	$ -	$ 31,155	$ 33,583	$ -	$ 40,902
2002	$ 332,236	$ 32,955	$ -	$ 16,739	$ -	$ -	$ 32,100	$ 34,601	$ -	$ 41,758
2003	$ 343,398	$ 33,891	$ -	$ 17,364	$ -	$ -	$ 33,420	$ 36,024	$ -	$ 43,258
2004	$ 353,273	$ 34,421	$ -	$ 17,886	$ -	$ -	$ 34,466	$ 37,213	$ -	$ 43,964
2005	$ 344,889	$ 34,825	$ -	$ -	$ -	$ -	$ 35,390	$ 38,148	$ -	$ 44,826
2006	$ 350,596	$ 35,788	$ -	$ -	$ -	$ -	$ 36,300	$ 39,128	$ -	$ 45,860
2007	$ 356,269	$ 36,241	$ -	$ -	$ -	$ -	$ 37,317	$ 40,225	$ -	$ 46,593
2008	$ 369,080	$ 37,359	$ -	$ -	$ -	$ -	$ 38,833	$ 41,859	$ -	$ 48,019
2009	$ 380,908	$ 38,483	$ -	$ -	$ -	$ -	$ 40,185	$ 43,317	$ -	$ 49,364
2010	$ 394,168	$ 39,702	$ -	$ -	$ -	$ -	$ 41,727	$ 44,979	$ -	$ 51,204
2011	$ 364,310	$ 41,092	$ -	$ -	$ -	$ -	$ -	$ 46,553	$ -	$ 52,996
2012	$ 377,500	$ 42,530	$ -	$ -	$ -	$ -	$ -	$ 48,182	$ -	$ 54,851
2013	$ 390,921	$ 44,018	$ -	$ -	$ -	$ -	$ -	$ 49,869	$ -	$ 56,771
2014	$ 379,419	$ 45,559	$ -	$ -	$ -	$ -	$ -	$ 51,614	$ -	$ 58,758
2015	$ 366,468	$ 47,154	$ -	$ -	$ -	$ -	$ -	$ 53,421	$ -	$ 60,814
2016	$ 380,409	$ 48,947	$ -	$ -	$ -	$ -	$ -	$ 55,453	$ -	$ 63,128
2017	$ 366,194	$ 50,741	$ -	$ -	$ -	$ -	$ -	$ 57,485	$ -	$ 65,441
2018	$ 379,140	$ 52,535	$ -	$ -	$ -	$ -	$ -	$ 59,517	$ -	$ 67,755
2019	$ 323,537	$ 54,585	$ -	$ -	$ -	$ -	$ -	$ 61,840	$ -	$ -
2020	$ 335,688	$ 56,636	$ -	$ -	$ -	$ -	$ -	$ 64,163	$ -	$ -
2021	$ 315,688	$ 58,763	$ -	$ -	$ -	$ -	$ -	$ 66,573	$ -	$ -
2022	$ 266,575	$ -	$ -	$ -	$ -	$ -	$ -	$ 69,073	$ -	$ -
2023	$ 276,587	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,667	$ -	$ -
2024	$ 286,975	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,359	$ -	$ -
2025	$ 227,262	$ -	$ -	$ -	$ -	$ -	$ -	$ 77,152	$ -	$ -
2026	$ 155,748	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 161,598	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 167,667	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 173,965	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue
(000)

Fuel Cost	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
1999	$ 32,367	$ 32,367	$ 25,900	$ 17,961	$ 17,961	$ 18,069	$ 18,069	$ -	$ -
2000	$ 32,091	$ 32,091	$ 32,019	$ 17,663	$ 17,663	$ 17,768	$ 17,768	$ -	$ -
2001	$ 32,193	$ 32,193	$ 34,703	$ 17,469	$ 17,469	$ 17,573	$ 17,573	$ -	$ -
2002	$ 32,672	$ 32,672	$ 38,149	$ 17,595	$ 17,595	$ 17,700	$ 17,700	$ -	$ -
2003	$ 33,042	$ 33,042	$ 42,309	$ 17,709	$ 17,709	$ 17,815	$ 17,815	$ -	$ -
2004	$ 33,405	$ 33,405	$ 46,476	$ 17,955	$ 17,955	$ 18,063	$ 18,063	$ -	$ -
2005	$ 33,986	$ 33,986	$ 50,210	$ 18,325	$ 18,325	$ 18,434	$ 18,434	$ -	$ -
2006	$ 35,366	$ 35,366	$ 46,698	$ 18,977	$ 18,977	$ 19,068	$ 19,068	$ -	$ -
2007	$ 36,746	$ 36,746	$ 43,622	$ 19,648	$ 19,648	$ 19,742	$ 19,742	$ -	$ -
2008	$ 38,198	$ 38,198	$ 44,945	$ 20,356	$ 20,356	$ 20,478	$ 20,478	$ -	$ -
2009	$ 39,525	$ 39,525	$ 46,057	$ 21,063	$ 21,063	$ 21,164	$ 21,164	$ -	$ -
2010	$ 41,116	$ 41,116	$ 46,417	$ 21,911	$ 21,911	$ 22,042	$ 22,042	$ -	$ -
2011	$ 42,443	$ 42,443	$ 48,041	$ 22,618	$ 22,618	$ 22,753	$ 22,753	$ -	$ -
2012	$ 44,034	$ 44,034	$ 49,723	$ 23,466	$ 23,466	$ 23,607	$ 23,607	$ -	$ -
2013	$ 45,626	$ 45,626	$ 51,463	$ 24,314	$ 24,314	$ 24,460	$ 24,460	$ -	$ -
2014	$ 47,217	$ 47,217	$ 53,264	$ -	$ 25,162	$ 25,313	$ 25,313	$ -	$ -
2015	$ 48,809	$ 48,809	$ 55,129	$ -	$ -	$ 26,166	$ 26,166	$ -	$ -
2016	$ 50,666	$ 50,666	$ 57,226	$ -	$ -	$ 27,162	$ 27,162	$ -	$ -
2017	$ 52,523	$ 52,523	$ 59,323	$ -	$ -	$ -	$ 28,157	$ -	$ -
2018	$ 54,380	$ 54,380	$ 61,421	$ -	$ -	$ -	$ 29,153	$ -	$ -
2019	$ 56,502	$ 56,502	$ 63,817	$ -	$ -	$ -	$ 30,290	$ -	$ -
2020	$ 58,624	$ 58,624	$ 66,214	$ -	$ -	$ -	$ 31,428	$ -	$ -
2021	$ 60,826	$ 60,826	$ 68,701	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 63,110	$ 63,110	$ 71,282	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 65,481	$ 65,481	$ 73,959	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 67,940	$ 67,940	$ 76,737	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 70,492	$ 79,619	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 73,139	$ 82,609	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 75,886	$ 85,712	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 78,736	$ 88,931	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 81,694	$ 92,271	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Operating & Maintenance Projection										
1999	$ 507,198	$ 8,047	$ 10,661	$ 11,438	$ 4,062	$ 5,019	$ 20,355	$ 19,265	$ 9,530	$ 7,138
2000	$ 508,766	$ 8,268	$ 10,954	$ 11,795	$ -	$ -	$ 21,004	$ 19,888	$ 9,792	$ 7,335
2001	$ 522,294	$ 8,490	$ 11,248	$ 12,154	$ -	$ -	$ 21,704	$ 20,564	$ 10,054	$ 7,531
2002	$ 540,319	$ 8,785	$ 11,639	$ 12,622	$ -	$ -	$ 22,600	$ 21,477	$ 10,404	$ 7,793
2003	$ 559,040	$ 9,006	$ 11,932	$ 14,663	$ -	$ -	$ 24,235	$ 23,678	$ 10,666	$ 7,990
2004	$ 577,443	$ 9,302	$ 12,323	$ 15,269	$ -	$ -	$ 25,248	$ 24,691	$ 11,016	$ 8,252
2005	$ 579,872	$ 9,597	$ 12,715	$ -	$ -	$ -	$ 26,218	$ 25,658	$ 11,366	$ 8,514
2006	$ 601,348	$ 9,966	$ 13,204	$ -	$ -	$ -	$ 27,168	$ 26,645	$ 11,803	$ 8,841
2007	$ 618,526	$ 10,261	$ 13,595	$ -	$ -	$ -	$ 27,973	$ 27,434	$ 12,153	$ 9,103
2008	$ 640,545	$ 10,630	$ 14,084	$ -	$ -	$ -	$ 29,166	$ 28,556	$ 12,590	$ 9,430
2009	$ 662,335	$ 10,999	$ 14,573	$ -	$ -	$ -	$ 30,243	$ 29,618	$ 13,027	$ 9,758
2010	$ 688,540	$ 11,442	$ 15,160	$ -	$ -	$ -	$ 31,595	$ 30,956	$ 13,551	$ 10,151
2011	$ 663,619	$ 11,812	$ 15,649	$ -	$ -	$ -	$ -	$ 31,955	$ -	$ 10,478
2012	$ 687,890	$ 12,254	$ 16,236	$ -	$ -	$ -	$ -	$ 33,153	$ -	$ 10,871
2013	$ 712,161	$ 12,697	$ 16,822	$ -	$ -	$ -	$ -	$ 34,352	$ -	$ 11,264
2014	$ 675,311	$ 13,140	$ 17,409	$ -	$ -	$ -	$ -	$ 35,550	$ -	$ 11,657
2015	$ 634,340	$ 13,583	$ 17,996	$ -	$ -	$ -	$ -	$ 36,748	$ -	$ 12,050
2016	$ 657,849	$ 14,100	$ 18,681	$ -	$ -	$ -	$ -	$ 38,146	$ -	$ 12,508
2017	$ 561,046	$ 14,617	$ 19,365	$ -	$ -	$ -	$ -	$ 39,544	$ -	$ 12,967
2018	$ 580,301	$ 15,134	$ 20,050	$ -	$ -	$ -	$ -	$ 40,942	$ -	$ 13,425
2019	$ 588,358	$ 15,724	$ 20,832	$ -	$ -	$ -	$ -	$ 42,540	$ -	$ -
2020	$ 609,840	$ 16,315	$ 21,615	$ -	$ -	$ -	$ -	$ 44,138	$ -	$ -
2021	$ 492,798	$ 16,927	$ 22,427	$ -	$ -	$ -	$ -	$ 45,796	$ -	$ -
2022	$ 467,756	$ -	$ 23,269	$ -	$ -	$ -	$ -	$ 47,516	$ -	$ -
2023	$ 484,708	$ -	$ 24,143	$ -	$ -	$ -	$ -	$ 49,300	$ -	$ -
2024	$ 502,297	$ -	$ 25,050	$ -	$ -	$ -	$ -	$ 51,152	$ -	$ -
2025	$ 310,352	$ -	$ 25,991	$ -	$ -	$ -	$ -	$ 53,073	$ -	$ -
2026	$ 266,634	$ -	$ 26,967	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 276,340	$ -	$ 27,980	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 286,411	$ -	$ 29,031	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 296,861	$ -	$ 30,121	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue E
(000)

Operating & Maintenance Projection	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
1999	$ 91,054	$ 91,054	$ 8,711	$ 37,428	$ 37,428	$ 66,232	$ 66,232	$ 2,844	$ 10,702
2000	$ 93,334	$ 93,334	$ 9,040	$ 38,458	$ 38,458	$ 68,055	$ 68,055	$ -	$ 10,996
2001	$ 95,614	$ 95,614	$ 9,298	$ 39,488	$ 39,488	$ 69,878	$ 69,878	$ -	$ 11,291
2002	$ 98,655	$ 98,655	$ 9,665	$ 40,862	$ 40,862	$ 72,309	$ 72,309	$ -	$ 11,683
2003	$ 100,935	$ 100,935	$ 9,943	$ 41,892	$ 41,892	$ 74,131	$ 74,131	$ -	$ 13,010
2004	$ 103,976	$ 103,976	$ 10,300	$ 43,265	$ 43,265	$ 76,562	$ 76,562	$ -	$ 13,437
2005	$ 107,016	$ 107,016	$ 10,647	$ 44,639	$ 44,639	$ 78,993	$ 78,993	$ -	$ 13,863
2006	$ 110,817	$ 110,817	$ 10,919	$ 46,356	$ 46,356	$ 82,031	$ 82,031	$ -	$ 14,397
2007	$ 113,857	$ 113,857	$ 11,089	$ 47,729	$ 47,729	$ 84,461	$ 84,461	$ -	$ 14,823
2008	$ 117,658	$ 117,658	$ 11,525	$ 49,446	$ 49,446	$ 87,499	$ 87,499	$ -	$ 15,356
2009	$ 121,459	$ 121,459	$ 11,910	$ 51,163	$ 51,163	$ 90,538	$ 90,538	$ -	$ 15,890
2010	$ 126,019	$ 126,019	$ 12,303	$ 53,223	$ 53,223	$ 94,183	$ 94,183	$ -	$ 16,529
2011	$ 129,820	$ 129,820	$ 12,700	$ 54,940	$ 54,940	$ 97,222	$ 97,222	$ -	$ 17,063
2012	$ 134,381	$ 134,381	$ 13,176	$ 57,000	$ 57,000	$ 100,867	$ 100,867	$ -	$ 17,703
2013	$ 138,942	$ 138,942	$ 13,653	$ 59,061	$ 59,061	$ 104,513	$ 104,513	$ -	$ 18,342
2014	$ 143,502	$ 143,502	$ 14,129	$ -	$ 61,121	$ 108,159	$ 108,159	$ -	$ 18,982
2015	$ 148,063	$ 148,063	$ 14,605	$ -	$ -	$ 111,805	$ 111,805	$ -	$ 19,622
2016	$ 153,384	$ 153,384	$ 15,161	$ -	$ -	$ 116,058	$ 116,058	$ -	$ 20,369
2017	$ 158,705	$ 158,705	$ 15,716	$ -	$ -	$ -	$ 120,312	$ -	$ 21,115
2018	$ 164,026	$ 164,026	$ 16,272	$ -	$ -	$ -	$ 124,565	$ -	$ 21,862
2019	$ 170,107	$ 170,107	$ 16,907	$ -	$ -	$ -	$ 129,426	$ -	$ 22,715
2020	$ 176,188	$ 176,188	$ 17,542	$ -	$ -	$ -	$ 134,287	$ -	$ 23,568
2021	$ 182,497	$ 182,497	$ 18,201	$ -	$ -	$ -	$ -	$ -	$ 24,453
2022	$ 189,043	$ 189,043	$ 18,884	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 195,836	$ 195,836	$ 19,594	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 202,883	$ 202,883	$ 20,330	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 210,195	$ 21,093	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 217,782	$ 21,885	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 225,653	$ 22,707	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 233,821	$ 23,560	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 242,295	$ 24,445	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue Estimates
(000)

Capital Expenditure Projection	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
1999	$ 98,477	$ 2,054	$ 1,467	$ 1,572	$ 943	$ 1,677	$ 1,887	$ 1,887	$ 1,887	$ 2,893
2000	$ 97,634	$ 2,111	$ 1,508	$ 1,615	$ -	$ -	$ 1,938	$ 1,938	$ 1,938	$ 2,972
2001	$ 100,249	$ 2,167	$ 1,548	$ 1,659	$ -	$ -	$ 1,990	$ 1,990	$ 1,990	$ 3,052
2002	$ 103,736	$ 2,243	$ 1,602	$ 1,716	$ -	$ -	$ 2,060	$ 2,060	$ 2,060	$ 3,158
2003	$ 106,351	$ 2,299	$ 1,642	$ 1,760	$ -	$ -	$ 2,112	$ 2,112	$ 2,112	$ 3,238
2004	$ 109,838	$ 2,375	$ 1,696	$ 1,817	$ -	$ -	$ 2,181	$ 2,181	$ 2,181	$ 3,344
2005	$ 111,450	$ 2,450	$ 1,750	$ -	$ -	$ -	$ 2,250	$ 2,250	$ 2,250	$ 3,450
2006	$ 115,737	$ 2,544	$ 1,817	$ -	$ -	$ -	$ 2,337	$ 2,337	$ 2,337	$ 3,583
2007	$ 119,166	$ 2,620	$ 1,871	$ -	$ -	$ -	$ 2,406	$ 2,406	$ 2,406	$ 3,689
2008	$ 123,452	$ 2,714	$ 1,938	$ -	$ -	$ -	$ 2,492	$ 2,492	$ 2,492	$ 3,822
2009	$ 127,739	$ 2,808	$ 2,006	$ -	$ -	$ -	$ 2,579	$ 2,579	$ 2,579	$ 3,954
2010	$ 132,883	$ 2,921	$ 2,087	$ -	$ -	$ -	$ 2,683	$ 2,683	$ 2,683	$ 4,113
2011	$ 131,631	$ 3,015	$ 2,154	$ -	$ -	$ -	$ -	$ 2,769	$ -	$ 4,246
2012	$ 136,567	$ 3,128	$ 2,235	$ -	$ -	$ -	$ -	$ 2,873	$ -	$ 4,405
2013	$ 141,503	$ 3,242	$ 2,315	$ -	$ -	$ -	$ -	$ 2,977	$ -	$ 4,565
2014	$ 133,531	$ 3,355	$ 2,396	$ -	$ -	$ -	$ -	$ 3,081	$ -	$ 4,724
2015	$ 123,096	$ 3,468	$ 2,477	$ -	$ -	$ -	$ -	$ 3,185	$ -	$ 4,883
2016	$ 127,779	$ 3,600	$ 2,571	$ -	$ -	$ -	$ -	$ 3,306	$ -	$ 5,069
2017	$ 118,103	$ 3,732	$ 2,665	$ -	$ -	$ -	$ -	$ 3,427	$ -	$ 5,255
2018	$ 122,279	$ 3,863	$ 2,760	$ -	$ -	$ -	$ -	$ 3,548	$ -	$ 5,440
2019	$ 121,398	$ 4,014	$ 2,867	$ -	$ -	$ -	$ -	$ 3,687	$ -	$ -
2020	$ 125,957	$ 4,165	$ 2,975	$ -	$ -	$ -	$ -	$ 3,825	$ -	$ -
2021	$ 114,059	$ 4,321	$ 3,087	$ -	$ -	$ -	$ -	$ 3,969	$ -	$ -
2022	$ 113,860	$ -	$ 3,203	$ -	$ -	$ -	$ -	$ 4,118	$ -	$ -
2023	$ 118,136	$ -	$ 3,323	$ -	$ -	$ -	$ -	$ 4,272	$ -	$ -
2024	$ 122,573	$ -	$ 3,448	$ -	$ -	$ -	$ -	$ 4,433	$ -	$ -
2025	$ 69,082	$ -	$ 3,577	$ -	$ -	$ -	$ -	$ 4,599	$ -	$ -
2026	$ 66,905	$ -	$ 3,712	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 69,417	$ -	$ 3,851	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 72,025	$ -	$ 3,996	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 74,730	$ -	$ 4,146	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue E
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Capital Expenditure Projection									
1999	$ 23,829	$ 23,829	$ 1,153	$ 7,905	$ 7,905	$ 7,905	$ 7,905	$ 838	$ 943
2000	$ 24,485	$ 24,485	$ 1,185	$ 8,122	$ 8,122	$ 8,122	$ 8,122	$ -	$ 969
2001	$ 25,141	$ 25,141	$ 1,216	$ 8,340	$ 8,340	$ 8,340	$ 8,340	$ -	$ 995
2002	$ 26,015	$ 26,015	$ 1,259	$ 8,630	$ 8,630	$ 8,630	$ 8,630	$ -	$ 1,030
2003	$ 26,671	$ 26,671	$ 1,290	$ 8,847	$ 8,847	$ 8,847	$ 8,847	$ -	$ 1,056
2004	$ 27,546	$ 27,546	$ 1,333	$ 9,137	$ 9,137	$ 9,137	$ 9,137	$ -	$ 1,090
2005	$ 28,420	$ 28,420	$ 1,375	$ 9,428	$ 9,428	$ 9,428	$ 9,428	$ -	$ 1,125
2006	$ 29,513	$ 29,513	$ 1,428	$ 9,790	$ 9,790	$ 9,790	$ 9,790	$ -	$ 1,168
2007	$ 30,388	$ 30,388	$ 1,470	$ 10,080	$ 10,080	$ 10,080	$ 10,080	$ -	$ 1,203
2008	$ 31,481	$ 31,481	$ 1,523	$ 10,443	$ 10,443	$ 10,443	$ 10,443	$ -	$ 1,246
2009	$ 32,574	$ 32,574	$ 1,576	$ 10,805	$ 10,805	$ 10,805	$ 10,805	$ -	$ 1,289
2010	$ 33,885	$ 33,885	$ 1,639	$ 11,240	$ 11,240	$ 11,240	$ 11,240	$ -	$ 1,341
2011	$ 34,978	$ 34,978	$ 1,692	$ 11,603	$ 11,603	$ 11,603	$ 11,603	$ -	$ 1,385
2012	$ 36,290	$ 36,290	$ 1,756	$ 12,038	$ 12,038	$ 12,038	$ 12,038	$ -	$ 1,437
2013	$ 37,602	$ 37,602	$ 1,819	$ 12,473	$ 12,473	$ 12,473	$ 12,473	$ -	$ 1,488
2014	$ 38,914	$ 38,914	$ 1,883	$ -	$ 12,908	$ 12,908	$ 12,908	$ -	$ 1,540
2015	$ 40,225	$ 40,225	$ 1,946	$ -	$ -	$ 13,344	$ 13,344	$ -	$ -
2016	$ 41,756	$ 41,756	$ 2,020	$ -	$ -	$ 13,851	$ 13,851	$ -	$ -
2017	$ 43,286	$ 43,286	$ 2,094	$ -	$ -	$ -	$ 14,359	$ -	$ -
2018	$ 44,816	$ 44,816	$ 2,168	$ -	$ -	$ -	$ 14,866	$ -	$ -
2019	$ 46,565	$ 46,565	$ 2,253	$ -	$ -	$ -	$ 15,447	$ -	$ -
2020	$ 48,314	$ 48,314	$ 2,338	$ -	$ -	$ -	$ 16,027	$ -	$ -
2021	$ 50,129	$ 50,129	$ 2,425	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 52,011	$ 52,011	$ 2,516	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 53,965	$ 53,965	$ 2,611	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 55,992	$ 55,992	$ 2,709	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 58,095	$ 2,811	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 60,277	$ 2,916	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 62,541	$ 3,026	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 64,889	$ 3,139	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 67,327	$ 3,257	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Administrative & General Projection										
Allocated to Stations*										
1999	$ 64,014	$ -	$ 1,933	$ 1,865	$ 730	$ 910	$ 3,455	$ 2,885	$ 1,728	$ -
2000	$ 63,560	$ -	$ 1,987	$ 1,916	$ -	$ -	$ 3,550	$ 2,964	$ 1,776	$ -
2001	$ 65,262	$ -	$ 2,040	$ 1,968	$ -	$ -	$ 3,645	$ 3,044	$ 1,823	$ -
2002	$ 67,532	$ -	$ 2,111	$ 2,036	$ -	$ -	$ 3,772	$ 3,149	$ 1,887	$ -
2003	$ 69,235	$ -	$ 2,164	$ 2,088	$ -	$ -	$ 3,867	$ 3,229	$ 1,934	$ -
2004	$ 71,505	$ -	$ 2,235	$ 2,156	$ -	$ -	$ 3,994	$ 3,335	$ 1,998	$ -
2005	$ 71,550	$ -	$ 2,306	$ -	$ -	$ -	$ 4,121	$ 3,440	$ 2,061	$ -
2006	$ 74,302	$ -	$ 2,395	$ -	$ -	$ -	$ 4,279	$ 3,573	$ 2,141	$ -
2007	$ 76,504	$ -	$ 2,466	$ -	$ -	$ -	$ 4,406	$ 3,679	$ 2,204	$ -
2008	$ 79,256	$ -	$ 2,554	$ -	$ -	$ -	$ 4,565	$ 3,811	$ 2,283	$ -
2009	$ 82,008	$ -	$ 2,643	$ -	$ -	$ -	$ 4,723	$ 3,943	$ 2,363	$ -
2010	$ 85,310	$ -	$ 2,749	$ -	$ -	$ -	$ 4,913	$ 4,102	$ 2,458	$ -
2011	$ 80,453	$ -	$ 2,838	$ -	$ -	$ -	$ -	$ 4,234	$ -	$ -
2012	$ 83,470	$ -	$ 2,945	$ -	$ -	$ -	$ -	$ 4,393	$ -	$ -
2013	$ 86,487	$ -	$ 3,051	$ -	$ -	$ -	$ -	$ 4,552	$ -	$ -
2014	$ 78,419	$ -	$ 3,157	$ -	$ -	$ -	$ -	$ 4,711	$ -	$ -
2015	$ 66,674	$ -	$ 3,264	$ -	$ -	$ -	$ -	$ 4,870	$ -	$ -
2016	$ 69,211	$ -	$ 3,388	$ -	$ -	$ -	$ -	$ 5,055	$ -	$ -
2017	$ 71,747	$ -	$ 3,512	$ -	$ -	$ -	$ -	$ 5,240	$ -	$ -
2018	$ 74,284	$ -	$ 3,636	$ -	$ -	$ -	$ -	$ 5,425	$ -	$ -
2019	$ 77,183	$ -	$ 3,778	$ -	$ -	$ -	$ -	$ 5,637	$ -	$ -
2020	$ 80,081	$ -	$ 3,920	$ -	$ -	$ -	$ -	$ 5,849	$ -	$ -
2021	$ 83,089	$ -	$ 4,067	$ -	$ -	$ -	$ -	$ 6,068	$ -	$ -
2022	$ 86,210	$ -	$ 4,220	$ -	$ -	$ -	$ -	$ 6,296	$ -	$ -
2023	$ 89,448	$ -	$ 4,379	$ -	$ -	$ -	$ -	$ 6,533	$ -	$ -
2024	$ 92,807	$ -	$ 4,543	$ -	$ -	$ -	$ -	$ 6,778	$ -	$ -
2025	$ 55,859	$ -	$ 4,714	$ -	$ -	$ -	$ -	$ 7,033	$ -	$ -
2026	$ 50,660	$ -	$ 4,891	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 52,563	$ -	$ 5,074	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 54,537	$ -	$ 5,265	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 56,585	$ -	$ 5,463	$ -	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

EDS - Utilizing J. Bustard's Market Revenue E
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Administrative & General Projection									
Allocated to Stations*									
1999	$ 16,585	$ 16,585	$ 1,509	$ 6,788	$ 6,788	$ -	$ -	$ 516	$ 1,736
2000	$ 17,042	$ 17,042	$ 1,550	$ 6,975	$ 6,975	$ -	$ -	$ -	$ 1,783
2001	$ 17,498	$ 17,498	$ 1,592	$ 7,162	$ 7,162	$ -	$ -	$ -	$ 1,831
2002	$ 18,107	$ 18,107	$ 1,647	$ 7,411	$ 7,411	$ -	$ -	$ -	$ 1,895
2003	$ 18,563	$ 18,563	$ 1,689	$ 7,598	$ 7,598	$ -	$ -	$ -	$ 1,943
2004	$ 19,172	$ 19,172	$ 1,744	$ 7,847	$ 7,847	$ -	$ -	$ -	$ 2,006
2005	$ 19,780	$ 19,780	$ 1,800	$ 8,096	$ 8,096	$ -	$ -	$ -	$ 2,070
2006	$ 20,541	$ 20,541	$ 1,869	$ 8,407	$ 8,407	$ -	$ -	$ -	$ 2,150
2007	$ 21,150	$ 21,150	$ 1,924	$ 8,656	$ 8,656	$ -	$ -	$ -	$ 2,213
2008	$ 21,911	$ 21,911	$ 1,993	$ 8,968	$ 8,968	$ -	$ -	$ -	$ 2,293
2009	$ 22,671	$ 22,671	$ 2,063	$ 9,279	$ 9,279	$ -	$ -	$ -	$ 2,372
2010	$ 23,584	$ 23,584	$ 2,146	$ 9,653	$ 9,653	$ -	$ -	$ -	$ 2,468
2011	$ 24,345	$ 24,345	$ 2,215	$ 9,964	$ 9,964	$ -	$ -	$ -	$ 2,548
2012	$ 25,258	$ 25,258	$ 2,298	$ 10,338	$ 10,338	$ -	$ -	$ -	$ 2,643
2013	$ 26,171	$ 26,171	$ 2,381	$ 10,711	$ 10,711	$ -	$ -	$ -	$ 2,739
2014	$ 27,084	$ 27,084	$ 2,464	$ -	$ 11,085	$ -	$ -	$ -	$ 2,834
2015	$ 27,997	$ 27,997	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ 29,062	$ 29,062	$ 2,644	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ 30,127	$ 30,127	$ 2,741	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ 31,192	$ 31,192	$ 2,838	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ 32,409	$ 32,409	$ 2,948	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ 33,627	$ 33,627	$ 3,059	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ 34,890	$ 34,890	$ 3,174	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 36,200	$ 36,200	$ 3,293	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 37,560	$ 37,560	$ 3,417	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 38,970	$ 38,970	$ 3,545	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 40,434	$ 3,679	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 41,953	$ 3,817	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 43,528	$ 3,960	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 45,163	$ 4,109	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 46,859	$ 4,263	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)

Other Taxes	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
*Allocated to Stations**										
1999	$ 104,936	$ -	$ 3,169	$ 3,057	$ 1,197	$ 1,492	$ 5,664	$ 4,729	$ 2,833	$ -
2000	$ 101,401	$ -	$ 3,169	$ 3,057	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2001	$ 101,401	$ -	$ 3,169	$ 3,057	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2002	$ 101,401	$ -	$ 3,169	$ 3,057	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2003	$ 101,401	$ -	$ 3,169	$ 3,057	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2004	$ 101,401	$ -	$ 3,169	$ 3,057	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2005	$ 98,344	$ -	$ 3,169	$ -	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2006	$ 98,344	$ -	$ 3,169	$ -	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2007	$ 98,344	$ -	$ 3,169	$ -	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2008	$ 98,344	$ -	$ 3,169	$ -	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2009	$ 98,344	$ -	$ 3,169	$ -	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2010	$ 98,344	$ -	$ 3,169	$ -	$ -	$ -	$ 5,664	$ 4,729	$ 2,833	$ -
2011	$ 89,847	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2012	$ 89,847	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2013	$ 89,847	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2014	$ 78,719	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2015	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2016	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2017	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2018	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2019	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2020	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2021	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2022	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2023	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2024	$ 64,747	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2025	$ 37,559	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ 4,729	$ -	$ -
2026	$ 32,830	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 32,830	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 32,830	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 32,830	$ -	$ 3,169	$ -	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

EDS - Utilizing J. Bustard's Market Revenue E

(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Other Taxes									
Allocated to Stations*									
1999	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ 845	$ 2,845
2000	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2001	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2002	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2003	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2004	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2005	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2006	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2007	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2008	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2009	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2010	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2011	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2012	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2013	$ 27,188	$ 27,188	$ 2,473	$ 11,127	$ 11,127	$ -	$ -	$ -	$ 2,845
2014	$ 27,188	$ 27,188	$ 2,473	$ -	$ 11,127	$ -	$ -	$ -	$ 2,845
2015	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 27,188	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 27,188	$ 2,473	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Decommissioning										
1999	$ 31,344	$ 1,280	$ -	$ 366	$ 522	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2000	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2001	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2002	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2003	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2004	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2005	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2006	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2007	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2008	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2009	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2010	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2011	$ 26,984	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2012	$ 26,984	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2013	$ 26,984	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2014	$ 21,572	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2015	$ 16,165	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2016	$ 16,165	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2017	$ 13,539	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2018	$ 13,539	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ 1,298
2019	$ 12,241	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ -
2020	$ 12,241	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ -
2021	$ 10,302	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ -
2022	$ 9,022	$ -	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ -
2023	$ 9,022	$ -	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ -
2024	$ 9,022	$ -	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ -
2025	$ 5,906	$ -	$ -	$ -	$ -	$ -	$ -	$ 768	$ -	$ -
2026	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue E
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Decommissioning									
1999	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2000	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2001	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2002	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2003	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2004	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2005	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2006	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2007	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2008	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2009	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2010	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2011	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2012	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2013	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2014	$ 3,116	$ 5,138	$ -	$ -	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2015	$ 3,116	$ 5,138	$ -	$ -	$ -	$ 2,626	$ 1,939	$ -	$ -
2016	$ 3,116	$ 5,138	$ -	$ -	$ -	$ 2,626	$ 1,939	$ -	$ -
2017	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2018	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2019	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2020	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2021	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Required Life Extension Costs										
1999	$ 20,962	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2003	$ 87,981	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 87,981
2004	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2006	$ 97,356	$ 97,356	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2007	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ 76,010	$ -	$ -	$ -	$ -	$ -	$ -	$ 76,010	$ -	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 51,346	$ -	$ 17,115	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

EDS - Utilizing J. Bustard's Market Revenue E
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Required Life Extension Costs									
1999	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,962
2000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2003	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2004	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2006	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2007	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ -	$ -	$ 34,231	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Present Value of Contribution Margin

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

Plant Name	(000) Net Present Value
Conemaugh	$ 268,495
Conowingo	490,611
Cromby 1	(9,060)
Cromby 2	(951)
Delaware	(804)
Eddystone 1	(9,580)
Eddystone 2	19,541
Eddystone3&4	105,149
Keystone	189,926
Limerick 1	365,721
Limerick 2	418,514
Muddy Run	259,189
P. Bottom 2	48,344
P. Bottom 3	53,492
Salem 1	34,940
Salem 2	48,756
Schuylkill	(456)
C. Turbines	74,349
Total NPV of Contribution Margin	**$ 2,356,176**
Total NPV excluding Negative Values	**$ 2,377,027**
Inventory and Working Capital Carrying Charges	(162,363)
Future Tax Depreciation Benefits	270,512
Accumulated Deferred Investment Tax Credit Benefits	133,360
Deferred Income Tax	400,598
Total Adjusted NPV excluding Negative Values	**$ 3,019,134**

Exhibit TPH-3

Market Value of Generating Units by Year

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Net Present Value	$2,356,176	$268,495	$490,611	($9,060)	($951)	($804)	($9,580)	$19,541	$105,149	$189,926

(Market Value Revenue - Est. Fuel Cost - Est. O&M - Est. Capital - A&G - Taxes - Decomm. - Required Life Extension*) x (1-T)*

*After-Tax Cash Contribution Margin***				***						
1999	$ 10,808	$ 14,074	$ 23,745	$ (2,023)	$ (1,035)	$ (876)	$ (3,588)	$ (3,100)	$ (793)	$ 14,647
2000	$ 59,365	$ 16,857	$ 26,684	$ (2,023)	$ -	$ -	$ (3,588)	$ (3,100)	$ 1,293	$ 14,213
2001	$ 97,501	$ 19,495	$ 29,900	$ (2,023)	$ -	$ -	$ (3,588)	$ (2,799)	$ 4,464	$ 16,799
2002	$ 174,871	$ 23,787	$ 35,498	$ (1,958)	$ -	$ -	$ (2,576)	$ 345	$ 10,795	$ 21,034
2003	$ 134,080	$ 25,024	$ 36,751	$ (2,023)	$ -	$ -	$ (2,607)	$ 54	$ 10,640	$ (29,994)
2004	$ 201,619	$ 26,508	$ 38,338	$ (2,023)	$ -	$ -	$ (2,086)	$ 675	$ 11,055	$ 22,105
2005	$ 227,007	$ 28,349	$ 40,477	$ -	$ -	$ -	$ (1,184)	$ 1,711	$ 11,954	$ 23,812
2006	$ 195,850	$ (26,479)	$ 43,002	$ -	$ -	$ -	$ (185)	$ 2,869	$ 13,000	$ 25,776
2007	$ 272,312	$ 32,205	$ 44,962	$ -	$ -	$ -	$ 516	$ 3,686	$ 13,524	$ 26,431
2008	$ 295,477	$ 34,217	$ 47,300	$ -	$ -	$ -	$ 1,297	$ 4,607	$ 14,168	$ 27,275
2009	$ 316,544	$ 36,024	$ 49,427	$ -	$ -	$ -	$ 2,108	$ 5,569	$ 14,748	$ 28,842
2010	$ 203,098	$ 38,123	$ 51,928	$ -	$ -	$ -	$ (41,467)	$ (37,830)	$ (33,383)	$ 30,652
2011	$ 357,797	$ 39,706	$ 53,816	$ -	$ -	$ -	$ 3,558	$ 7,324	$ 16,089	$ 31,989
2012	$ 377,706	$ 41,564	$ 56,062	$ -	$ -	$ -	$ 4,181	$ 8,099	$ 16,851	$ 33,553
2013	$ 396,482	$ 43,370	$ 58,384	$ -	$ -	$ -	$ 4,618	$ 8,673	$ 17,671	$ 33,814
2014	$ 365,368	$ 45,195	$ 50,708	$ -	$ -	$ -	$ 5,066	$ 9,259	$ 18,480	$ 34,007
2015	$ 378,510	$ 47,368	$ 63,163	$ -	$ -	$ -	$ 5,956	$ 10,323	$ 19,282	$ 35,802
2016	$ 395,339	$ 49,199	$ 65,636	$ -	$ -	$ -	$ 6,319	$ 10,834	$ 20,143	$ 37,193
2017	$ 398,735	$ 51,030	$ 68,109	$ -	$ -	$ -	$ 6,683	$ 11,345	$ 21,003	$ 38,584
2018	$ 415,035	$ 52,860	$ 70,583	$ -	$ -	$ -	$ 7,046	$ 11,856	$ 21,864	$ 39,974
2019	$ 392,099	$ 54,952	$ 73,409	$ -	$ -	$ -	$ 7,461	$ 12,439	$ 22,847	$ -
2020	$ 409,138	$ 57,044	$ 76,236	$ -	$ -	$ -	$ 7,876	$ 13,023	$ 23,831	$ -
2021	$ 410,615	$ 59,215	$ 79,169	$ -	$ -	$ -	$ 8,306	$ 13,628	$ 24,852	$ -
2022	$ 366,840	$ -	$ 82,212	$ -	$ -	$ -	$ 8,753	$ 14,257	$ 25,910	$ -
2023	$ 382,859	$ -	$ 85,369	$ -	$ -	$ -	$ 9,216	$ 14,909	$ 27,009	$ -
2024	$ 399,480	$ -	$ 88,645	$ -	$ -	$ -	$ 9,697	$ 15,585	$ 28,149	$ -
2025	$ 309,330	$ -	$ 92,044	$ -	$ -	$ -	$ 10,196	$ 16,287	$ 29,332	$ -
2026	$ 264,054	$ -	$ 95,571	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 274,989	$ -	$ 99,230	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 286,335	$ -	$ 103,026	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 298,106	$ -	$ 106,965	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

** Assumes all capital additions are currently tax deductible. Capital also includes required life extension costs.*

*** If contribution margin is negative then plant does not operate, but incurs taxes and decommissioning costs.*

**** Shaded areas indicate plant does not operate.*

Market Value of Generating Units by Year

ICF Resources, Inc. - Utilizing Dr. B. Venkat (000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Net Present Value	$365,721	$418,514	$259,189	$48,344	$53,492	$34,940	$48,756	($456)	$74,349
After-Tax Cash Contribution Margin*						***			
1999	$ (3,823)	$ (4,184)	$ 5,861	$ (6,651)	$ (6,648)	$ (1,536)	$ (1,135)	$ (496)	$ (11,634)
2000	$ 4,250	$ 3,980	$ 7,698	$ (3,213)	$ (3,210)	$ (1,536)	$ (1,135)	$ -	$ 2,194
2001	$ 10,691	$ 10,498	$ 12,007	$ (302)	$ (299)	$ (1,536)	$ (1,135)	$ -	$ 5,327
2002	$ 21,911	$ 21,843	$ 20,117	$ 4,511	$ 4,514	$ 1,432	$ 1,833	$ -	$ 11,787
2003	$ 24,236	$ 24,207	$ 20,752	$ 5,455	$ 5,459	$ 2,101	$ 2,502	$ -	$ 11,521
2004	$ 27,162	$ 27,183	$ 21,576	$ 6,554	$ 6,558	$ 2,830	$ 3,232	$ -	$ 11,953
2005	$ 30,992	$ 31,072	$ 23,120	$ 8,030	$ 8,034	$ 3,927	$ 4,329	$ -	$ 12,385
2006	$ 35,055	$ 35,203	$ 24,959	$ 9,619	$ 9,622	$ 5,040	$ 5,442	$ -	$ 12,926
2007	$ 38,553	$ 38,755	$ 25,960	$ 10,962	$ 10,965	$ 6,017	$ 6,418	$ -	$ 13,358
2008	$ 42,730	$ 43,001	$ 27,115	$ 12,568	$ 12,571	$ 7,164	$ 7,566	$ -	$ 13,898
2009	$ 46,257	$ 46,590	$ 28,387	$ 13,870	$ 13,874	$ 8,003	$ 8,405	$ -	$ 14,439
2010	$ 50,339	$ 50,745	$ 29,866	$ 15,370	$ 15,373	$ 8,946	$ 9,348	$ -	$ 15,088
2011	$ 53,103	$ 53,563	$ 31,010	$ 16,342	$ 16,346	$ 9,460	$ 9,862	$ -	$ 15,628
2012	$ 56,368	$ 56,894	$ 32,366	$ 17,489	$ 17,492	$ 10,055	$ 10,456	$ -	$ 16,277
2013	$ 59,814	$ 60,407	$ 33,503	$ 18,723	$ 18,727	$ 10,726	$ 11,128	$ -	$ 16,925
2014	$ 63,301	$ 63,961	$ 14,606	$ -	$ 19,979	$ 11,415	$ 11,817	$ -	$ 17,574
2015	$ 67,422	$ 68,155	$ 35,887	$ -	$ -	$ 12,375	$ 12,777	$ -	$ -
2016	$ 70,845	$ 71,652	$ 37,309	$ -	$ -	$ 12,904	$ 13,306	$ -	$ -
2017	$ 74,268	$ 75,148	$ 38,731	$ -	$ -	$ -	$ 13,835	$ -	$ -
2018	$ 77,692	$ 78,644	$ 40,153	$ -	$ -	$ -	$ 14,364	$ -	$ -
2019	$ 81,604	$ 82,639	$ 41,778	$ -	$ -	$ -	$ 14,969	$ -	$ -
2020	$ 85,516	$ 86,635	$ 43,403	$ -	$ -	$ -	$ 15,574	$ -	$ -
2021	$ 89,575	$ 90,781	$ 45,089	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 93,787	$ 95,082	$ 46,839	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 98,157	$ 99,545	$ 48,654	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 102,691	$ 104,175	$ 50,537	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 108,980	$ 52,491	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 113,965	$ 54,519	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 119,137	$ 56,622	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 124,503	$ 58,805	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 130,071	$ 61,070	$ -	$ -	$ -	$ -	$ -	$ -

** *If contribution margin is negative then plant does not operate, but incurs taxes and decommissioning costs.*

*** *Shaded areas indicate plant does not operate.*

Operating Assumptions

Data Inputs			Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Plant Name												
Capacity (MW)			9,029	332	512	345		250	1,341			340
Case Description:			ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates									
Plant Type				Coal	Water	Coal	Gas	Oil	Coal	Coal	Gas	Coal
Decommissioning:												
Decommissioning Year - Adjusted				2021	2029	2004	1999	1999	2025	2025	2025	2018
Decommissioning Year - Nameplate				2006	2014	2004	1999	1999	2010	2010	2010	2003
Life Extension Years				15	15	0	0	0	15	15	15	15
Required Life Extension Costs	1997	$	358,000	$ 75,000	$ 10,000	$ -	$ -	$ -	$ 51,000	$ 51,000	$ 56,000	$ 75,000
Decommissioning Exp.	Flat	$	31,344	$ 1,280	$ -	$ 366	$ 522	$ -	$ 710	$ 768	$ 2,762	$ 1,298
O&M Buildup:												
Fixed Charge - $000	1997	$	444,432	$ 7,677	$ 8,950	$ 6,762	$ 3,842	$ 4,789	$ 11,582	$ 9,528	$ 9,093	$ 6,811
Incremental Charge - $/MWhr	1997			$ -	$ 0.69	$ 3.38	$ 0.51	$ 1.68	$ 4.07	$ 3.24	$ 0.48	$ -
NOX 1999-2002 $/MWhr	1997			$ -	$ -	$ 1.09	$ 1.43	$ 0.20	$ 0.64	$ 1.69	$ 0.79	$ -
NOX 2003&Thereafter $/MWhr	1997			$ -	$ -	$ 2.52	$ 3.10	$ 0.76	$ 1.06	$ 2.34	$ 1.81	$ -
Merrill Creek	Flat	$	16,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1997 Operating & Maintenance - Base		$	476,948	$ 7,677	$ 10,135	$ 9,900	$ 3,994	$ 4,793	$ 17,365	$ 14,511	$ 9,443	$ 6,811
1996 Operating & Maintenance -Estimate		$	493,881	$ -	$ 8,555	$ 8,659	$ 5,146	$ 5,220	$ 17,706	$ 13,982	$ 8,342	$ -
1995 Operating & Maintenance - Actual		$	486,254	$ 10,758	$ 8,018	$ 8,849	$ 7,398	$ 7,736	$ 23,358	$ 16,841	$ 6,915	$ 9,685
1994 Operating & Maintenance - Actual		$	507,353	$ 11,395	$ 9,942	$ 14,466	$ 5,540	$ 7,742	$ 25,813	$ 21,560	$ 19,702	$ 10,933
Capital Expenditures:												
1997 Capital Expenditures Base			93,960	$ 1,960	$ 1,400	$ 1,500	$ 900	$ 1,600	$ 1,800	$ 1,800	$ 1,800	$ 2,760
1996 Capital Expenditures Estimate			203,205	$ 5,196	$ 13,306	$ 140	$ 1,654	$ 100	$ 1,154	$ 1,124	$ 890	$ 3,761
1995 Capital Expenditures Actual			169,267	$ 8,751	$ 5,958	$ 429	$ 3,334	$ 154	$ 8,415	$ 5,141	$ 3,573	$ 7,275
1994 Capital Expenditures Actual			158,081	$ -	$ 943	$ 10,217	$ 827	$ 1,617	$ 5,895	$ 4,393	$ 13,223	$ -
Other Costs:												
Admin & General Exp.	1995	$	58,728	$ -	$ 1,771	$ 1,730	$ 698	$ 838	$ 3,035	$ 2,536	$ 1,650	$ -
Other Taxes	1995	$	104,936	$ -	$ 3,165	$ 3,091	$ 1,247	$ 1,497	$ 5,422	$ 4,531	$ 2,949	$ -
Allocation Factors:												
1997 O&M ex Salem,Keystone&Conemaugh			336,072	$ -	$ 10,135	$ 9,900	$ 3,994	$ 4,793	$ 17,365	$ 14,511	$ 9,443	$ -
				0.0%	*3.0%*	*2.9%*	*1.2%*	*1.4%*	*5.2%*	*4.3%*	*2.8%*	*0.0%*

Operating Assumptions

Data Inputs																	
Plant Name			Limerick 1		Limerick 2		Muddy Run		P. Bottom 2		P. Bottom 3		Salem 1		Salem 2		Schuylkill		C. Turbines
Capacity (MW)			2,170				880		929				942				166		822
Case Description:																			
Plant Type			Nuc		Nuc		Water		Nuc		Nuc		Nuc		Nuc		Oil		Oil
Decommissioning:																			
Decommissioning Year - Adjusted			2024		2029		2029		2013		2014		2016		2020		1999		2014
Decommissioning Year - Nameplate			2024		2029		2014		2013		2014		2016		2020		1999		1999
Life Extension Years			0		0		15		0		0		0		0		0		15
Required Life Extension Costs	1997	$	-	$	-	$	20,000	$	-	$	-	$	-	$	-	$	-	$	20,000
Decommissioning Exp.	Flat	$	3,116	$	5,138	$	-	$	5,413	$	5,407	$	2,626	$	1,939	$	-	$	-
O&M Buildup:																			
Fixed Charge - $000	1997	$	79,053	$	79,053	$	7,639	$	35,711	$	35,711	$	63,194	$	63,194	$	2,713	$	9,131
Incremental Charge - $/MWhr	1997	$	-	$	-	$	0.45	$	-	$	-	$	-	$	-	$	0.43	$	2.22
NOX 1999-2002 $/MWhr	1997	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	1,080
NOX 2003&Thereafter $/MWhr	1997	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	0.31	$	1,960
Merrill Creek	Flat	$	8,200	$	8,200	$	-	$	-	$	-	$	-	$	-	$	-	$	-
1997 Operating & Maintenance - Base		$	87,253	$	87,253	$	8,156	$	35,711	$	35,711	$	63,194	$	63,194	$	2,715	$	9,131
1996 Operating & Maintenance -Estimate		$	96,815	$	68,700	$	6,164	$	46,458	$	23,357	$	84,490	$	93,287	$	7,000	$	-
1995 Operating & Maintenance - Actual		$	76,315	$	91,630	$	4,708	$	28,435	$	47,823	$	73,035	$	58,183	$	2,910	$	3,657
1994 Operating & Maintenance - Actual		$	98,434	$	74,749	$	4,870	$	53,885	$	25,631	$	60,924	$	55,692	$	6,075	$	-
Capital Expenditures:			**		**														
1997 Capital Expenditures Base		$	22,736	$	22,736	$	1,100	$	7,542	$	7,542	$	7,542	$	7,542	$	800	$	900
1996 Capital Expenditures Estimate		$	19,119	$	7,707	$	12,067	$	8,108	$	5,130	$	75,015	$	47,698	$	47	$	989
1995 Capital Expenditures Actual		$	16,445	$	23,350	$	3,930	$	9,449	$	12,511	$	30,773	$	29,433	$	84	$	262
1994 Capital Expenditures Actual		$	22,183	$	23,474	$	3,830	$	23,061	$	5,891	$	20,218	$	20,800	$	1,509	$	-
		** includes Carrying Charges on Limerick fuel inventory																	
Other Costs:																			
Admin & General Exp.	1995	$	15,247	$	15,247	$	1,425	$	6,240	$	6,240	$	-	$	-	$	474	$	1,596
Other Taxes	1995	$	27,244	$	27,244	$	2,547	$	11,151	$	11,151	$	-	$	-	$	848	$	2,851
Allocation Factors:																			
1997 O&M ex Salem,Keystone&Conemaugh		$	87,253	$	87,253	$	8,156	$	35,711	$	35,711	$	-	$	-	$	2,715	$	9,131
			26.0%		*26.0%*		*2.4%*		*10.6%*		*10.6%*		*0.0%*		*0.0%*		*0.8%*		*2.7%*

General and Growth Assumptions

General Assumption	
Discount Rate	8.88%
Income Tax Rate	41.493%

Growth Assumptions

Year	Annual GDP Deflator	Cumulative GDP Deflator
1995	1.0000	1.0000
1996	1.0200	1.0200
1997	1.0196	1.0400
1998	1.0288	1.0700
1999	1.0187	1.0900
2000	1.0275	1.1200
2001	1.0268	1.1500
2002	1.0348	1.1900
2003	1.0252	1.2200
2004	1.0328	1.2600
2005	1.0317	1.3000
2006	1.0385	1.3500
2007	1.0296	1.3900
2008	1.0360	1.4400
2009	1.0347	1.4900
2010	1.0403	1.5500
2011	1.0323	1.6000
2012	1.0375	1.6600
2013	1.0361	1.7200
2014	1.0349	1.7800
2015	1.0337	1.8400
2016	1.0380	1.9100
2017	1.0366	1.9800
2018	1.0354	2.0500
2019	1.0390	2.1300
2020	1.0376	2.2100
2021	1.0376	2.2930
2022	1.0376	2.3791
2023	1.0376	2.4685
2024	1.0376	2.5612
2025	1.0376	2.6574
2026	1.0376	2.7572
2027	1.0376	2.8608
2028	1.0376	2.9682
2029	1.0376	3.0797

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Generation Projection (MWhrs)										
1999	39,814,854	2,441,720	1,718,476	960,716	250,589	6,431	1,700,420	1,840,598	337,821	2,473,538
2000	40,131,525	2,441,720	1,718,477	975,883	-	-	1,788,518	1,935,959	662,976	2,473,538
2001	40,230,584	2,441,720	1,718,477	993,505	-	-	1,788,518	1,935,959	665,723	2,473,538
2002	40,329,643	2,441,720	1,718,477	1,011,126	-	-	1,788,518	1,935,959	668,469	2,473,538
2003	40,421,463	2,441,720	1,718,477	1,022,887	-	-	1,822,242	1,972,463	668,469	2,473,538
2004	40,513,284	2,441,720	1,718,477	1,034,649	-	-	1,855,965	2,008,966	668,469	2,473,538
2005	39,584,229	2,441,720	1,718,477	-	-	-	1,878,473	2,033,329	668,469	2,473,538
2006	39,689,822	2,441,720	1,718,477	-	-	-	1,900,981	2,057,693	668,469	2,473,538
2007	39,687,312	2,441,720	1,718,477	-	-	-	1,923,489	2,082,056	690,091	2,473,538
2008	39,684,803	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	711,713	2,473,538
2009	39,749,756	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	703,053	2,473,538
2010	39,814,709	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	694,393	2,473,538
2011	39,803,726	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	682,001	2,473,538
2012	39,792,744	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	669,609	2,473,538
2013	39,769,481	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	643,441	2,473,538
2014	36,693,058	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	617,273	2,473,538
2015	33,597,714	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	597,294	2,473,538
2016	33,597,714	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	597,294	2,473,538
2017	30,501,163	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	597,294	2,473,538
2018	30,501,163	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	597,294	2,473,538
2019	28,027,626	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	597,294	-
2020	28,027,626	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	597,294	-
2021	24,931,075	2,441,720	1,718,477	-	-	-	1,945,997	2,106,420	597,294	-
2022	22,489,355	-	1,718,477	-	-	-	1,945,997	2,106,420	597,294	-
2023	22,489,355	-	1,718,477	-	-	-	1,945,997	2,106,420	597,294	-
2024	22,489,355	-	1,718,477	-	-	-	1,945,997	2,106,420	597,294	-
2025	15,224,622	-	1,718,477	-	-	-	1,945,997	2,106,420	597,294	-
2026	10,574,912	-	1,718,477	-	-	-	-	-	-	-
2027	10,574,912	-	1,718,477	-	-	-	-	-	-	-
2028	10,574,912	-	1,718,477	-	-	-	-	-	-	-
2029	10,574,912	-	1,718,477	-	-	-	-	-	-	-

(1) indicates capacity payment

ICF Resources, Inc. - Utilizing Dr. B. Venkat

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Generation Projection (MWhrs)									(1)
1999	7,264,732	7,330,477	1,181,804	3,053,160	3,053,160	3,096,551	3,096,551	8,108	1
2000	7,264,732	7,330,477	1,237,664	3,053,160	3,053,160	3,096,551	3,096,551	-	2,159
2001	7,264,732	7,330,477	1,315,228	3,053,160	3,053,160	3,096,551	3,096,551	-	3,286
2002	7,264,732	7,330,477	1,392,792	3,053,160	3,053,160	3,096,551	3,096,551	-	4,412
2003	7,264,732	7,330,477	1,401,101	3,053,160	3,053,160	3,096,551	3,096,551	-	5,936
2004	7,264,732	7,330,477	1,409,410	3,053,160	3,053,160	3,096,551	3,096,551	-	7,459
2005	7,264,732	7,330,477	1,467,684	3,053,160	3,053,160	3,096,551	3,096,551	-	7,907
2006	7,264,732	7,330,477	1,525,958	3,053,160	3,053,160	3,096,551	3,096,551	-	8,355
2007	7,264,732	7,330,477	1,453,672	3,053,160	3,053,160	3,096,551	3,096,551	-	9,639
2008	7,264,732	7,330,477	1,381,385	3,053,160	3,053,160	3,096,551	3,096,551	-	10,923
2009	7,264,732	7,330,477	1,453,672	3,053,160	3,053,160	3,096,551	3,096,551	-	12,249
2010	7,264,732	7,330,477	1,525,958	3,053,160	3,053,160	3,096,551	3,096,551	-	13,575
2011	7,264,732	7,330,477	1,525,958	3,053,160	3,053,160	3,096,551	3,096,551	-	14,984
2012	7,264,732	7,330,477	1,525,958	3,053,160	3,053,160	3,096,551	3,096,551	-	16,394
2013	7,264,732	7,330,477	1,525,958	3,053,160	3,053,160	3,096,551	3,096,551	-	19,299
2014	7,264,732	7,330,477	1,525,958	-	3,053,160	3,096,551	3,096,551	-	22,205
2015	7,264,732	7,330,477	1,525,958	-	-	3,096,551	3,096,551	-	-
2016	7,264,732	7,330,477	1,525,958	-	-	3,096,551	3,096,551	-	-
2017	7,264,732	7,330,477	1,525,958	-	-	-	3,096,551	-	-
2018	7,264,732	7,330,477	1,525,958	-	-	-	3,096,551	-	-
2019	7,264,732	7,330,477	1,525,958	-	-	-	3,096,551	-	-
2020	7,264,732	7,330,477	1,525,958	-	-	-	3,096,551	-	-
2021	7,264,732	7,330,477	1,525,958	-	-	-	-	-	-
2022	7,264,732	7,330,477	1,525,958	-	-	-	-	-	-
2023	7,264,732	7,330,477	1,525,958	-	-	-	-	-	-
2024	7,264,732	7,330,477	1,525,958	-	-	-	-	-	-
2025	-	7,330,477	1,525,958	-	-	-	-	-	-
2026	-	7,330,477	1,525,958	-	-	-	-	-	-
2027	-	7,330,477	1,525,958	-	-	-	-	-	-
2028	-	7,330,477	1,525,958	-	-	-	-	-	-
2029	-	7,330,477	1,525,958	-	-	-	-	-	-

(1) indicates capacity payment

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Market Price Rate ($/MWhr)										
Energy & Capacity										
1999	$ 27.71	$ 24.50	$ 33.62	$ 26.55	$ 45.53	$ 875.36	$ 27.03	$ 27.03	$ 79.58	$ 24.50
2000	$ 29.91	$ 26.77	$ 36.77	$ 28.72	$ -	$ -	$ 28.93	$ 28.93	$ 61.15	$ 26.77
2001	$ 32.39	$ 28.75	$ 40.19	$ 30.52	$ -	$ -	$ 31.00	$ 31.00	$ 70.86	$ 28.75
2002	$ 36.63	$ 32.00	$ 46.05	$ 33.53	$ -	$ -	$ 34.43	$ 34.43	$ 89.05	$ 32.00
2003	$ 37.74	$ 33.04	$ 47.53	$ 34.43	$ -	$ -	$ 35.25	$ 35.25	$ 91.63	$ 33.04
2004	$ 39.18	$ 34.35	$ 49.40	$ 35.62	$ -	$ -	$ 36.35	$ 36.35	$ 94.99	$ 34.35
2005	$ 41.02	$ 35.93	$ 51.83	$ -	$ -	$ -	$ 37.81	$ 37.81	$ 99.62	$ 35.93
2006	$ 43.11	$ 37.83	$ 54.72	$ -	$ -	$ -	$ 39.57	$ 39.57	$ 105.13	$ 37.83
2007	$ 44.87	$ 39.44	$ 56.97	$ -	$ -	$ -	$ 41.01	$ 41.01	$ 106.93	$ 39.44
2008	$ 46.97	$ 41.36	$ 59.66	$ -	$ -	$ -	$ 42.75	$ 42.75	$ 109.53	$ 41.36
2009	$ 48.91	$ 43.08	$ 62.15	$ -	$ -	$ -	$ 44.53	$ 44.53	$ 114.64	$ 43.08
2010	$ 51.19	$ 45.12	$ 65.09	$ -	$ -	$ -	$ 46.62	$ 46.62	$ 120.63	$ 45.12
2011	$ 52.96	$ 46.68	$ 67.34	$ -	$ -	$ -	$ 48.23	$ 48.23	$ 126.23	$ 46.68
2012	$ 55.06	$ 48.53	$ 70.03	$ -	$ -	$ -	$ 50.14	$ 50.14	$ 132.79	$ 48.53
2013	$ 57.21	$ 50.42	$ 72.78	$ -	$ -	$ -	$ 52.09	$ 52.09	$ 141.55	$ 50.42
2014	$ 59.93	$ 52.32	$ 75.56	$ -	$ -	$ -	$ 54.05	$ 54.05	$ 150.85	$ 52.32
2015	$ 61.17	$ 54.38	$ 78.44	$ -	$ -	$ -	$ 56.16	$ 56.16	$ 159.77	$ 54.38
2016	$ 63.49	$ 56.45	$ 81.42	$ -	$ -	$ -	$ 58.29	$ 58.29	$ 165.85	$ 56.45
2017	$ 66.32	$ 58.52	$ 84.40	$ -	$ -	$ -	$ 60.43	$ 60.43	$ 171.93	$ 58.52
2018	$ 68.67	$ 60.59	$ 87.39	$ -	$ -	$ -	$ 62.57	$ 62.57	$ 178.01	$ 60.59
2019	$ 72.09	$ 62.96	$ 90.80	$ -	$ -	$ -	$ 65.01	$ 65.01	$ 184.95	$ -
2020	$ 74.80	$ 65.32	$ 94.21	$ -	$ -	$ -	$ 67.45	$ 67.45	$ 191.90	$ -
2021	$ 78.49	$ 67.77	$ 97.75	$ -	$ -	$ -	$ 69.98	$ 69.98	$ 199.11	$ -
2022	$ 82.65	$ -	$ 101.42	$ -	$ -	$ -	$ 72.61	$ 72.61	$ 206.58	$ -
2023	$ 85.75	$ -	$ 105.23	$ -	$ -	$ -	$ 75.34	$ 75.34	$ 214.34	$ -
2024	$ 88.98	$ -	$ 109.18	$ -	$ -	$ -	$ 78.17	$ 78.17	$ 222.39	$ -
2025	$ 97.40	$ -	$ 113.28	$ -	$ -	$ -	$ 81.10	$ 81.10	$ 230.75	$ -
2026	$ 99.73	$ -	$ 117.53	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 103.47	$ -	$ 121.95	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 107.36	$ -	$ 126.53	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 111.39	$ -	$ 131.28	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(1) ### indicates capacity payment not rate

ICF Resources, Inc. - Utilizing Dr. B. Venkat

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Market Price Rate ($/MWhr)									
Energy & Capacity									(1)
1999	$ 25.84	$ 25.84	$ 43.42	$ 24.61	$ 24.61	$ 25.84	$ 25.84	$ 478.94	###########
2000	$ 28.17	$ 28.17	$ 47.72	$ 26.91	$ 26.91	$ 28.17	$ 28.17	$ -	$ 9,496.26
2001	$ 30.16	$ 30.16	$ 53.06	$ 28.95	$ 28.95	$ 30.16	$ 30.16	$ -	$ 8,008.17
2002	$ 33.49	$ 33.49	$ 62.86	$ 32.31	$ 32.31	$ 33.49	$ 33.49	$ -	$ 8,598.20
2003	$ 34.56	$ 34.56	$ 64.51	$ 33.34	$ 33.34	$ 34.56	$ 34.56	$ -	$ 6,572.73
2004	$ 35.92	$ 35.92	$ 66.70	$ 34.67	$ 34.67	$ 35.92	$ 35.92	$ -	$ 5,418.68
2005	$ 37.52	$ 37.52	$ 68.44	$ 36.24	$ 36.24	$ 37.52	$ 37.52	$ -	$ 5,279.42
2006	$ 39.45	$ 39.45	$ 70.79	$ 38.12	$ 38.12	$ 39.45	$ 39.45	$ -	$ 5,193.94
2007	$ 41.08	$ 41.08	$ 75.29	$ 39.72	$ 39.72	$ 41.08	$ 41.08	$ -	$ 4,648.08
2008	$ 43.04	$ 43.04	$ 80.66	$ 41.63	$ 41.63	$ 43.04	$ 43.04	$ -	$ 4,261.00
2009	$ 44.83	$ 44.83	$ 81.97	$ 43.37	$ 43.37	$ 44.84	$ 44.84	$ -	$ 3,942.96
2010	$ 46.95	$ 46.95	$ 83.89	$ 45.43	$ 45.43	$ 46.95	$ 46.95	$ -	$ 3,711.83
2011	$ 48.56	$ 48.56	$ 86.93	$ 46.99	$ 46.99	$ 48.56	$ 48.56	$ -	$ 3,481.96
2012	$ 50.48	$ 50.48	$ 90.53	$ 48.84	$ 48.84	$ 50.48	$ 50.48	$ -	$ 3,312.34
2013	$ 52.45	$ 52.45	$ 94.05	$ 50.75	$ 50.75	$ 52.45	$ 52.45	$ -	$ 2,933.85
2014	$ 54.42	$ 54.42	$ 97.59	$ -	$ 52.67	$ 54.42	$ 54.42	$ -	$ 2,655.83
2015	$ 56.54	$ 56.54	$ 101.25	$ -	$ -	$ 56.54	$ 56.54	$ -	$ -
2016	$ 58.69	$ 58.69	$ 105.10	$ -	$ -	$ 58.69	$ 58.69	$ -	$ -
2017	$ 60.84	$ 60.84	$ 108.95	$ -	$ -	$ -	$ 60.85	$ -	$ -
2018	$ 63.00	$ 63.00	$ 112.80	$ -	$ -	$ -	$ 63.00	$ -	$ -
2019	$ 65.45	$ 65.45	$ 117.20	$ -	$ -	$ -	$ 65.46	$ -	$ -
2020	$ 67.91	$ 67.91	$ 121.61	$ -	$ -	$ -	$ 67.91	$ -	$ -
2021	$ 70.46	$ 70.46	$ 126.17	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 73.11	$ 73.11	$ 130.91	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 75.86	$ 75.86	$ 135.83	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 78.70	$ 78.70	$ 140.93	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 81.66	$ 146.22	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 84.73	$ 151.72	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 87.91	$ 157.41	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 91.21	$ 163.33	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 94.64	$ 169.46	$ -	$ -	$ -	$ -	$ -	$ -

(1) ### indicates capacity payment not rate

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Market Price Revenues	*(generation x market rate) (000's)*									
Energy & Capacity										
1999	$ 1,103,252	$ 59,813	$ 57,771	$ 25,505	$ 11,410	$ 5,629	$ 45,965	$ 49,754	$ 26,885	$ 60,593
2000	$ 1,200,515	$ 65,363	$ 63,180	$ 28,031	$ -	$ -	$ 51,748	$ 56,014	$ 40,539	$ 66,214
2001	$ 1,303,231	$ 70,202	$ 69,062	$ 30,318	$ -	$ -	$ 55,445	$ 60,015	$ 47,175	$ 71,117
2002	$ 1,477,144	$ 78,142	$ 79,144	$ 33,908	$ -	$ -	$ 61,587	$ 66,664	$ 59,529	$ 79,160
2003	$ 1,525,674	$ 80,663	$ 81,671	$ 35,220	$ -	$ -	$ 64,232	$ 69,527	$ 61,254	$ 81,714
2004	$ 1,587,380	$ 83,877	$ 84,899	$ 36,849	$ -	$ -	$ 67,472	$ 73,034	$ 63,495	$ 84,970
2005	$ 1,623,686	$ 87,741	$ 89,070	$ -	$ -	$ -	$ 71,017	$ 76,872	$ 66,592	$ 88,884
2006	$ 1,711,134	$ 92,363	$ 94,029	$ -	$ -	$ -	$ 75,225	$ 81,426	$ 70,276	$ 93,566
2007	$ 1,780,602	$ 96,290	$ 97,893	$ -	$ -	$ -	$ 78,873	$ 85,375	$ 73,790	$ 97,545
2008	$ 1,864,034	$ 100,988	$ 102,532	$ -	$ -	$ -	$ 83,197	$ 90,055	$ 77,955	$ 102,304
2009	$ 1,943,975	$ 105,199	$ 106,810	$ -	$ -	$ -	$ 86,652	$ 93,795	$ 80,597	$ 106,569
2010	$ 2,038,133	$ 110,167	$ 111,858	$ -	$ -	$ -	$ 90,730	$ 98,209	$ 83,766	$ 111,603
2011	$ 2,107,920	$ 113,969	$ 115,727	$ -	$ -	$ -	$ 93,856	$ 101,593	$ 86,092	$ 115,454
2012	$ 2,191,149	$ 118,501	$ 120,338	$ -	$ -	$ -	$ 97,582	$ 105,626	$ 88,919	$ 120,045
2013	$ 2,275,388	$ 123,116	$ 125,078	$ -	$ -	$ -	$ 101,368	$ 109,724	$ 91,077	$ 124,720
2014	$ 2,199,138	$ 127,755	$ 129,846	$ -	$ -	$ -	$ 105,172	$ 113,842	$ 93,116	$ 129,420
2015	$ 2,055,035	$ 132,790	$ 134,790	$ -	$ -	$ -	$ 109,281	$ 118,289	$ 95,430	$ 134,521
2016	$ 2,133,215	$ 137,842	$ 139,918	$ -	$ -	$ -	$ 113,438	$ 122,790	$ 99,061	$ 139,639
2017	$ 2,022,983	$ 142,894	$ 145,046	$ -	$ -	$ -	$ 117,595	$ 127,290	$ 102,691	$ 144,756
2018	$ 2,094,503	$ 147,946	$ 150,174	$ -	$ -	$ -	$ 121,753	$ 131,790	$ 106,322	$ 149,874
2019	$ 2,020,517	$ 153,719	$ 156,034	$ -	$ -	$ -	$ 126,504	$ 136,933	$ 110,471	$ -
2020	$ 2,096,405	$ 159,493	$ 161,894	$ -	$ -	$ -	$ 131,256	$ 142,076	$ 114,620	$ -
2021	$ 1,956,945	$ 165,483	$ 167,975	$ -	$ -	$ -	$ 136,185	$ 147,412	$ 118,925	$ -
2022	$ 1,858,747	$ -	$ 174,284	$ -	$ -	$ -	$ 141,300	$ 152,949	$ 123,392	$ -
2023	$ 1,928,559	$ -	$ 180,830	$ -	$ -	$ -	$ 146,607	$ 158,693	$ 128,026	$ -
2024	$ 2,000,993	$ -	$ 187,621	$ -	$ -	$ -	$ 152,114	$ 164,654	$ 132,835	$ -
2025	$ 1,482,903	$ -	$ 194,668	$ -	$ -	$ -	$ 157,827	$ 170,838	$ 137,824	$ -
2026	$ 1,054,590	$ -	$ 201,980	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 1,094,199	$ -	$ 209,566	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 1,135,295	$ -	$ 217,437	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 1,177,936	$ -	$ 225,604	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkat

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Market Price Revenues									
Energy & Capacity									
1999	$ 187,707	$ 189,406	$ 51,310	$ 75,145	$ 75,145	$ 80,010	$ 80,010	$ 3,883	$ 17,312
2000	$ 204,622	$ 206,474	$ 59,067	$ 82,160	$ 82,160	$ 87,220	$ 87,220	$ -	$ 20,503
2001	$ 219,128	$ 221,111	$ 69,784	$ 88,377	$ 88,377	$ 93,404	$ 93,404	$ -	$ 26,312
2002	$ 243,308	$ 245,510	$ 87,549	$ 98,642	$ 98,642	$ 103,711	$ 103,711	$ -	$ 37,938
2003	$ 251,047	$ 253,319	$ 90,386	$ 101,805	$ 101,805	$ 107,009	$ 107,009	$ -	$ 39,014
2004	$ 260,935	$ 263,297	$ 94,004	$ 105,840	$ 105,840	$ 111,224	$ 111,224	$ -	$ 40,419
2005	$ 272,588	$ 275,055	$ 100,455	$ 110,643	$ 110,643	$ 116,191	$ 116,191	$ -	$ 41,744
2006	$ 286,570	$ 289,163	$ 108,026	$ 116,397	$ 116,397	$ 122,151	$ 122,151	$ -	$ 43,393
2007	$ 298,453	$ 301,154	$ 109,453	$ 121,271	$ 121,271	$ 127,216	$ 127,216	$ -	$ 44,802
2008	$ 312,702	$ 315,532	$ 111,427	$ 127,110	$ 127,110	$ 133,290	$ 133,290	$ -	$ 46,542
2009	$ 325,713	$ 328,661	$ 119,153	$ 132,429	$ 132,429	$ 138,836	$ 138,836	$ -	$ 48,296
2010	$ 341,070	$ 344,156	$ 128,017	$ 138,703	$ 138,703	$ 145,382	$ 145,382	$ -	$ 50,387
2011	$ 352,777	$ 355,969	$ 132,650	$ 143,457	$ 143,457	$ 150,372	$ 150,372	$ -	$ 52,174
2012	$ 366,737	$ 370,056	$ 138,147	$ 149,127	$ 149,127	$ 156,322	$ 156,322	$ -	$ 54,301
2013	$ 381,005	$ 384,453	$ 143,516	$ 154,949	$ 154,949	$ 162,404	$ 162,404	$ -	$ 56,622
2014	$ 395,345	$ 398,923	$ 148,912	$ -	$ 160,801	$ 168,517	$ 168,517	$ -	$ 58,974
2015	$ 410,768	$ 414,485	$ 154,499	$ -	$ -	$ 175,091	$ 175,091	$ -	$ -
2016	$ 426,395	$ 430,254	$ 160,376	$ -	$ -	$ 181,752	$ 181,752	$ -	$ -
2017	$ 442,022	$ 446,022	$ 166,254	$ -	$ -	$ -	$ 188,413	$ -	$ -
2018	$ 457,649	$ 461,791	$ 172,132	$ -	$ -	$ -	$ 195,074	$ -	$ -
2019	$ 475,508	$ 479,812	$ 178,849	$ -	$ -	$ -	$ 202,687	$ -	$ -
2020	$ 493,368	$ 497,833	$ 185,566	$ -	$ -	$ -	$ 210,299	$ -	$ -
2021	$ 511,898	$ 516,531	$ 192,536	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 531,124	$ 535,931	$ 199,767	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 551,073	$ 556,060	$ 207,270	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 571,770	$ 576,945	$ 215,055	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 598,614	$ 223,132	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 621,097	$ 231,513	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 644,425	$ 240,208	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 668,628	$ 249,230	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 693,741	$ 258,591	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Fuel Rate ($/MWhr)										
1999	$ 7.60	$ 9.98	$ -	$ 15.88	$ 24.34	$ 38.77	$ 16.64	$ 16.64	$ 26.25	$ 9.80
2000	$ 7.99	$ 10.19	$ -	$ 16.67	$ -	$ -	$ 17.24	$ 17.24	$ 27.36	$ 12.26
2001	$ 8.08	$ 10.22	$ -	$ 16.73	$ -	$ -	$ 17.31	$ 17.31	$ 28.48	$ 12.34
2002	$ 8.25	$ 10.31	$ -	$ 16.92	$ -	$ -	$ 17.50	$ 17.50	$ 29.88	$ 12.52
2003	$ 8.42	$ 10.36	$ -	$ 17.14	$ -	$ -	$ 17.66	$ 17.66	$ 31.08	$ 13.13
2004	$ 8.64	$ 10.49	$ -	$ 17.47	$ -	$ -	$ 17.96	$ 17.96	$ 32.56	$ 13.86
2005	$ 8.64	$ 10.63	$ -	$ -	$ -	$ -	$ 18.20	$ 18.20	$ 34.08	$ 14.12
2006	$ 8.97	$ 10.84	$ -	$ -	$ -	$ -	$ 18.56	$ 18.56	$ 35.90	$ 14.47
2007	$ 9.29	$ 11.09	$ -	$ -	$ -	$ -	$ 19.01	$ 19.01	$ 37.68	$ 15.48
2008	$ 9.66	$ 11.42	$ -	$ -	$ -	$ -	$ 19.59	$ 19.59	$ 39.79	$ 16.63
2009	$ 10.02	$ 11.69	$ -	$ -	$ -	$ -	$ 20.00	$ 20.00	$ 41.69	$ 17.09
2010	$ 10.46	$ 12.03	$ -	$ -	$ -	$ -	$ 20.52	$ 20.52	$ 43.92	$ 17.65
2011	$ 10.76	$ 12.29	$ -	$ -	$ -	$ -	$ 20.99	$ 20.99	$ 45.58	$ 18.09
2012	$ 11.14	$ 12.61	$ -	$ -	$ -	$ -	$ 21.57	$ 21.57	$ 47.55	$ 18.65
2013	$ 11.59	$ 13.01	$ -	$ -	$ -	$ -	$ 22.34	$ 22.34	$ 49.54	$ 20.13
2014	$ 12.36	$ 13.41	$ -	$ -	$ -	$ -	$ 23.12	$ 23.12	$ 51.56	$ 21.68
2015	$ 13.04	$ 13.72	$ -	$ -	$ -	$ -	$ 23.66	$ 23.66	$ 53.64	$ 22.27
2016	$ 13.54	$ 14.24	$ -	$ -	$ -	$ -	$ 24.56	$ 24.56	$ 55.68	$ 23.12
2017	$ 14.54	$ 14.76	$ -	$ -	$ -	$ -	$ 25.46	$ 25.46	$ 57.72	$ 23.97
2018	$ 15.05	$ 15.28	$ -	$ -	$ -	$ -	$ 26.36	$ 26.36	$ 59.77	$ 24.82
2019	$ 14.75	$ 15.88	$ -	$ -	$ -	$ -	$ 27.39	$ 27.39	$ 62.10	$ -
2020	$ 15.30	$ 16.48	$ -	$ -	$ -	$ -	$ 28.42	$ 28.42	$ 64.43	$ -
2021	$ 16.54	$ 17.10	$ -	$ -	$ -	$ -	$ 29.49	$ 29.49	$ 66.85	$ -
2022	$ 17.10	$ -	$ -	$ -	$ -	$ -	$ 30.60	$ 30.60	$ 69.36	$ -
2023	$ 17.74	$ -	$ -	$ -	$ -	$ -	$ 31.74	$ 31.74	$ 71.97	$ -
2024	$ 18.40	$ -	$ -	$ -	$ -	$ -	$ 32.94	$ 32.94	$ 74.67	$ -
2025	$ 23.57	$ -	$ -	$ -	$ -	$ -	$ 34.17	$ 34.17	$ 77.47	$ -
2026	$ 17.09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 17.73	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 18.39	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 19.09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkat

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Fuel Rate ($/MWhr)									
1999	$ 4.46	$ 4.46	$ 23.25	$ 5.84	$ 5.84	$ 5.84	$ 5.84	$ 36.33	$ -
2000	$ 4.42	$ 4.42	$ 25.66	$ 5.74	$ 5.74	$ 5.74	$ 5.74	$ -	$ 67.09
2001	$ 4.43	$ 4.43	$ 26.43	$ 5.68	$ 5.68	$ 5.68	$ 5.68	$ -	$ 69.47
2002	$ 4.50	$ 4.50	$ 27.43	$ 5.72	$ 5.72	$ 5.72	$ 5.72	$ -	$ 72.49
2003	$ 4.55	$ 4.55	$ 28.29	$ 5.75	$ 5.75	$ 5.75	$ 5.75	$ -	$ 75.03
2004	$ 4.60	$ 4.60	$ 29.39	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ -	$ 78.24
2005	$ 4.68	$ 4.68	$ 30.52	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ -	$ 81.38
2006	$ 4.87	$ 4.87	$ 31.89	$ 6.17	$ 6.17	$ 6.17	$ 6.17	$ -	$ 85.19
2007	$ 5.06	$ 5.06	$ 33.02	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ -	$ 88.55
2008	$ 5.26	$ 5.26	$ 34.40	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ -	$ 92.60
2009	$ 5.44	$ 5.44	$ 36.12	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ -	$ 96.56
2010	$ 5.66	$ 5.66	$ 38.12	$ 7.12	$ 7.12	$ 7.12	$ 7.12	$ -	$ 101.22
2011	$ 5.84	$ 5.84	$ 39.53	$ 7.35	$ 7.35	$ 7.35	$ 7.35	$ -	$ 105.33
2012	$ 6.06	$ 6.06	$ 41.20	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ -	$ 110.14
2013	$ 6.28	$ 6.28	$ 43.03	$ 7.90	$ 7.90	$ 7.90	$ 7.90	$ -	$ 115.22
2014	$ 6.50	$ 6.50	$ 44.89	$ -	$ 8.17	$ 8.17	$ 8.17	$ -	$ 120.37
2015	$ 6.72	$ 6.72	$ 46.74	$ -	$ -	$ 8.45	$ 8.45	$ -	$ -
2016	$ 6.98	$ 6.98	$ 48.51	$ -	$ -	$ 8.77	$ 8.77	$ -	$ -
2017	$ 7.23	$ 7.23	$ 50.29	$ -	$ -	$ -	$ 9.09	$ -	$ -
2018	$ 7.49	$ 7.49	$ 52.07	$ -	$ -	$ -	$ 9.41	$ -	$ -
2019	$ 7.78	$ 7.78	$ 54.10	$ -	$ -	$ -	$ 9.78	$ -	$ -
2020	$ 8.07	$ 8.07	$ 56.13	$ -	$ -	$ -	$ 10.15	$ -	$ -
2021	$ 8.38	$ 8.38	$ 58.24	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 8.69	$ 8.69	$ 60.43	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 9.02	$ 9.02	$ 62.70	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 9.36	$ 9.36	$ 65.05	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 9.71	$ 67.50	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 10.07	$ 70.03	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 10.45	$ 72.66	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 10.84	$ 75.39	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 11.25	$ 78.22	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)

Fuel Cost	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
	(generation x fuel rate) (000's)									
1999	$ 302,582	$ 24,377	$ -	$ 15,259	$ 6,100	$ 249	$ 28,291	$ 30,623	$ 8,867	$ 24,228
2000	$ 320,791	$ 24,891	$ -	$ 16,264	$ -	$ -	$ 30,835	$ 33,377	$ 18,137	$ 30,316
2001	$ 324,995	$ 24,944	$ -	$ 16,625	$ -	$ -	$ 30,952	$ 33,503	$ 18,961	$ 30,523
2002	$ 332,885	$ 25,177	$ -	$ 17,113	$ -	$ -	$ 31,295	$ 33,875	$ 19,973	$ 30,959
2003	$ 340,364	$ 25,306	$ -	$ 17,528	$ -	$ -	$ 32,189	$ 34,842	$ 20,774	$ 32,473
2004	$ 350,057	$ 25,614	$ -	$ 18,080	$ -	$ -	$ 33,333	$ 36,081	$ 21,763	$ 34,295
2005	$ 341,821	$ 25,960	$ -	$ -	$ -	$ -	$ 34,191	$ 37,009	$ 22,780	$ 34,924
2006	$ 356,008	$ 26,474	$ -	$ -	$ -	$ -	$ 35,262	$ 38,190	$ 23,995	$ 35,789
2007	$ 368,733	$ 27,085	$ -	$ -	$ -	$ -	$ 36,567	$ 39,582	$ 26,005	$ 38,279
2008	$ 383,374	$ 27,880	$ -	$ -	$ -	$ -	$ 38,127	$ 41,270	$ 28,319	$ 41,136
2009	$ 398,449	$ 28,538	$ -	$ -	$ -	$ -	$ 38,921	$ 42,129	$ 29,313	$ 42,263
2010	$ 416,400	$ 29,365	$ -	$ -	$ -	$ -	$ 39,936	$ 43,229	$ 30,495	$ 43,651
2011	$ 428,460	$ 29,998	$ -	$ -	$ -	$ -	$ 40,840	$ 44,207	$ 31,087	$ 44,756
2012	$ 443,100	$ 30,797	$ -	$ -	$ -	$ -	$ 41,972	$ 45,433	$ 31,840	$ 46,121
2013	$ 460,735	$ 31,770	$ -	$ -	$ -	$ -	$ 43,481	$ 47,066	$ 31,879	$ 49,798
2014	$ 453,518	$ 32,733	$ -	$ -	$ -	$ -	$ 44,990	$ 48,698	$ 31,826	$ 53,616
2015	$ 438,268	$ 33,498	$ -	$ -	$ -	$ -	$ 46,046	$ 49,842	$ 32,041	$ 55,098
2016	$ 454,941	$ 34,772	$ -	$ -	$ -	$ -	$ 47,798	$ 51,738	$ 33,260	$ 57,194
2017	$ 443,458	$ 36,046	$ -	$ -	$ -	$ -	$ 49,550	$ 53,635	$ 34,479	$ 59,290
2018	$ 459,135	$ 37,321	$ -	$ -	$ -	$ -	$ 51,302	$ 55,531	$ 35,698	$ 61,386
2019	$ 413,271	$ 38,777	$ -	$ -	$ -	$ -	$ 53,304	$ 57,698	$ 37,091	$ -
2020	$ 428,793	$ 40,233	$ -	$ -	$ -	$ -	$ 55,306	$ 59,865	$ 38,484	$ -
2021	$ 412,291	$ 41,745	$ -	$ -	$ -	$ -	$ 57,383	$ 62,113	$ 39,929	$ -
2022	$ 384,463	$ -	$ -	$ -	$ -	$ -	$ 59,538	$ 64,446	$ 41,429	$ -
2023	$ 398,903	$ -	$ -	$ -	$ -	$ -	$ 61,774	$ 66,867	$ 42,985	$ -
2024	$ 413,885	$ -	$ -	$ -	$ -	$ -	$ 64,094	$ 69,378	$ 44,599	$ -
2025	$ 358,913	$ -	$ -	$ -	$ -	$ -	$ 66,502	$ 71,984	$ 46,274	$ -
2026	$ 180,694	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 187,480	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 194,522	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 201,828	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkat

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Fuel Cost									
1999	$ 32,379	$ 32,672	$ 27,476	$ 17,815	$ 17,815	$ 18,068	$ 18,068	$ 295	$ -
2000	$ 32,103	$ 32,393	$ 31,756	$ 17,519	$ 17,519	$ 17,768	$ 17,768	$ -	$ 145
2001	$ 32,205	$ 32,496	$ 34,758	$ 17,327	$ 17,327	$ 17,573	$ 17,573	$ -	$ 228
2002	$ 32,684	$ 32,980	$ 38,207	$ 17,452	$ 17,452	$ 17,700	$ 17,700	$ -	$ 320
2003	$ 33,055	$ 33,354	$ 39,640	$ 17,565	$ 17,565	$ 17,814	$ 17,814	$ -	$ 445
2004	$ 33,418	$ 33,720	$ 41,427	$ 17,809	$ 17,809	$ 18,062	$ 18,062	$ -	$ 584
2005	$ 33,999	$ 34,307	$ 44,789	$ 18,175	$ 18,175	$ 18,434	$ 18,434	$ -	$ 643
2006	$ 35,379	$ 35,699	$ 48,660	$ 18,823	$ 18,823	$ 19,090	$ 19,090	$ -	$ 712
2007	$ 36,760	$ 37,092	$ 48,001	$ 19,488	$ 19,488	$ 19,765	$ 19,765	$ -	$ 854
2008	$ 38,212	$ 38,558	$ 47,524	$ 20,191	$ 20,191	$ 20,477	$ 20,477	$ -	$ 1,011
2009	$ 39,539	$ 39,897	$ 52,506	$ 20,892	$ 20,892	$ 21,189	$ 21,189	$ -	$ 1,183
2010	$ 41,132	$ 41,504	$ 58,166	$ 21,733	$ 21,733	$ 22,042	$ 22,042	$ -	$ 1,374
2011	$ 42,458	$ 42,843	$ 60,320	$ 22,434	$ 22,434	$ 22,753	$ 22,753	$ -	$ 1,578
2012	$ 44,051	$ 44,449	$ 62,869	$ 23,275	$ 23,275	$ 23,606	$ 23,606	$ -	$ 1,806
2013	$ 45,643	$ 46,056	$ 65,667	$ 24,116	$ 24,116	$ 24,459	$ 24,459	$ -	$ 2,224
2014	$ 47,235	$ 47,662	$ 68,502	$ -	$ 24,958	$ 25,312	$ 25,312	$ -	$ 2,673
2015	$ 48,827	$ 49,269	$ 71,316	$ -	$ -	$ 26,166	$ 26,166	$ -	$ -
2016	$ 50,685	$ 51,143	$ 74,029	$ -	$ -	$ 27,161	$ 27,161	$ -	$ -
2017	$ 52,542	$ 53,018	$ 76,742	$ -	$ -	$ -	$ 28,157	$ -	$ -
2018	$ 54,400	$ 54,892	$ 79,455	$ -	$ -	$ -	$ 29,152	$ -	$ -
2019	$ 56,523	$ 57,034	$ 82,556	$ -	$ -	$ -	$ 30,290	$ -	$ -
2020	$ 58,646	$ 59,176	$ 85,657	$ -	$ -	$ -	$ 31,427	$ -	$ -
2021	$ 60,848	$ 61,399	$ 88,874	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 63,134	$ 63,705	$ 92,212	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 65,505	$ 66,098	$ 95,675	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 67,965	$ 68,580	$ 99,268	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 71,156	$ 102,997	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 73,828	$ 106,865	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 76,601	$ 110,879	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 79,478	$ 115,044	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 82,464	$ 119,364	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)

Operating & Maintenance Projection

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
1999	$ 508,510	$ 8,047	$ 10,623	$ 11,588	$ 4,536	$ 5,032	$ 20,533	$ 19,497	$ 9,978	$ 7,138
2000	$ 510,799	$ 8,268	$ 10,915	$ 11,980	$ -	$ -	$ 21,545	$ 20,540	$ 10,695	$ 7,335
2001	$ 524,174	$ 8,490	$ 11,207	$ 12,388	$ -	$ -	$ 22,122	$ 21,090	$ 10,985	$ 7,531
2002	$ 541,972	$ 8,785	$ 11,597	$ 12,909	$ -	$ -	$ 22,892	$ 21,823	$ 11,372	$ 7,793
2003	$ 561,638	$ 9,006	$ 11,890	$ 15,012	$ -	$ -	$ 24,553	$ 24,089	$ 12,458	$ 7,990
2004	$ 580,063	$ 9,302	$ 12,280	$ 15,589	$ -	$ -	$ 25,567	$ 25,125	$ 12,867	$ 8,252
2005	$ 582,221	$ 9,597	$ 12,669	$ -	$ -	$ -	$ 26,523	$ 26,093	$ 13,275	$ 8,514
2006	$ 604,344	$ 9,966	$ 13,157	$ -	$ -	$ -	$ 27,693	$ 27,273	$ 13,786	$ 8,841
2007	$ 622,125	$ 10,261	$ 13,546	$ -	$ -	$ -	$ 28,668	$ 28,263	$ 14,260	$ 9,103
2008	$ 644,287	$ 10,630	$ 14,034	$ -	$ -	$ -	$ 29,859	$ 29,467	$ 14,841	$ 9,430
2009	$ 666,109	$ 10,999	$ 14,521	$ -	$ -	$ -	$ 30,896	$ 30,491	$ 15,328	$ 9,758
2010	$ 692,293	$ 11,442	$ 15,106	$ -	$ -	$ -	$ 32,140	$ 31,718	$ 15,916	$ 10,151
2011	$ 714,055	$ 11,812	$ 15,593	$ -	$ -	$ -	$ 33,177	$ 32,742	$ 16,386	$ 10,478
2012	$ 740,173	$ 12,254	$ 16,178	$ -	$ -	$ -	$ 34,421	$ 33,969	$ 16,955	$ 10,871
2013	$ 766,240	$ 12,697	$ 16,763	$ -	$ -	$ -	$ 35,665	$ 35,197	$ 17,469	$ 11,264
2014	$ 731,179	$ 13,140	$ 17,347	$ -	$ -	$ -	$ 36,909	$ 36,425	$ 17,976	$ 11,657
2015	$ 691,960	$ 13,583	$ 17,932	$ -	$ -	$ -	$ 38,154	$ 37,653	$ 18,501	$ 12,050
2016	$ 717,661	$ 14,100	$ 18,614	$ -	$ -	$ -	$ 39,605	$ 39,085	$ 19,205	$ 12,508
2017	$ 623,050	$ 14,617	$ 19,296	$ -	$ -	$ -	$ 41,057	$ 40,518	$ 19,909	$ 12,967
2018	$ 644,497	$ 15,134	$ 19,979	$ -	$ -	$ -	$ 42,508	$ 41,950	$ 20,613	$ 13,425
2019	$ 655,059	$ 15,724	$ 20,758	$ -	$ -	$ -	$ 44,167	$ 43,587	$ 21,417	$ -
2020	$ 679,046	$ 16,315	$ 21,538	$ -	$ -	$ -	$ 45,826	$ 45,224	$ 22,222	$ -
2021	$ 564,603	$ 16,927	$ 22,347	$ -	$ -	$ -	$ 47,547	$ 46,923	$ 23,057	$ -
2022	$ 542,259	$ -	$ 23,186	$ -	$ -	$ -	$ 49,333	$ 48,685	$ 23,923	$ -
2023	$ 562,009	$ -	$ 24,057	$ -	$ -	$ -	$ 51,186	$ 50,514	$ 24,821	$ -
2024	$ 582,501	$ -	$ 24,961	$ -	$ -	$ -	$ 53,108	$ 52,411	$ 25,753	$ -
2025	$ 393,569	$ -	$ 25,898	$ -	$ -	$ -	$ 55,103	$ 54,379	$ 26,721	$ -
2026	$ 266,724	$ -	$ 26,871	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 276,434	$ -	$ 27,880	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 286,508	$ -	$ 28,927	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 296,961	$ -	$ 30,014	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkates
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Operating & Maintenance Projection									
1999	$ 91,054	$ 91,054	$ 8,563	$ 37,428	$ 37,428	$ 66,232	$ 66,232	$ 2,847	$ 10,702
2000	$ 93,334	$ 93,334	$ 8,826	$ 38,458	$ 38,458	$ 68,055	$ 68,055	$ -	$ 11,001
2001	$ 95,614	$ 95,614	$ 9,101	$ 39,488	$ 39,488	$ 69,878	$ 69,878	$ -	$ 11,298
2002	$ 98,655	$ 98,655	$ 9,458	$ 40,862	$ 40,862	$ 72,309	$ 72,309	$ -	$ 11,693
2003	$ 100,935	$ 100,935	$ 9,700	$ 41,892	$ 41,892	$ 74,131	$ 74,131	$ -	$ 13,023
2004	$ 103,976	$ 103,976	$ 10,023	$ 43,265	$ 43,265	$ 76,562	$ 76,562	$ -	$ 13,453
2005	$ 107,016	$ 107,016	$ 10,374	$ 44,639	$ 44,639	$ 78,993	$ 78,993	$ -	$ 13,881
2006	$ 110,817	$ 110,817	$ 10,807	$ 46,356	$ 46,356	$ 82,031	$ 82,031	$ -	$ 14,415
2007	$ 113,857	$ 113,857	$ 11,084	$ 47,729	$ 47,729	$ 84,461	$ 84,461	$ -	$ 14,845
2008	$ 117,658	$ 117,658	$ 11,437	$ 49,446	$ 49,446	$ 87,499	$ 87,499	$ -	$ 15,381
2009	$ 121,459	$ 121,459	$ 11,881	$ 51,163	$ 51,163	$ 90,538	$ 90,538	$ -	$ 15,917
2010	$ 126,019	$ 126,019	$ 12,408	$ 53,223	$ 53,223	$ 94,183	$ 94,183	$ -	$ 16,566
2011	$ 129,820	$ 129,820	$ 12,808	$ 54,940	$ 54,940	$ 97,222	$ 97,222	$ -	$ 17,096
2012	$ 134,381	$ 134,381	$ 13,289	$ 57,000	$ 57,000	$ 100,867	$ 100,867	$ -	$ 17,739
2013	$ 138,942	$ 138,942	$ 13,769	$ 59,061	$ 59,061	$ 104,513	$ 104,513	$ -	$ 18,385
2014	$ 143,502	$ 143,502	$ 14,249	$ -	$ 61,121	$ 108,159	$ 108,159	$ -	$ 19,032
2015	$ 148,063	$ 148,063	$ 14,729	$ -	$ -	$ 111,805	$ 111,805	$ -	$ 19,622
2016	$ 153,384	$ 153,384	$ 15,290	$ -	$ -	$ 116,058	$ 116,058	$ -	$ 20,369
2017	$ 158,705	$ 158,705	$ 15,850	$ -	$ -	$ -	$ 120,312	$ -	$ 21,115
2018	$ 164,026	$ 164,026	$ 16,411	$ -	$ -	$ -	$ 124,565	$ -	$ 21,862
2019	$ 170,107	$ 170,107	$ 17,051	$ -	$ -	$ -	$ 129,426	$ -	$ 22,715
2020	$ 176,188	$ 176,188	$ 17,691	$ -	$ -	$ -	$ 134,287	$ -	$ 23,568
2021	$ 182,497	$ 182,497	$ 18,356	$ -	$ -	$ -	$ -	$ -	$ 24,453
2022	$ 189,043	$ 189,043	$ 19,045	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 195,836	$ 195,836	$ 19,761	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 202,883	$ 202,883	$ 20,503	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 210,195	$ 21,273	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 217,782	$ 22,072	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 225,653	$ 22,901	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 233,821	$ 23,761	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 242,295	$ 24,653	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Capital Expenditure Projection										
1999	$ 98,477	$ 2,054	$ 1,467	$ 1,572	$ 943	$ 1,677	$ 1,887	$ 1,887	$ 1,887	$ 2,893
2000	$ 97,634	$ 2,111	$ 1,508	$ 1,615	$ -	$ -	$ 1,938	$ 1,938	$ 1,938	$ 2,972
2001	$ 100,249	$ 2,167	$ 1,548	$ 1,659	$ -	$ -	$ 1,990	$ 1,990	$ 1,990	$ 3,052
2002	$ 103,736	$ 2,243	$ 1,602	$ 1,716	$ -	$ -	$ 2,060	$ 2,060	$ 2,060	$ 3,158
2003	$ 106,351	$ 2,299	$ 1,642	$ 1,760	$ -	$ -	$ 2,112	$ 2,112	$ 2,112	$ 3,238
2004	$ 109,838	$ 2,375	$ 1,696	$ 1,817	$ -	$ -	$ 2,181	$ 2,181	$ 2,181	$ 3,344
2005	$ 111,450	$ 2,450	$ 1,750	$ -	$ -	$ -	$ 2,250	$ 2,250	$ 2,250	$ 3,450
2006	$ 115,737	$ 2,544	$ 1,817	$ -	$ -	$ -	$ 2,337	$ 2,337	$ 2,337	$ 3,583
2007	$ 119,166	$ 2,620	$ 1,871	$ -	$ -	$ -	$ 2,406	$ 2,406	$ 2,406	$ 3,689
2008	$ 123,452	$ 2,714	$ 1,938	$ -	$ -	$ -	$ 2,492	$ 2,492	$ 2,492	$ 3,822
2009	$ 127,739	$ 2,808	$ 2,006	$ -	$ -	$ -	$ 2,579	$ 2,579	$ 2,579	$ 3,954
2010	$ 132,883	$ 2,921	$ 2,087	$ -	$ -	$ -	$ 2,683	$ 2,683	$ 2,683	$ 4,113
2011	$ 137,169	$ 3,015	$ 2,154	$ -	$ -	$ -	$ 2,769	$ 2,769	$ 2,769	$ 4,246
2012	$ 142,313	$ 3,128	$ 2,235	$ -	$ -	$ -	$ 2,873	$ 2,873	$ 2,873	$ 4,405
2013	$ 147,457	$ 3,242	$ 2,315	$ -	$ -	$ -	$ 2,977	$ 2,977	$ 2,977	$ 4,565
2014	$ 139,692	$ 3,355	$ 2,396	$ -	$ -	$ -	$ 3,081	$ 3,081	$ 3,081	$ 4,724
2015	$ 129,465	$ 3,468	$ 2,477	$ -	$ -	$ -	$ 3,185	$ 3,185	$ 3,185	$ 4,883
2016	$ 134,391	$ 3,600	$ 2,571	$ -	$ -	$ -	$ 3,306	$ 3,306	$ 3,306	$ 5,069
2017	$ 124,957	$ 3,732	$ 2,665	$ -	$ -	$ -	$ 3,427	$ 3,427	$ 3,427	$ 5,255
2018	$ 129,375	$ 3,863	$ 2,760	$ -	$ -	$ -	$ 3,548	$ 3,548	$ 3,548	$ 5,440
2019	$ 128,771	$ 4,014	$ 2,867	$ -	$ -	$ -	$ 3,687	$ 3,687	$ 3,687	$ -
2020	$ 133,607	$ 4,165	$ 2,975	$ -	$ -	$ -	$ 3,825	$ 3,825	$ 3,825	$ -
2021	$ 121,997	$ 4,321	$ 3,087	$ -	$ -	$ -	$ 3,969	$ 3,969	$ 3,969	$ -
2022	$ 122,095	$ -	$ 3,203	$ -	$ -	$ -	$ 4,118	$ 4,118	$ 4,118	$ -
2023	$ 126,681	$ -	$ 3,323	$ -	$ -	$ -	$ 4,272	$ 4,272	$ 4,272	$ -
2024	$ 131,439	$ -	$ 3,448	$ -	$ -	$ -	$ 4,433	$ 4,433	$ 4,433	$ -
2025	$ 78,281	$ -	$ 3,577	$ -	$ -	$ -	$ 4,599	$ 4,599	$ 4,599	$ -
2026	$ 66,905	$ -	$ 3,712	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 69,417	$ -	$ 3,851	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 72,025	$ -	$ 3,996	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 74,730	$ -	$ 4,146	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkates
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Capital Expenditure Projection									
1999	$ 23,829	$ 23,829	$ 1,153	$ 7,905	$ 7,905	$ 7,905	$ 7,905	$ 838	$ 943
2000	$ 24,485	$ 24,485	$ 1,185	$ 8,122	$ 8,122	$ 8,122	$ 8,122	$ -	$ 969
2001	$ 25,141	$ 25,141	$ 1,216	$ 8,340	$ 8,340	$ 8,340	$ 8,340	$ -	$ 995
2002	$ 26,015	$ 26,015	$ 1,259	$ 8,630	$ 8,630	$ 8,630	$ 8,630	$ -	$ 1,030
2003	$ 26,671	$ 26,671	$ 1,290	$ 8,847	$ 8,847	$ 8,847	$ 8,847	$ -	$ 1,056
2004	$ 27,546	$ 27,546	$ 1,333	$ 9,137	$ 9,137	$ 9,137	$ 9,137	$ -	$ 1,090
2005	$ *28,420*	$ *28,420*	$ *1,375*	$ *9,428*	$ *9,428*	$ 9,428	$ *9,428*	$ -	$ 1,125
2006	$ 29,513	$ 29,513	$ 1,428	$ 9,790	$ 9,790	$ 9,790	$ 9,790	$ -	$ 1,168
2007	$ 30,388	$ 30,388	$ 1,470	$ 10,080	$ 10,080	$ 10,080	$ 10,080	$ -	$ 1,203
2008	$ 31,481	$ 31,481	$ 1,523	$ 10,443	$ 10,443	$ 10,443	$ 10,443	$ -	$ 1,246
2009	$ 32,574	$ 32,574	$ 1,576	$ 10,805	$ 10,805	$ 10,805	$ 10,805	$ -	$ 1,289
2010	$ 33,885	$ 33,885	$ 1,639	$ 11,240	$ 11,240	$ 11,240	$ 11,240	$ -	$ 1,341
2011	$ 34,978	$ 34,978	$ 1,692	$ 11,603	$ 11,603	$ 11,603	$ 11,603	$ -	$ 1,385
2012	$ 36,290	$ 36,290	$ 1,756	$ 12,038	$ 12,038	$ 12,038	$ 12,038	$ -	$ 1,437
2013	$ 37,602	$ 37,602	$ 1,819	$ 12,473	$ 12,473	$ 12,473	$ 12,473	$ -	$ 1,488
2014	$ 38,914	$ 38,914	$ 1,883	$ -	$ 12,908	$ 12,908	$ 12,908	$ -	$ 1,540
2015	$ 40,225	$ 40,225	$ 1,946	$ -	$ -	$ 13,344	$ 13,344	$ -	$ -
2016	$ 41,756	$ 41,756	$ 2,020	$ -	$ -	$ 13,851	$ 13,851	$ -	$ -
2017	$ 43,286	$ 43,286	$ 2,094	$ -	$ -	$ -	$ 14,359	$ -	$ -
2018	$ 44,816	$ 44,816	$ 2,168	$ -	$ -	$ -	$ 14,866	$ -	$ -
2019	$ 46,565	$ 46,565	$ 2,253	$ -	$ -	$ -	$ 15,447	$ -	$ -
2020	$ 48,314	$ 48,314	$ 2,338	$ -	$ -	$ -	$ 16,027	$ -	$ -
2021	$ 50,129	$ 50,129	$ 2,425	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 52,011	$ 52,011	$ 2,516	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 53,965	$ 53,965	$ 2,611	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 55,992	$ 55,992	$ 2,709	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 58,095	$ 2,811	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ *60,277*	$ *2,916*	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 62,541	$ 3,026	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 64,889	$ 3,139	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 67,327	$ 3,257	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Administrative & General Projection										
Allocated to Stations*										
1999	$ 64,014	$ -	$ 1,931	$ 1,886	$ 761	$ 913	$ 3,308	$ 2,764	$ 1,799	$ -
2000	$ 63,524	$ -	$ 1,984	$ 1,938	$ -	$ -	$ 3,399	$ 2,840	$ 1,848	$ -
2001	$ 65,226	$ -	$ 2,037	$ 1,989	$ -	$ -	$ 3,490	$ 2,916	$ 1,898	$ -
2002	$ 67,494	$ -	$ 2,108	$ 2,059	$ -	$ -	$ 3,611	$ 3,018	$ 1,964	$ -
2003	$ 69,196	$ -	$ 2,161	$ 2,111	$ -	$ -	$ 3,702	$ 3,094	$ 2,013	$ -
2004	$ 71,465	$ -	$ 2,232	$ 2,180	$ -	$ -	$ 3,823	$ 3,195	$ 2,079	$ -
2005	$ 71,484	$ -	$ 2,303	$ -	$ -	$ -	$ 3,945	$ 3,297	$ 2,145	$ -
2006	$ 74,234	$ -	$ 2,391	$ -	$ -	$ -	$ 4,097	$ 3,423	$ 2,228	$ -
2007	$ 76,433	$ -	$ 2,462	$ -	$ -	$ -	$ 4,218	$ 3,525	$ 2,294	$ -
2008	$ 79,183	$ -	$ 2,550	$ -	$ -	$ -	$ 4,370	$ 3,652	$ 2,376	$ -
2009	$ 81,932	$ -	$ 2,639	$ -	$ -	$ -	$ 4,521	$ 3,778	$ 2,459	$ -
2010	$ 85,231	$ -	$ 2,745	$ -	$ -	$ -	$ 4,704	$ 3,931	$ 2,558	$ -
2011	$ 87,981	$ -	$ 2,834	$ -	$ -	$ -	$ 4,855	$ 4,057	$ 2,640	$ -
2012	$ 91,260	$ -	$ 2,940	$ -	$ -	$ -	$ 5,037	$ 4,209	$ 2,739	$ -
2013	$ 94,579	$ -	$ 3,046	$ -	$ -	$ -	$ 5,219	$ 4,362	$ 2,838	$ -
2014	$ 86,771	$ -	$ 3,153	$ -	$ -	$ -	$ 5,401	$ 4,514	$ 2,937	$ -
2015	$ 75,277	$ -	$ 3,259	$ -	$ -	$ -	$ 5,584	$ 4,666	$ 3,036	$ -
2016	$ 78,141	$ -	$ 3,383	$ -	$ -	$ -	$ 5,796	$ 4,843	$ 3,152	$ -
2017	$ 81,005	$ -	$ 3,507	$ -	$ -	$ -	$ 6,008	$ 5,021	$ 3,267	$ -
2018	$ 83,869	$ -	$ 3,631	$ -	$ -	$ -	$ 6,221	$ 5,198	$ 3,383	$ -
2019	$ 87,142	$ -	$ 3,773	$ -	$ -	$ -	$ 6,464	$ 5,401	$ 3,515	$ -
2020	$ 90,415	$ -	$ 3,914	$ -	$ -	$ -	$ 6,706	$ 5,604	$ 3,647	$ -
2021	$ 93,810	$ -	$ 4,061	$ -	$ -	$ -	$ 6,958	$ 5,815	$ 3,784	$ -
2022	$ 97,334	$ -	$ 4,214	$ -	$ -	$ -	$ 7,220	$ 6,033	$ 3,926	$ -
2023	$ 100,990	$ -	$ 4,372	$ -	$ -	$ -	$ 7,491	$ 6,260	$ 4,073	$ -
2024	$ 104,783	$ -	$ 4,536	$ -	$ -	$ -	$ 7,772	$ 6,495	$ 4,226	$ -
2025	$ 68,200	$ -	$ 4,707	$ -	$ -	$ -	$ 8,064	$ 6,739	$ 4,385	$ -
2026	$ 50,853	$ -	$ 4,883	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 52,763	$ -	$ 5,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 54,745	$ -	$ 5,257	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 56,801	$ -	$ 5,455	$ -	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

ICF Resources, Inc. - Utilizing Dr. B. Venkates

(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Administrative & General Projection									
Allocated to Stations*									
1999	$ 16,620	$ 16,620	$ 1,553	$ 6,802	$ 6,802	$ -	$ -	$ 517	$ 1,739
2000	$ 17,077	$ 17,077	$ 1,596	$ 6,989	$ 6,989	$ -	$ -	$ -	$ 1,787
2001	$ 17,534	$ 17,534	$ 1,639	$ 7,177	$ 7,177	$ -	$ -	$ -	$ 1,835
2002	$ 18,144	$ 18,144	$ 1,696	$ 7,426	$ 7,426	$ -	$ -	$ -	$ 1,899
2003	$ 18,602	$ 18,602	$ 1,739	$ 7,613	$ 7,613	$ -	$ -	$ -	$ 1,947
2004	$ 19,212	$ 19,212	$ 1,796	$ 7,863	$ 7,863	$ -	$ -	$ -	$ 2,010
2005	$ 19,822	$ 19,822	$ 1,853	$ 8,113	$ 8,113	$ -	$ -	$ -	$ 2,074
2006	$ 20,584	$ 20,584	$ 1,924	$ 8,425	$ 8,425	$ -	$ -	$ -	$ 2,154
2007	$ 21,194	$ 21,194	$ 1,981	$ 8,674	$ 8,674	$ -	$ -	$ -	$ 2,218
2008	$ 21,956	$ 21,956	$ 2,052	$ 8,986	$ 8,986	$ -	$ -	$ -	$ 2,298
2009	$ 22,719	$ 22,719	$ 2,124	$ 9,298	$ 9,298	$ -	$ -	$ -	$ 2,377
2010	$ 23,633	$ 23,633	$ 2,209	$ 9,673	$ 9,673	$ -	$ -	$ -	$ 2,473
2011	$ 24,396	$ 24,396	$ 2,280	$ 9,985	$ 9,985	$ -	$ -	$ -	$ 2,553
2012	$ 25,311	$ 25,311	$ 2,366	$ 10,359	$ 10,359	$ -	$ -	$ -	$ 2,649
2013	$ 26,225	$ 26,225	$ 2,451	$ 10,734	$ 10,734	$ -	$ -	$ -	$ 2,744
2014	$ 27,140	$ 27,140	$ 2,537	$ -	$ 11,108	$ -	$ -	$ -	$ 2,840
2015	$ 28,055	$ 28,055	$ 2,622	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ 29,122	$ 29,122	$ 2,722	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ 30,190	$ 30,190	$ 2,822	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ 31,257	$ 31,257	$ 2,922	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ 32,477	$ 32,477	$ 3,036	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ 33,697	$ 33,697	$ 3,150	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ 34,962	$ 34,962	$ 3,268	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 36,275	$ 36,275	$ 3,391	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 37,638	$ 37,638	$ 3,518	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 39,051	$ 39,051	$ 3,650	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 40,518	$ 3,787	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 42,040	$ 3,930	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 43,619	$ 4,077	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 45,257	$ 4,230	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 46,957	$ 4,389	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Other Taxes										
Allocated to Stations*										
1999	$ 104,936	$ -	$ 3,165	$ 3,091	$ 1,247	$ 1,497	$ 5,422	$ 4,531	$ 2,949	$ -
2000	$ 101,344	$ -	$ 3,165	$ 3,091	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2001	$ 101,344	$ -	$ 3,165	$ 3,091	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2002	$ 101,344	$ -	$ 3,165	$ 3,091	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2003	$ 101,344	$ -	$ 3,165	$ 3,091	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2004	$ 101,344	$ -	$ 3,165	$ 3,091	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2005	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2006	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2007	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2008	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2009	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2010	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2011	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2012	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2013	$ 98,253	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2014	$ 87,103	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2015	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2016	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2017	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2018	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2019	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2020	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2021	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2022	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2023	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2024	$ 73,101	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2025	$ 45,857	$ -	$ 3,165	$ -	$ -	$ -	$ 5,422	$ 4,531	$ 2,949	$ -
2026	$ 32,955	$ -	$ 3,165	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 32,955	$ -	$ 3,165	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 32,955	$ -	$ 3,165	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 32,955	$ -	$ 3,165	$ -	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

ICF Resources, Inc. - Utilizing Dr. B. Venkates
(000)

Other Taxes	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
*Allocated to Stations**									
1999	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ 848	$ 2,851
2000	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2001	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2002	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2003	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2004	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2005	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2006	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2007	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2008	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2009	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2010	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2011	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2012	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2013	$ 27,244	$ 27,244	$ 2,547	$ 11,151	$ 11,151	$ -	$ -	$ -	$ 2,851
2014	$ 27,244	$ 27,244	$ 2,547	$ -	$ 11,151	$ -	$ -	$ -	$ 2,851
2015	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 27,244	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 27,244	$ 2,547	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Decommissioning										
1999	$ 31,344	$ 1,280	$ -	$ 366	$ 522	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2000	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2001	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2002	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2003	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2004	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2005	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2006	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2007	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2008	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2009	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2010	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2011	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2012	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2013	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2014	$ 25,044	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2015	$ 19,637	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2016	$ 19,637	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2017	$ 17,011	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2018	$ 17,011	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2019	$ 15,713	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ -
2020	$ 15,713	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ -
2021	$ 13,774	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ -
2022	$ 12,494	$ -	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ -
2023	$ 12,494	$ -	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ -
2024	$ 12,494	$ -	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ -
2025	$ 9,378	$ -	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ -
2026	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkates

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Decommissioning									
1999	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2000	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2001	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2002	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2003	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2004	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2005	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2006	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2007	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2008	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2009	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2010	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2011	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2012	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2013	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2014	$ 3,116	$ 5,138	$ -	$ -	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2015	$ 3,116	$ 5,138	$ -	$ -	$ -	$ 2,626	$ 1,939	$ -	$ -
2016	$ 3,116	$ 5,138	$ -	$ -	$ -	$ 2,626	$ 1,939	$ -	$ -
2017	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2018	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2019	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2020	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2021	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkateshwara's Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Required Life Extension Costs										
1999	$ 20,962	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2003	$ 87,981	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 87,981
2004	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2006	$ 97,356	$ 97,356	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2007	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ 235,481	$ -	$ -	$ -	$ -	$ -	$ 76,010	$ 76,010	$ 83,462	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 51,346	$ -	$ 17,115	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ICF Resources, Inc. - Utilizing Dr. B. Venkates
(000)

Required Life Extension Costs

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
1999	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,962
2000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2003	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2004	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2006	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2007	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ -	$ -	$ 34,231	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Present Value of Contribution Margin

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

Plant Name	(000) Net Present Value
Conemaugh	$ 187,519
Conowingo	393,812
Cromby 1	(6,806)
Cromby 2	(958)
Delaware	(844)
Eddystone 1	(19,004)
Eddystone 2	(12,554)
Eddystone3&4	89,001
Keystone	124,123
Limerick 1	141,956
Limerick 2	149,532
Muddy Run	206,771
P. Bottom 2	(370)
P. Bottom 3	7,729
Salem 1	(12,970)
Salem 2	(5,063)
Schuylkill	(478)
C. Turbines	95,772
Total NPV of Contribution Margin	**$ 1,337,170**
Total NPV excluding Negative Values	**$ 1,396,215**
Inventory and Working Capital Carrying Charges	(162,363)
Future Tax Depreciation Benefits	270,512
Accumulated Deferred Investment Tax Credit Benefits	133,360
Deferred Income Tax	400,598
Total Adjusted NPV excluding Negative Values	**$ 2,038,322**

Exhibit TPH-4

Market Value of Generating Units by Year

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Net Present Value	$1,337,170	$187,519	$393,812	($6,806)	($958)	($844)	($19,004)	($12,554)	$89,001	$124,123

(Market Value Revenue - Est. Fuel Cost - Est. O&M - Est. Capital - A&G - Taxes - Decomm. - Required Life Extension*) x (1-T)*

*After-Tax Cash Contribution Margin***				***						
1999	$ (55,714)	$ 7,087	$ 15,727	$ (1,512)	$ (1,043)	$ (919)	$ (2,638)	$ (2,278)	$ (3,381)	$ 8,127
2000	$ (4,942)	$ 10,211	$ 20,362	$ (1,512)	$ -	$ -	$ (2,638)	$ (2,278)	$ 1,847	$ 10,450
2001	$ 92,009	$ 15,371	$ 27,963	$ (1,512)	$ -	$ -	$ (2,638)	$ (983)	$ 11,514	$ 14,731
2002	$ 101,518	$ 16,202	$ 29,275	$ (1,512)	$ -	$ -	$ (2,638)	$ (1,087)	$ 11,792	$ 14,538
2003	$ 60,824	$ 17,136	$ 30,738	$ (1,512)	$ -	$ -	$ (2,638)	$ (1,920)	$ 11,530	$ (37,144)
2004	$ 123,464	$ 18,067	$ 32,206	$ (1,512)	$ -	$ -	$ (2,638)	$ (2,029)	$ 11,835	$ 13,995
2005	$ 136,701	$ 19,640	$ 33,544	$ -	$ -	$ -	$ (2,638)	$ (1,917)	$ 12,145	$ 15,001
2006	$ 88,830	$ (35,690)	$ 34,874	$ -	$ -	$ -	$ (2,638)	$ (1,910)	$ 12,392	$ 16,029
2007	$ 158,298	$ 23,070	$ 36,348	$ -	$ -	$ -	$ (2,638)	$ (1,734)	$ 12,741	$ 17,191
2008	$ 169,309	$ 24,940	$ 37,819	$ -	$ -	$ -	$ (2,638)	$ (1,661)	$ 13,028	$ 18,384
2009	$ 181,585	$ 26,940	$ 39,364	$ -	$ -	$ -	$ (2,638)	$ (1,551)	$ 13,337	$ 19,667
2010	$ 143,719	$ 28,452	$ 40,960	$ -	$ -	$ -	$ (2,638)	$ (1,070)	$ (35,625)	$ 21,001
2011	$ 211,234	$ 30,112	$ 42,717	$ -	$ -	$ -	$ -	$ -	$ 13,145	$ 22,477
2012	$ 224,325	$ 31,813	$ 44,489	$ -	$ -	$ -	$ -	$ -	$ 12,991	$ 23,991
2013	$ 238,797	$ 33,614	$ 46,354	$ -	$ -	$ -	$ -	$ -	$ 12,824	$ 25,601
2014	$ 214,492	$ 35,521	$ 38,304	$ -	$ -	$ -	$ -	$ -	$ 12,641	$ 27,312
2015	$ 229,625	$ 37,537	$ 50,383	$ -	$ -	$ -	$ -	$ -	$ 12,441	$ 29,128
2016	$ 240,592	$ 38,994	$ 52,365	$ -	$ -	$ -	$ -	$ -	$ 13,042	$ 30,265
2017	$ 251,934	$ 40,450	$ 54,347	$ -	$ -	$ -	$ -	$ -	$ 13,643	$ 31,402
2018	$ 262,860	$ 41,907	$ 56,329	$ -	$ -	$ -	$ -	$ -	$ 14,244	$ 32,539
2019	$ 241,507	$ 43,572	$ 58,594	$ -	$ -	$ -	$ -	$ -	$ 14,931	$ -
2020	$ 252,693	$ 45,236	$ 60,859	$ -	$ -	$ -	$ -	$ -	$ 15,618	$ -
2021	$ 261,491	$ 46,963	$ 63,210	$ -	$ -	$ -	$ -	$ -	$ 16,331	$ -
2022	$ 224,630	$ -	$ 65,648	$ -	$ -	$ -	$ -	$ -	$ 17,070	$ -
2023	$ 235,112	$ -	$ 68,178	$ -	$ -	$ -	$ -	$ -	$ 17,838	$ -
2024	$ 245,987	$ -	$ 70,804	$ -	$ -	$ -	$ -	$ -	$ 18,634	$ -
2025	$ 191,861	$ -	$ 73,527	$ -	$ -	$ -	$ -	$ -	$ 19,460	$ -
2026	$ 179,917	$ -	$ 76,353	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 187,716	$ -	$ 79,286	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 195,808	$ -	$ 82,328	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 204,204	$ -	$ 85,485	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

* *Assumes all capital additions are currently tax deductible. Capital also includes required life extension costs.*

** *If contribution margin is negative then plant does not operate, but incurs taxes and decommissioning costs.*

*** *Shaded areas indicate plant does not operate.*

Market Value of Generating Units by Year

Putnam, Hayes & Bartlett - Utilizing W. Hier

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Net Present Value	$141,956	$149,532	$206,771	($370)	$7,729	($12,970)	($5,063)	($478)	$95,772

After-Tax Cash Contribution Margin*						***			
1999	$ (18,566)	$ (19,749)	$ 651	$ (10,019)	$ (10,016)	$ (1,536)	$ (1,135)	$ (521)	$ (14,016)
2000	$ (15,638)	$ (16,212)	$ 6,958	$ (9,102)	$ (8,775)	$ (1,536)	$ (1,135)	$ -	$ 4,054
2001	$ 964	$ 153	$ 18,268	$ (2,095)	$ (1,672)	$ (1,536)	$ (1,135)	$ -	$ 14,615
2002	$ 3,380	$ 2,305	$ 18,744	$ (1,141)	$ (612)	$ (1,536)	$ (1,135)	$ -	$ 14,942
2003	$ 6,782	$ 5,416	$ 19,307	$ 202	$ 845	$ (1,536)	$ (1,135)	$ -	$ 14,753
2004	$ 9,798	$ 8,110	$ 19,845	$ 1,297	$ 2,066	$ (1,536)	$ (1,135)	$ -	$ 15,094
2005	$ 12,224	$ 10,340	$ 20,358	$ 2,214	$ 3,007	$ (1,536)	$ (1,135)	$ -	$ 15,452
2006	$ 13,778	$ 11,682	$ 20,834	$ 2,791	$ 3,609	$ (1,536)	$ (1,135)	$ -	$ 15,749
2007	$ 16,236	$ 13,909	$ 21,390	$ 3,736	$ 4,580	$ (1,536)	$ (1,135)	$ -	$ 16,140
2008	$ 18,234	$ 15,659	$ 21,909	$ 4,482	$ 5,352	$ (1,536)	$ (1,135)	$ -	$ 16,472
2009	$ 20,558	$ 17,715	$ 22,451	$ 5,334	$ 6,230	$ (1,536)	$ (1,108)	$ -	$ 16,821
2010	$ 22,548	$ 19,626	$ 22,931	$ 6,042	$ 6,980	$ (1,536)	$ (1,009)	$ -	$ 17,057
2011	$ 25,651	$ 22,648	$ 23,492	$ 7,233	$ 8,215	$ (1,536)	$ (304)	$ -	$ 17,384
2012	$ 28,258	$ 25,169	$ 24,015	$ 8,198	$ 9,226	$ (1,536)	$ 62	$ -	$ 17,650
2013	$ 31,193	$ 28,014	$ 24,562	$ 9,299	$ 10,375	$ (1,536)	$ 568	$ -	$ 17,930
2014	$ 34,470	$ 31,197	$ 5,104	$ -	$ 11,669	$ (1,173)	$ 1,222	$ -	$ 18,226
2015	$ 38,105	$ 34,734	$ 25,726	$ -	$ -	$ (458)	$ 2,030	$ -	$ -
2016	$ 40,443	$ 36,989	$ 26,760	$ -	$ -	$ (417)	$ 2,151	$ -	$ -
2017	$ 42,781	$ 39,245	$ 27,795	$ -	$ -	$ -	$ 2,271	$ -	$ -
2018	$ 45,120	$ 41,500	$ 28,829	$ -	$ -	$ -	$ 2,392	$ -	$ -
2019	$ 47,792	$ 44,077	$ 30,011	$ -	$ -	$ -	$ 2,529	$ -	$ -
2020	$ 50,465	$ 46,655	$ 31,193	$ -	$ -	$ -	$ 2,667	$ -	$ -
2021	$ 53,238	$ 49,329	$ 32,420	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 56,115	$ 52,103	$ 33,693	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 59,100	$ 54,982	$ 35,013	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 62,197	$ 57,969	$ 36,383	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 61,068	$ 37,805	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 64,284	$ 39,280	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 67,620	$ 40,810	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 71,082	$ 42,398	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 74,674	$ 44,046	$ -	$ -	$ -	$ -	$ -	$ -

** *If contribution margin is negative then plant does not operate, but incurs taxes and decommissioning costs.*

*** *Shaded areas indicate plant does not operate.*

Operating Assumptions

Data Inputs		Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Plant Name		Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Capacity (MW)		9,029	332	512	345		250	1,341			340
Case Description:		**Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates**									
Plant Type			Coal	Water	Coal	Gas	Oil	Coal	Coal	Gas	Coal
Decommissioning:											
Decommissioning Year - Adjusted			2021	2029	2004	1999	1999	2010	2010	2025	2018
Decommissioning Year - Nameplate			2006	2014	2004	1999	1999	2010	2010	2010	2003
Life Extension Years			15	15	0	0	0	0	0	15	15
Required Life Extension Costs	1997	$ 256,000	$ 75,000	$ 10,000	$ -	$ -	$ -	$ -	$ -	$ 56,000	$ 75,000
Decommissioning Exp.	Flat	$ 31,344	$ 1,280	$ -	$ 366	$ 522	$ -	$ 710	$ 768	$ 2,762	$ 1,298
O&M Buildup:											
Fixed Charge - $000	1997	$ 444,432	$ 7,677	$ 8,950	$ 6,762	$ 3,842	$ 4,789	$ 11,582	$ 9,528	$ 9,093	$ 6,811
Incremental Charge - $/MWhr	1997		$ -	$ 0.69	$ 3.38	$ 0.51	$ 1.68	$ 4.07	$ 3.24	$ 0.48	$ -
NOX 1999-2002 $/MWhr	1997		$ -	$ -	$ 1.09	$ 1.43	$ 0.20	$ 0.64	$ 1.69	$ 0.79	$ -
NOX 2003&Thereafter $/MWhr	1997		$ -	$ -	$ 2.52	$ 3.10	$ 0.76	$ 1.06	$ 2.34	$ 1.81	$ -
Merrill Creek	Flat	$ 16,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1997 Operating & Maintenance - Base		$ 460,832	$ 7,677	$ 8,950	$ 6,762	$ 3,842	$ 4,789	$ 11,582	$ 9,528	$ 9,093	$ 6,811
1996 Operating & Maintenance -Estimate		$ 493,881	$ -	$ 8,555	$ 8,659	$ 5,146	$ 5,220	$ 17,706	$ 13,982	$ 8,342	$ -
1995 Operating & Maintenance - Actual		$ 486,254	$ 10,758	$ 8,018	$ 8,849	$ 7,398	$ 7,736	$ 23,358	$ 16,841	$ 6,915	$ 9,685
1994 Operating & Maintenance - Actual		$ 507,353	$ 11,395	$ 9,942	$ 14,466	$ 5,540	$ 7,742	$ 25,813	$ 21,560	$ 19,702	$ 10,933
Capital Expenditures:											
1997 Capital Expenditures Base		93,960	$ 1,960	$ 1,400	$ 1,500	$ 900	$ 1,600	$ 1,800	$ 1,800	$ 1,800	$ 2,760
1996 Capital Expenditures Estimate		203,205	$ 5,196	$ 13,306	$ 140	$ 1,654	$ 100	$ 1,154	$ 1,124	$ 890	$ 3,761
1995 Capital Expenditures Actual		169,267	$ 8,751	$ 5,958	$ 429	$ 3,334	$ 154	$ 8,415	$ 5,141	$ 3,573	$ 7,275
1994 Capital Expenditures Actual		198,807	$ 27,638	$ 943	$ 10,217	$ 827	$ 1,617	$ 5,895	$ 4,393	$ 13,223	$ 11,156
Other Costs:											
Admin & General Exp.	1995	$ 58,728	$ -	$ 1,643	$ 1,241	$ 705	$ 879	$ 2,126	$ 1,749	$ 1,669	$ -
Other Taxes	1995	$ 104,936	$ -	$ 2,935	$ 2,218	$ 1,260	$ 1,571	$ 3,799	$ 3,125	$ 2,982	$ -
Allocation Factors:											
1997 O&M ex Salem,Keystone&Conemaugh		319,956	$ -	$ 8,950	$ 6,762	$ 3,842	$ 4,789	$ 11,582	$ 9,528	$ 9,093	$ -
			0.0%	*2.8%*	*2.1%*	*1.2%*	*1.5%*	*3.6%*	*3.0%*	*2.8%*	*0.0%*

Operating Assumptions

Data Inputs		Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Plant Name										
Capacity (MW)		2,170		880	929		942		166	822
Case Description:										
Plant Type		Nuc	Nuc	Water	Nuc	Nuc	Nuc	Nuc	Oil	Oil
Decommissioning:										
Decommissioning Year - Adjusted		2024	2029	2029	2013	2014	2016	2020	1999	2014
Decommissioning Year - Nameplate		2024	2029	2014	2013	2014	2016	2020	1999	1999
Life Extension Years		0	0	15	0	0	0	0	0	15
Required Life Extension Costs	1997	$ -	$ -	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ 20,000
Decommissioning Exp.	Flat	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
O&M Buildup:										
Fixed Charge - $000	1997	$ 79,053	$ 79,053	$ 7,639	$ 35,711	$ 35,711	$ 63,194	$ 63,194	$ 2,713	$ 9,131
Incremental Charge - $/MWhr	1997	$ -	$ -	$ 0.45	$ -	$ -	$ -	$ -	$ 0.43	$ 2.22
NOX 1999-2002 $/MWhr	1997	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,080
NOX 2003&Thereafter $/MWhr	1997	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.31	$ 1,960
Merrill Creek	Flat	$ 8,200	$ 8,200	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1997 Operating & Maintenance - Base		$ 87,253	$ 87,253	$ 7,639	$ 35,711	$ 35,711	$ 63,194	$ 63,194	$ 2,713	$ 9,131
1996 Operating & Maintenance -Estimate		$ 96,815	$ 68,700	$ 6,164	$ 46,458	$ 23,357	$ 84,490	$ 93,287	$ 7,000	$ -
1995 Operating & Maintenance - Actual		$ 76,315	$ 91,630	$ 4,708	$ 28,435	$ 47,823	$ 73,035	$ 58,183	$ 2,910	$ 3,657
1994 Operating & Maintenance - Actual		$ 98,434	$ 74,749	$ 4,870	$ 53,885	$ 25,631	$ 60,924	$ 55,692	$ 6,075	$ -
Capital Expenditures:		**	**							
1997 Capital Expenditures Base		$ 22,736	$ 22,736	$ 1,100	$ 7,542	$ 7,542	$ 7,542	$ 7,542	$ 800	$ 900
1996 Capital Expenditures Estimate		$ 19,119	$ 7,707	$ 12,067	$ 8,108	$ 5,130	$ 75,015	$ 47,698	$ 47	$ 989
1995 Capital Expenditures Actual		$ 16,445	$ 23,350	$ 3,930	$ 9,449	$ 12,511	$ 30,773	$ 29,433	$ 84	$ 262
1994 Capital Expenditures Actual		$ 22,183	$ 23,474	$ 3,830	$ 23,061	$ 5,891	$ 20,218	$ 20,800	$ 1,509	$ 1,932
		** includes Carrying Charges on Limerick fuel inventory								
Other Costs:										
Admin & General Exp.	1995	$ 16,015	$ 16,015	$ 1,402	$ 6,555	$ 6,555	$ -	$ -	$ 498	$ 1,676
Other Taxes	1995	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ 890	$ 2,995
Allocation Factors:										
1997 O&M ex Salem,Keystone&Conemaugh		$ 87,253	$ 87,253	$ 7,639	$ 35,711	$ 35,711	$ -	$ -	$ 2,713	$ 9,131
		27.3%	*27.3%*	*2.4%*	*11.2%*	*11.2%*	*0.0%*	*0.0%*	*0.8%*	*2.9%*

General Assumption	
Discount Rate	8.88%
Income Tax Rate	41.493%

Growth Assumptions		
Year	Annual GDP Deflator	Cumulative GDP Deflator
1995	Base	Base
1996	1.0200	1.0200
1997	1.0196	1.0400
1998	1.0288	1.0700
1999	1.0187	1.0900
2000	1.0275	1.1200
2001	1.0268	1.1500
2002	1.0348	1.1900
2003	1.0252	1.2200
2004	1.0328	1.2600
2005	1.0317	1.3000
2006	1.0385	1.3500
2007	1.0296	1.3900
2008	1.0360	1.4400
2009	1.0347	1.4900
2010	1.0403	1.5500
2011	1.0323	1.6000
2012	1.0375	1.6600
2013	1.0361	1.7200
2014	1.0349	1.7800
2015	1.0337	1.8400
2016	1.0360	1.9100
2017	1.0366	1.9800
2018	1.0354	2.0500
2019	1.0390	2.1300
2020	1.0376	2.2100
2021	1.0376	2.2930
2022	1.0376	2.3791
2023	1.0376	2.4685
2024	1.0376	2.5612
2025	1.0376	2.6574
2026	1.0376	2.7572
2027	1.0376	2.8608
2028	1.0376	2.9682
2029	1.0376	3.0797

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Generation Projection (MWhrs)										
1999	39,046,869	2,631,373	1,692,159	1,000,919	424,662	444,553	2,002,379	2,030,177	952,342	2,656,735
2000	37,848,557	2,633,143	1,692,327	981,698	-	-	1,989,297	2,005,018	941,327	2,658,471
2001	37,819,118	2,634,915	1,692,495	962,846	-	-	1,976,301	1,980,171	930,440	2,660,207
2002	37,792,126	2,636,687	1,692,663	944,356	-	-	1,963,390	1,955,631	919,678	2,661,944
2003	37,767,700	2,638,461	1,692,831	926,222	-	-	1,950,563	1,931,396	909,041	2,663,683
2004	37,745,971	2,640,237	1,692,999	908,435	-	-	1,937,820	1,907,462	898,527	2,665,423
2005	36,872,705	2,638,648	1,692,999	-	-	-	1,950,848	1,933,978	881,872	2,663,825
2006	36,912,731	2,637,061	1,692,999	-	-	-	1,963,963	1,960,864	865,525	2,662,229
2007	36,958,081	2,635,475	1,693,000	-	-	-	1,977,167	1,988,123	849,482	2,660,634
2008	37,009,282	2,633,889	1,693,000	-	-	-	1,990,459	2,015,762	833,736	2,659,039
2009	37,066,925	2,632,305	1,693,000	-	-	-	2,003,840	2,043,784	818,282	2,657,446
2010	37,066,925	2,632,305	1,693,000	-	-	-	2,003,840	2,043,784	818,282	2,657,446
2011	33,019,301	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2012	33,019,301	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2013	33,019,301	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2014	30,207,533	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2015	27,387,287	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2016	27,387,287	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2017	24,532,769	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2018	24,532,769	2,632,305	1,693,000	-	-	-	-	-	818,282	2,657,446
2019	21,875,323	2,632,305	1,693,000	-	-	-	-	-	818,282	-
2020	21,875,323	2,632,305	1,693,000	-	-	-	-	-	818,282	-
2021	19,020,805	2,632,305	1,693,000	-	-	-	-	-	818,282	-
2022	16,388,500	-	1,693,000	-	-	-	-	-	818,282	-
2023	16,388,500	-	1,693,000	-	-	-	-	-	818,282	-
2024	16,388,500	-	1,693,000	-	-	-	-	-	818,282	-
2025	9,692,240	-	1,693,000	-	-	-	-	-	818,282	-
2026	8,873,958	-	1,693,000	-	-	-	-	-	-	-
2027	8,873,958	-	1,693,000	-	-	-	-	-	-	-
2028	8,873,958	-	1,693,000	-	-	-	-	-	-	-
2029	8,873,958	-	1,693,000	-	-	-	-	-	-	-

Putnam, Hayes & Bartlett - Utilizing W. Hier

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Generation Projection (MWhrs)									
1999	6,694,050	6,694,050	180,258	2,810,839	2,810,839	2,853,576	2,853,576	297,321	17,062
2000	6,698,908	6,698,908	196,114	2,812,880	2,812,880	2,855,647	2,855,647	-	16,292
2001	6,703,770	6,703,770	213,364	2,814,921	2,814,921	2,857,720	2,857,720	-	15,557
2002	6,708,636	6,708,636	232,132	2,816,964	2,816,964	2,859,794	2,859,794	-	14,855
2003	6,713,505	6,713,505	252,551	2,819,009	2,819,009	2,861,869	2,861,869	-	14,185
2004	6,718,378	6,718,378	274,766	2,821,055	2,821,055	2,863,947	2,863,947	-	13,546
2005	6,713,948	6,713,948	307,798	2,819,195	2,819,195	2,862,058	2,862,058	-	12,334
2006	6,709,522	6,709,522	344,799	2,817,336	2,817,336	2,860,171	2,860,171	-	11,231
2007	6,705,098	6,705,098	386,250	2,815,479	2,815,479	2,858,286	2,858,286	-	10,226
2008	6,700,678	6,700,678	432,683	2,813,622	2,813,622	2,856,401	2,856,401	-	9,312
2009	6,696,260	6,696,260	484,698	2,811,767	2,811,767	2,854,518	2,854,518	-	8,479
2010	6,696,260	6,696,260	484,698	2,811,767	2,811,767	2,854,518	2,854,518	-	8,479
2011	6,696,260	6,696,260	484,698	2,811,767	2,811,767	2,854,518	2,854,518	-	8,479
2012	6,696,260	6,696,260	484,698	2,811,767	2,811,767	2,854,518	2,854,518	-	8,479
2013	6,696,260	6,696,260	484,698	2,811,767	2,811,767	2,854,518	2,854,518	-	8,479
2014	6,696,260	6,696,260	484,698	-	2,811,767	2,854,518	2,854,518	-	8,479
2015	6,696,260	6,696,260	484,698	-	-	2,854,518	2,854,518	-	-
2016	6,696,260	6,696,260	484,698	-	-	2,854,518	2,854,518	-	-
2017	6,696,260	6,696,260	484,698	-	-	-	2,854,518	-	-
2018	6,696,260	6,696,260	484,698	-	-	-	2,854,518	-	-
2019	6,696,260	6,696,260	484,698	-	-	-	2,854,518	-	-
2020	6,696,260	6,696,260	484,698	-	-	-	2,854,518	-	-
2021	6,696,260	6,696,260	484,698	-	-	-	-	-	-
2022	6,696,260	6,696,260	484,698	-	-	-	-	-	-
2023	6,696,260	6,696,260	484,698	-	-	-	-	-	-
2024	6,696,260	6,696,260	484,698	-	-	-	-	-	-
2025	-	6,696,260	484,698	-	-	-	-	-	-
2026	-	6,696,260	484,698	-	-	-	-	-	-
2027	-	6,696,260	484,698	-	-	-	-	-	-
2028	-	6,696,260	484,698	-	-	-	-	-	-
2029	-	6,696,260	484,698	-	-	-	-	-	-

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Market Price Rate ($/MWhr)										
Energy & Capacity										
1999	$ 24.18	$ 19.99	$ 25.81	$ 22.40	$ 36.01	$ 40.87	$ 22.40	$ 22.68	$ 46.02	$ 20.08
2000	$ 27.55	$ 22.42	$ 30.72	$ 25.37	$ -	$ -	$ 25.17	$ 25.62	$ 58.41	$ 22.56
2001	$ 33.60	$ 26.18	$ 38.61	$ 29.94	$ -	$ -	$ 29.37	$ 30.15	$ 79.10	$ 26.36
2002	$ 35.00	$ 27.17	$ 40.24	$ 31.50	$ -	$ -	$ 30.69	$ 31.58	$ 83.06	$ 27.40
2003	$ 36.47	$ 28.20	$ 41.94	$ 33.14	$ -	$ -	$ 32.07	$ 33.08	$ 87.25	$ 28.48
2004	$ 38.01	$ 29.28	$ 43.71	$ 34.87	$ -	$ -	$ 33.51	$ 34.65	$ 91.68	$ 29.61
2005	$ 39.58	$ 30.75	$ 45.37	$ -	$ -	$ -	$ 34.76	$ 35.80	$ 96.37	$ 31.07
2006	$ 41.13	$ 32.30	$ 47.08	$ -	$ -	$ -	$ 36.06	$ 36.98	$ 101.30	$ 32.62
2007	$ 42.75	$ 33.94	$ 48.87	$ -	$ -	$ -	$ 37.40	$ 38.21	$ 106.50	$ 34.24
2008	$ 44.44	$ 35.66	$ 50.73	$ -	$ -	$ -	$ 38.81	$ 39.49	$ 111.99	$ 35.95
2009	$ 46.19	$ 37.49	$ 52.67	$ -	$ -	$ -	$ 40.26	$ 40.82	$ 117.77	$ 37.75
2010	$ 48.04	$ 39.06	$ 54.73	$ -	$ -	$ -	$ 41.97	$ 42.53	$ 121.45	$ 39.34
2011	$ 50.70	$ 40.71	$ 56.88	$ -	$ -	$ -	$ -	$ -	$ 125.26	$ 41.00
2012	$ 52.72	$ 42.43	$ 59.12	$ -	$ -	$ -	$ -	$ -	$ 129.20	$ 42.74
2013	$ 54.84	$ 44.23	$ 61.45	$ -	$ -	$ -	$ -	$ -	$ 133.27	$ 44.55
2014	$ 57.59	$ 46.11	$ 63.89	$ -	$ -	$ -	$ -	$ -	$ 137.49	$ 46.44
2015	$ 58.19	$ 48.07	$ 66.42	$ -	$ -	$ -	$ -	$ -	$ 141.86	$ 48.42
2016	$ 60.40	$ 49.90	$ 68.95	$ -	$ -	$ -	$ -	$ -	$ 147.25	$ 50.26
2017	$ 63.27	$ 51.73	$ 71.48	$ -	$ -	$ -	$ -	$ -	$ 152.65	$ 52.10
2018	$ 65.51	$ 53.56	$ 74.00	$ -	$ -	$ -	$ -	$ -	$ 158.05	$ 53.95
2019	$ 69.52	$ 55.65	$ 76.89	$ -	$ -	$ -	$ -	$ -	$ 164.21	$ -
2020	$ 72.13	$ 57.74	$ 79.78	$ -	$ -	$ -	$ -	$ -	$ 170.38	$ -
2021	$ 75.94	$ 59.91	$ 82.77	$ -	$ -	$ -	$ -	$ -	$ 176.78	$ -
2022	$ 81.47	$ -	$ 85.88	$ -	$ -	$ -	$ -	$ -	$ 183.42	$ -
2023	$ 84.52	$ -	$ 89.11	$ -	$ -	$ -	$ -	$ -	$ 190.31	$ -
2024	$ 87.70	$ -	$ 92.46	$ -	$ -	$ -	$ -	$ -	$ 197.46	$ -
2025	$ 100.27	$ -	$ 95.93	$ -	$ -	$ -	$ -	$ -	$ 204.87	$ -
2026	$ 94.03	$ -	$ 99.53	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 97.56	$ -	$ 103.27	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 101.23	$ -	$ 107.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 105.03	$ -	$ 111.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hier

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Market Price Rate ($/MWhr)									
Energy & Capacity									
1999	$ 22.34	$ 22.55	$ 104.55	$ 22.42	$ 22.56	$ 22.34	$ 22.68	$ 40.25	$ 1,039.36
2000	$ 25.43	$ 25.59	$ 155.85	$ 25.46	$ 25.66	$ 25.38	$ 25.72	$ -	$ 1,728.40
2001	$ 30.17	$ 30.27	$ 238.67	$ 30.16	$ 30.41	$ 30.07	$ 30.41	$ -	$ 2,997.13
2002	$ 31.51	$ 31.54	$ 228.18	$ 31.44	$ 31.76	$ 31.35	$ 31.69	$ -	$ 3,212.81
2003	$ 32.92	$ 32.87	$ 218.50	$ 32.79	$ 33.17	$ 32.69	$ 33.03	$ -	$ 3,444.07
2004	$ 34.40	$ 34.27	$ 209.60	$ 34.19	$ 34.66	$ 34.10	$ 34.43	$ -	$ 3,692.28
2005	$ 35.79	$ 35.61	$ 195.71	$ 35.57	$ 36.05	$ 35.44	$ 35.88	$ -	$ 4,134.26
2006	$ 37.25	$ 37.01	$ 183.11	$ 37.01	$ 37.50	$ 36.85	$ 37.39	$ -	$ 4,630.54
2007	$ 38.76	$ 38.47	$ 171.71	$ 38.50	$ 39.01	$ 38.31	$ 38.98	$ -	$ 5,187.80
2008	$ 40.35	$ 39.99	$ 161.41	$ 40.06	$ 40.59	$ 39.83	$ 40.63	$ -	$ 5,813.64
2009	$ 42.00	$ 41.57	$ 152.10	$ 41.69	$ 42.23	$ 41.41	$ 42.36	$ -	$ 6,516.59
2010	$ 43.74	$ 43.30	$ 156.77	$ 43.42	$ 43.99	$ 43.13	$ 44.13	$ -	$ 6,680.47
2011	$ 45.57	$ 45.10	$ 161.60	$ 45.23	$ 45.83	$ 44.93	$ 45.97	$ -	$ 6,848.49
2012	$ 47.47	$ 46.99	$ 166.59	$ 47.12	$ 47.74	$ 46.80	$ 47.89	$ -	$ 7,020.76
2013	$ 49.46	$ 48.95	$ 171.75	$ 49.09	$ 49.74	$ 48.76	$ 49.90	$ -	$ 7,197.38
2014	$ 51.54	$ 51.00	$ 177.09	$ -	$ 51.83	$ 50.80	$ 52.00	$ -	$ 7,378.48
2015	$ 53.71	$ 53.15	$ 182.61	$ -	$ -	$ 52.94	$ 54.19	$ -	$ -
2016	$ 55.75	$ 55.17	$ 189.56	$ -	$ -	$ 54.95	$ 56.25	$ -	$ -
2017	$ 57.79	$ 57.19	$ 196.51	$ -	$ -	$ -	$ 58.31	$ -	$ -
2018	$ 59.83	$ 59.21	$ 203.45	$ -	$ -	$ -	$ 60.37	$ -	$ -
2019	$ 62.17	$ 61.52	$ 211.39	$ -	$ -	$ -	$ 62.73	$ -	$ -
2020	$ 64.50	$ 63.83	$ 219.33	$ -	$ -	$ -	$ 65.08	$ -	$ -
2021	$ 66.93	$ 66.23	$ 227.57	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 69.44	$ 68.72	$ 236.12	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 72.05	$ 71.30	$ 244.98	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 74.76	$ 73.98	$ 254.19	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 76.76	$ 263.73	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 79.64	$ 273.64	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 82.63	$ 283.92	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 85.73	$ 294.58	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 88.95	$ 305.64	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Market Price Revenues	*(generation x market rate) (000's)*									
Energy & Capacity										
1999	$ 944,176	$ 52,600	$ 43,679	$ 22,417	$ 15,292	$ 18,168	$ 44,858	$ 46,041	$ 43,829	$ 53,359
2000	$ 1,042,552	$ 59,041	$ 51,983	$ 24,910	$ -	$ -	$ 50,061	$ 51,378	$ 54,980	$ 59,969
2001	$ 1,270,666	$ 68,984	$ 65,356	$ 28,823	$ -	$ -	$ 58,042	$ 59,702	$ 73,596	$ 70,124
2002	$ 1,322,877	$ 71,645	$ 68,108	$ 29,744	$ -	$ -	$ 60,254	$ 61,761	$ 76,390	$ 72,937
2003	$ 1,377,504	$ 74,414	$ 70,989	$ 30,695	$ -	$ -	$ 62,553	$ 63,893	$ 79,313	$ 75,869
2004	$ 1,434,710	$ 77,296	$ 74,008	$ 31,678	$ -	$ -	$ 64,945	$ 66,101	$ 82,378	$ 78,925
2005	$ 1,459,413	$ 81,136	$ 76,804	$ -	$ -	$ -	$ 67,812	$ 69,230	$ 84,982	$ 82,776
2006	$ 1,518,383	$ 85,181	$ 79,713	$ -	$ -	$ -	$ 70,813	$ 72,518	$ 87,679	$ 86,830
2007	$ 1,580,081	$ 89,444	$ 82,740	$ -	$ -	$ -	$ 73,954	$ 75,974	$ 90,473	$ 91,097
2008	$ 1,644,661	$ 93,938	$ 85,890	$ -	$ -	$ -	$ 77,242	$ 79,606	$ 93,367	$ 95,589
2009	$ 1,712,285	$ 98,674	$ 89,167	$ -	$ -	$ -	$ 80,684	$ 83,423	$ 96,366	$ 100,318
2010	$ 1,780,773	$ 102,828	$ 92,658	$ -	$ -	$ -	$ 84,093	$ 86,930	$ 99,378	$ 104,546
2011	$ 1,673,972	$ 107,169	$ 96,296	$ -	$ -	$ -	$ -	$ -	$ 102,495	$ 108,962
2012	$ 1,740,927	$ 111,701	$ 100,088	$ -	$ -	$ -	$ -	$ -	$ 105,719	$ 113,574
2013	$ 1,810,735	$ 116,434	$ 104,040	$ -	$ -	$ -	$ -	$ -	$ 109,055	$ 118,390
2014	$ 1,739,700	$ 121,376	$ 108,158	$ -	$ -	$ -	$ -	$ -	$ 112,506	$ 123,419
2015	$ 1,593,546	$ 126,537	$ 112,451	$ -	$ -	$ -	$ -	$ -	$ 116,079	$ 128,671
2016	$ 1,654,170	$ 131,351	$ 116,729	$ -	$ -	$ -	$ -	$ -	$ 120,495	$ 133,566
2017	$ 1,552,186	$ 136,165	$ 121,007	$ -	$ -	$ -	$ -	$ -	$ 124,911	$ 138,461
2018	$ 1,607,061	$ 140,979	$ 125,285	$ -	$ -	$ -	$ -	$ -	$ 129,327	$ 143,356
2019	$ 1,520,825	$ 146,481	$ 130,175	$ -	$ -	$ -	$ -	$ -	$ 134,374	$ -
2020	$ 1,577,945	$ 151,982	$ 135,064	$ -	$ -	$ -	$ -	$ -	$ 139,420	$ -
2021	$ 1,444,451	$ 157,690	$ 140,137	$ -	$ -	$ -	$ -	$ -	$ 144,657	$ -
2022	$ 1,335,090	$ -	$ 145,400	$ -	$ -	$ -	$ -	$ -	$ 150,090	$ -
2023	$ 1,385,234	$ -	$ 150,861	$ -	$ -	$ -	$ -	$ -	$ 155,727	$ -
2024	$ 1,437,261	$ -	$ 156,527	$ -	$ -	$ -	$ -	$ -	$ 161,576	$ -
2025	$ 971,862	$ -	$ 162,406	$ -	$ -	$ -	$ -	$ -	$ 167,645	$ -
2026	$ 834,423	$ -	$ 168,506	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 865,763	$ -	$ 174,835	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 898,280	$ -	$ 181,401	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 932,018	$ -	$ 188,214	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hier

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Market Price Revenues									
Energy & Capacity									
1999	$ 149,543	$ 150,948	$ 18,847	$ 63,016	$ 63,419	$ 63,751	$ 64,707	$ 11,968	$ 17,733
2000	$ 170,363	$ 171,403	$ 30,564	$ 71,629	$ 72,182	$ 72,486	$ 73,444	$ -	$ 28,159
2001	$ 202,271	$ 202,906	$ 50,924	$ 84,885	$ 85,602	$ 85,933	$ 86,891	$ -	$ 46,627
2002	$ 211,420	$ 211,605	$ 52,969	$ 88,568	$ 89,466	$ 89,663	$ 90,617	$ -	$ 47,728
2003	$ 221,016	$ 220,702	$ 55,183	$ 92,423	$ 93,517	$ 93,566	$ 94,514	$ -	$ 48,855
2004	$ 231,084	$ 230,220	$ 57,590	$ 96,459	$ 97,768	$ 97,653	$ 98,592	$ -	$ 50,014
2005	$ 240,303	$ 239,105	$ 60,238	$ 100,279	$ 101,629	$ 101,444	$ 102,683	$ -	$ 50,992
2006	$ 249,909	$ 248,347	$ 63,138	$ 104,258	$ 105,651	$ 105,389	$ 106,953	$ -	$ 52,005
2007	$ 259,917	$ 257,962	$ 66,324	$ 108,403	$ 109,839	$ 109,494	$ 111,410	$ -	$ 53,052
2008	$ 270,345	$ 267,965	$ 69,837	$ 112,720	$ 114,200	$ 113,766	$ 116,063	$ -	$ 54,134
2009	$ 281,211	$ 278,372	$ 73,723	$ 117,216	$ 118,743	$ 118,213	$ 120,921	$ -	$ 55,253
2010	$ 292,913	$ 289,941	$ 75,987	$ 122,089	$ 123,688	$ 123,123	$ 125,958	$ -	$ 56,642
2011	$ 305,134	$ 302,022	$ 78,327	$ 127,179	$ 128,852	$ 128,251	$ 131,219	$ -	$ 58,067
2012	$ 317,891	$ 314,633	$ 80,747	$ 132,491	$ 134,242	$ 133,603	$ 136,711	$ -	$ 59,527
2013	$ 331,207	$ 327,797	$ 83,249	$ 138,036	$ 139,870	$ 139,190	$ 142,444	$ -	$ 61,025
2014	$ 345,110	$ 341,538	$ 85,836	$ -	$ 145,745	$ 145,022	$ 148,430	$ -	$ 62,560
2015	$ 359,623	$ 355,884	$ 88,511	$ -	$ -	$ 151,111	$ 154,678	$ -	$ -
2016	$ 373,305	$ 369,424	$ 91,878	$ -	$ -	$ 156,860	$ 160,563	$ -	$ -
2017	$ 386,986	$ 382,963	$ 95,246	$ -	$ -	$ -	$ 166,447	$ -	$ -
2018	$ 400,667	$ 396,502	$ 98,613	$ -	$ -	$ -	$ 172,332	$ -	$ -
2019	$ 416,303	$ 411,975	$ 102,461	$ -	$ -	$ -	$ 179,057	$ -	$ -
2020	$ 431,939	$ 427,448	$ 106,310	$ -	$ -	$ -	$ 185,782	$ -	$ -
2021	$ 448,162	$ 443,503	$ 110,302	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 464,994	$ 460,160	$ 114,445	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 482,459	$ 477,443	$ 118,744	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 500,580	$ 495,375	$ 123,204	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 513,981	$ 127,831	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 533,285	$ 132,632	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 553,315	$ 137,614	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 574,096	$ 142,782	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 595,659	$ 148,145	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Fuel Rate ($/MWhr)										
1999	$ 8.37	$ 11.06	$ 0.00	$ 14.73	$ 27.01	$ 29.71	$ 14.04	$ 14.46	$ 31.06	$ 10.59
2000	$ 7.95	$ 11.37	$ 0.00	$ 15.63	$ -	$ -	$ 14.90	$ 15.33	$ 33.14	$ 11.47
2001	$ 8.20	$ 11.68	$ 0.00	$ 16.58	$ -	$ -	$ 15.82	$ 16.24	$ 35.37	$ 12.43
2002	$ 8.51	$ 12.00	$ 0.00	$ 17.59	$ -	$ -	$ 16.80	$ 17.21	$ 37.74	$ 13.46
2003	$ 8.84	$ 12.33	$ 0.00	$ 18.67	$ -	$ -	$ 17.83	$ 18.23	$ 40.28	$ 14.58
2004	$ 9.19	$ 12.67	$ 0.00	$ 19.81	$ -	$ -	$ 18.93	$ 19.32	$ 42.98	$ 15.80
2005	$ 9.22	$ 12.98	$ 0.00	$ -	$ -	$ -	$ 19.58	$ 20.01	$ 45.56	$ 16.47
2006	$ 9.59	$ 13.29	$ 0.00	$ -	$ -	$ -	$ 20.25	$ 20.72	$ 48.29	$ 17.17
2007	$ 9.98	$ 13.60	$ 0.00	$ -	$ -	$ -	$ 20.95	$ 21.45	$ 51.18	$ 17.90
2008	$ 10.39	$ 13.93	$ 0.00	$ -	$ -	$ -	$ 21.67	$ 22.21	$ 54.25	$ 18.66
2009	$ 10.80	$ 14.26	$ 0.00	$ -	$ -	$ -	$ 22.42	$ 23.00	$ 57.51	$ 19.45
2010	$ 11.19	$ 14.65	$ 0.00	$ -	$ -	$ -	$ 23.02	$ 23.62	$ 60.44	$ 19.98
2011	$ 10.04	$ 15.04	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 63.52	$ 20.52
2012	$ 10.41	$ 15.45	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 66.76	$ 21.07
2013	$ 10.80	$ 15.87	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 70.17	$ 21.64
2014	$ 11.47	$ 16.29	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 73.74	$ 22.22
2015	$ 12.05	$ 16.73	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 77.50	$ 22.82
2016	$ 12.51	$ 17.37	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 80.45	$ 23.69
2017	$ 13.42	$ 18.01	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 83.40	$ 24.56
2018	$ 13.89	$ 18.64	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 86.35	$ 25.43
2019	$ 12.98	$ 19.37	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 89.72	$ -
2020	$ 13.46	$ 20.10	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 93.09	$ -
2021	$ 14.49	$ 20.85	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 96.59	$ -
2022	$ 13.97	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 100.21	$ -
2023	$ 14.49	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 103.98	$ -
2024	$ 15.04	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 107.88	$ -
2025	$ 19.67	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ 111.93	$ -
2026	$ 11.59	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 12.02	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 12.47	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 12.94	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hier

(000)	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Fuel Rate ($/MWhr)									
1999	$ 4.46	$ 4.46	$ 24.72	$ 5.84	$ 5.84	$ 5.84	$ 5.84	$ 29.16	$ 252.55
2000	$ 4.42	$ 4.42	$ 25.95	$ 5.74	$ 5.74	$ 5.74	$ 5.74	$ -	$ 267.39
2001	$ 4.43	$ 4.43	$ 27.25	$ 5.68	$ 5.68	$ 5.68	$ 5.68	$ -	$ 283.11
2002	$ 4.50	$ 4.50	$ 28.60	$ 5.72	$ 5.72	$ 5.72	$ 5.72	$ -	$ 299.75
2003	$ 4.55	$ 4.55	$ 30.03	$ 5.75	$ 5.75	$ 5.75	$ 5.75	$ -	$ 317.37
2004	$ 4.60	$ 4.60	$ 31.52	$ 5.83	$ 5.83	$ 5.83	$ 5.83	$ -	$ 336.03
2005	$ 4.68	$ 4.68	$ 32.54	$ 5.95	$ 5.95	$ 5.95	$ 5.95	$ -	$ 356.18
2006	$ 4.87	$ 4.87	$ 33.60	$ 6.17	$ 6.17	$ 6.17	$ 6.17	$ -	$ 377.54
2007	$ 5.06	$ 5.06	$ 34.69	$ 6.38	$ 6.38	$ 6.38	$ 6.38	$ -	$ 400.18
2008	$ 5.26	$ 5.26	$ 35.82	$ 6.61	$ 6.61	$ 6.61	$ 6.61	$ -	$ 424.18
2009	$ 5.44	$ 5.44	$ 36.98	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ -	$ 449.62
2010	$ 5.66	$ 5.66	$ 38.72	$ 7.12	$ 7.12	$ 7.12	$ 7.12	$ -	$ 472.55
2011	$ 5.84	$ 5.84	$ 40.53	$ 7.35	$ 7.35	$ 7.35	$ 7.35	$ -	$ 496.65
2012	$ 6.06	$ 6.06	$ 42.44	$ 7.62	$ 7.62	$ 7.62	$ 7.62	$ -	$ 521.98
2013	$ 6.28	$ 6.28	$ 44.43	$ 7.90	$ 7.90	$ 7.90	$ 7.90	$ -	$ 548.60
2014	$ 6.50	$ 6.50	$ 46.52	$ -	$ 8.17	$ 8.17	$ 8.17	$ -	$ 576.58
2015	$ 6.72	$ 6.72	$ 48.71	$ -	$ -	$ 8.45	$ 8.45	$ -	$ -
2016	$ 6.98	$ 6.98	$ 50.56	$ -	$ -	$ 8.77	$ 8.77	$ -	$ -
2017	$ 7.23	$ 7.23	$ 52.42	$ -	$ -	$ -	$ 9.09	$ -	$ -
2018	$ 7.49	$ 7.49	$ 54.27	$ -	$ -	$ -	$ 9.41	$ -	$ -
2019	$ 7.78	$ 7.78	$ 56.39	$ -	$ -	$ -	$ 9.78	$ -	$ -
2020	$ 8.07	$ 8.07	$ 58.50	$ -	$ -	$ -	$ 10.15	$ -	$ -
2021	$ 8.38	$ 8.38	$ 60.70	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 8.69	$ 8.69	$ 62.98	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 9.02	$ 9.02	$ 65.35	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 9.36	$ 9.36	$ 67.80	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 9.71	$ 70.35	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 10.07	$ 72.99	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 10.45	$ 75.73	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 10.84	$ 78.58	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 11.25	$ 81.53	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Fuel Cost	*(generation x fuel rate) (000's)*									
1999	$ 326,925	$ 29,106	$ 2	$ 14,740	$ 11,471	$ 13,208	$ 28,109	$ 29,363	$ 29,576	$ 28,140
2000	$ 301,047	$ 29,929	$ 2	$ 15,340	$ -	$ -	$ 29,646	$ 30,728	$ 31,197	$ 30,503
2001	$ 310,172	$ 30,775	$ 2	$ 15,964	$ -	$ -	$ 31,266	$ 32,157	$ 32,907	$ 33,064
2002	$ 321,792	$ 31,646	$ 2	$ 16,614	$ -	$ -	$ 32,976	$ 33,651	$ 34,710	$ 35,840
2003	$ 333,830	$ 32,541	$ 2	$ 17,290	$ -	$ -	$ 34,778	$ 35,216	$ 36,612	$ 38,850
2004	$ 347,061	$ 33,461	$ 2	$ 17,994	$ -	$ -	$ 36,680	$ 36,853	$ 38,618	$ 42,112
2005	$ 340,072	$ 34,240	$ 2	$ -	$ -	$ -	$ 38,197	$ 38,691	$ 40,175	$ 43,874
2006	$ 354,121	$ 35,036	$ 2	$ -	$ -	$ -	$ 39,777	$ 40,620	$ 41,795	$ 45,710
2007	$ 368,804	$ 35,852	$ 2	$ -	$ -	$ -	$ 41,422	$ 42,646	$ 43,480	$ 47,623
2008	$ 384,376	$ 36,686	$ 2	$ -	$ -	$ -	$ 43,136	$ 44,773	$ 45,232	$ 49,617
2009	$ 400,388	$ 37,540	$ 2	$ -	$ -	$ -	$ 44,920	$ 47,007	$ 47,056	$ 51,693
2010	$ 414,774	$ 38,554	$ 2	$ -	$ -	$ -	$ 46,133	$ 48,276	$ 49,456	$ 53,089
2011	$ 331,496	$ 39,595	$ 2	$ -	$ -	$ -	$ -	$ -	$ 51,978	$ 54,522
2012	$ 343,884	$ 40,664	$ 2	$ -	$ -	$ -	$ -	$ -	$ 54,629	$ 55,994
2013	$ 356,530	$ 41,762	$ 2	$ -	$ -	$ -	$ -	$ -	$ 57,415	$ 57,506
2014	$ 346,461	$ 42,889	$ 2	$ -	$ -	$ -	$ -	$ -	$ 60,343	$ 59,059
2015	$ 329,986	$ 44,047	$ 2	$ -	$ -	$ -	$ -	$ -	$ 63,421	$ 60,654
2016	$ 342,540	$ 45,723	$ 2	$ -	$ -	$ -	$ -	$ -	$ 65,833	$ 62,961
2017	$ 329,138	$ 47,399	$ 2	$ -	$ -	$ -	$ -	$ -	$ 68,246	$ 65,268
2018	$ 340,775	$ 49,075	$ 2	$ -	$ -	$ -	$ -	$ -	$ 70,659	$ 67,576
2019	$ 283,860	$ 50,990	$ 2	$ -	$ -	$ -	$ -	$ -	$ 73,416	$ -
2020	$ 294,521	$ 52,905	$ 2	$ -	$ -	$ -	$ -	$ -	$ 76,174	$ -
2021	$ 275,524	$ 54,892	$ 2	$ -	$ -	$ -	$ -	$ -	$ 79,035	$ -
2022	$ 228,919	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ 82,003	$ -
2023	$ 237,517	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ 85,083	$ -
2024	$ 246,438	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ 88,279	$ -
2025	$ 190,694	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ 91,594	$ -
2026	$ 102,822	$ -	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 106,683	$ -	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 110,690	$ -	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 114,848	$ -	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hier

(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Fuel Cost									
1999	$ 29,835	$ 29,835	$ 4,456	$ 16,401	$ 16,401	$ 16,651	$ 16,651	$ 8,670	$ 4,309
2000	$ 29,602	$ 29,602	$ 5,090	$ 16,140	$ 16,140	$ 16,386	$ 16,386	$ -	$ 4,356
2001	$ 29,718	$ 29,718	$ 5,813	$ 15,975	$ 15,975	$ 16,218	$ 16,218	$ -	$ 4,404
2002	$ 30,182	$ 30,182	$ 6,639	$ 16,102	$ 16,102	$ 16,347	$ 16,347	$ -	$ 4,453
2003	$ 30,546	$ 30,546	$ 7,583	$ 16,218	$ 16,218	$ 16,464	$ 16,464	$ -	$ 4,502
2004	$ 30,905	$ 30,905	$ 8,661	$ 16,455	$ 16,455	$ 16,705	$ 16,705	$ -	$ 4,552
2005	$ 31,421	$ 31,421	$ 10,017	$ 16,783	$ 16,783	$ 17,038	$ 17,038	$ -	$ 4,393
2006	$ 32,675	$ 32,675	$ 11,585	$ 17,369	$ 17,369	$ 17,633	$ 17,633	$ -	$ 4,240
2007	$ 33,928	$ 33,928	$ 13,399	$ 17,971	$ 17,971	$ 18,244	$ 18,244	$ -	$ 4,092
2008	$ 35,246	$ 35,246	$ 15,497	$ 18,606	$ 18,606	$ 18,889	$ 18,889	$ -	$ 3,950
2009	$ 36,445	$ 36,445	$ 17,923	$ 19,240	$ 19,240	$ 19,532	$ 19,532	$ -	$ 3,812
2010	$ 37,913	$ 37,913	$ 18,765	$ 20,015	$ 20,015	$ 20,319	$ 20,319	$ -	$ 4,007
2011	$ 39,136	$ 39,136	$ 19,647	$ 20,660	$ 20,660	$ 20,974	$ 20,974	$ -	$ 4,211
2012	$ 40,604	$ 40,604	$ 20,570	$ 21,435	$ 21,435	$ 21,761	$ 21,761	$ -	$ 4,426
2013	$ 42,071	$ 42,071	$ 21,537	$ 22,210	$ 22,210	$ 22,547	$ 22,547	$ -	$ 4,651
2014	$ 43,539	$ 43,539	$ 22,550	$ -	$ 22,985	$ 23,334	$ 23,334	$ -	$ 4,889
2015	$ 45,006	$ 45,006	$ 23,609	$ -	$ -	$ 24,121	$ 24,121	$ -	$ -
2016	$ 46,719	$ 46,719	$ 24,508	$ -	$ -	$ 25,038	$ 25,038	$ -	$ -
2017	$ 48,431	$ 48,431	$ 25,406	$ -	$ -	$ -	$ 25,956	$ -	$ -
2018	$ 50,143	$ 50,143	$ 26,304	$ -	$ -	$ -	$ 26,873	$ -	$ -
2019	$ 52,100	$ 52,100	$ 27,330	$ -	$ -	$ -	$ 27,922	$ -	$ -
2020	$ 54,056	$ 54,056	$ 28,357	$ -	$ -	$ -	$ 28,971	$ -	$ -
2021	$ 56,087	$ 56,087	$ 29,422	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 58,193	$ 58,193	$ 30,527	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 60,379	$ 60,379	$ 31,674	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 62,647	$ 62,647	$ 32,863	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 65,000	$ 34,097	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 67,441	$ 35,378	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 69,974	$ 36,707	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 72,602	$ 38,086	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 75,329	$ 39,516	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Operating & Maintenance Projection										
1999	$ 512,875	$ 8,047	$ 10,604	$ 11,777	$ 4,890	$ 5,892	$ 22,024	$ 20,476	$ 10,792	$ 7,138
2000	$ 512,099	$ 8,268	$ 10,896	$ 12,008	$ -	$ -	$ 22,563	$ 20,906	$ 11,074	$ 7,335
2001	$ 525,071	$ 8,490	$ 11,188	$ 12,237	$ -	$ -	$ 23,100	$ 21,331	$ 11,356	$ 7,531
2002	$ 542,453	$ 8,785	$ 11,577	$ 12,568	$ -	$ -	$ 23,834	$ 21,934	$ 11,735	$ 7,793
2003	$ 561,509	$ 9,006	$ 11,869	$ 14,343	$ -	$ -	$ 25,325	$ 23,820	$ 13,103	$ 7,990
2004	$ 578,994	$ 9,302	$ 12,258	$ 14,687	$ -	$ -	$ 26,076	$ 24,439	$ 13,503	$ 8,252
2005	$ 581,937	$ 9,597	$ 12,647	$ -	$ -	$ -	$ 26,987	$ 25,400	$ 13,885	$ 8,514
2006	$ 603,940	$ 9,966	$ 13,134	$ -	$ -	$ -	$ 28,113	$ 26,571	$ 14,370	$ 8,841
2007	$ 621,615	$ 10,261	$ 13,523	$ -	$ -	$ -	$ 29,036	$ 27,562	$ 14,747	$ 9,103
2008	$ 643,670	$ 10,630	$ 14,009	$ -	$ -	$ -	$ 30,175	$ 28,767	$ 15,227	$ 9,430
2009	$ 665,753	$ 10,999	$ 14,496	$ -	$ -	$ -	$ 31,321	$ 29,990	$ 15,706	$ 9,758
2010	$ 691,901	$ 11,442	$ 15,080	$ -	$ -	$ -	$ 32,582	$ 31,197	$ 16,338	$ 10,151
2011	$ 647,853	$ 11,812	$ 15,566	$ -	$ -	$ -	$ -	$ -	$ 16,865	$ 10,478
2012	$ 671,532	$ 12,254	$ 16,150	$ -	$ -	$ -	$ -	$ -	$ 17,498	$ 10,871
2013	$ 695,210	$ 12,697	$ 16,733	$ -	$ -	$ -	$ -	$ -	$ 18,130	$ 11,264
2014	$ 657,768	$ 13,140	$ 17,317	$ -	$ -	$ -	$ -	$ -	$ 18,762	$ 11,657
2015	$ 616,187	$ 13,583	$ 17,901	$ -	$ -	$ -	$ -	$ -	$ 19,395	$ 12,050
2016	$ 639,005	$ 14,100	$ 18,582	$ -	$ -	$ -	$ -	$ -	$ 20,133	$ 12,508
2017	$ 541,511	$ 14,617	$ 19,263	$ -	$ -	$ -	$ -	$ -	$ 20,871	$ 12,967
2018	$ 560,076	$ 15,134	$ 19,944	$ -	$ -	$ -	$ -	$ -	$ 21,608	$ 13,425
2019	$ 567,343	$ 15,724	$ 20,722	$ -	$ -	$ -	$ -	$ -	$ 22,452	$ -
2020	$ 588,036	$ 16,315	$ 21,501	$ -	$ -	$ -	$ -	$ -	$ 23,295	$ -
2021	$ 470,175	$ 16,927	$ 22,308	$ -	$ -	$ -	$ -	$ -	$ 24,170	$ -
2022	$ 444,284	$ -	$ 23,146	$ -	$ -	$ -	$ -	$ -	$ 25,078	$ -
2023	$ 460,354	$ -	$ 24,015	$ -	$ -	$ -	$ -	$ -	$ 26,020	$ -
2024	$ 477,029	$ -	$ 24,917	$ -	$ -	$ -	$ -	$ -	$ 26,997	$ -
2025	$ 284,134	$ -	$ 25,853	$ -	$ -	$ -	$ -	$ -	$ 28,011	$ -
2026	$ 265,435	$ -	$ 26,824	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 275,097	$ -	$ 27,832	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 285,121	$ -	$ 28,877	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 295,522	$ -	$ 29,961	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieron
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Operating & Maintenance Projection									
1999	$ 91,054	$ 91,054	$ 8,091	$ 37,428	$ 37,428	$ 66,232	$ 66,232	$ 2,978	$ 10,740
2000	$ 93,334	$ 93,334	$ 8,321	$ 38,458	$ 38,458	$ 68,055	$ 68,055	$ -	$ 11,032
2001	$ 95,614	$ 95,614	$ 8,553	$ 39,488	$ 39,488	$ 69,878	$ 69,878	$ -	$ 11,325
2002	$ 98,655	$ 98,655	$ 8,860	$ 40,862	$ 40,862	$ 72,309	$ 72,309	$ -	$ 11,716
2003	$ 100,935	$ 100,935	$ 9,094	$ 41,892	$ 41,892	$ 74,131	$ 74,131	$ -	$ 13,042
2004	$ 103,976	$ 103,976	$ 9,404	$ 43,265	$ 43,265	$ 76,562	$ 76,562	$ -	$ 13,467
2005	$ 107,016	$ 107,016	$ 9,721	$ 44,639	$ 44,639	$ 78,993	$ 78,993	$ -	$ 13,891
2006	$ 110,817	$ 110,817	$ 10,117	$ 46,356	$ 46,356	$ 82,031	$ 82,031	$ -	$ 14,422
2007	$ 113,857	$ 113,857	$ 10,442	$ 47,729	$ 47,729	$ 84,461	$ 84,461	$ -	$ 14,846
2008	$ 117,658	$ 117,658	$ 10,846	$ 49,446	$ 49,446	$ 87,499	$ 87,499	$ -	$ 15,377
2009	$ 121,459	$ 121,459	$ 11,256	$ 51,163	$ 51,163	$ 90,538	$ 90,538	$ -	$ 15,908
2010	$ 126,019	$ 126,019	$ 11,710	$ 53,223	$ 53,223	$ 94,183	$ 94,183	$ -	$ 16,548
2011	$ 129,820	$ 129,820	$ 12,087	$ 54,940	$ 54,940	$ 97,222	$ 97,222	$ -	$ 17,081
2012	$ 134,381	$ 134,381	$ 12,541	$ 57,000	$ 57,000	$ 100,867	$ 100,867	$ -	$ 17,721
2013	$ 138,942	$ 138,942	$ 12,994	$ 59,061	$ 59,061	$ 104,513	$ 104,513	$ -	$ 18,361
2014	$ 143,502	$ 143,502	$ 13,447	$ -	$ 61,121	$ 108,159	$ 108,159	$ -	$ 19,001
2015	$ 148,063	$ 148,063	$ 13,900	$ -	$ -	$ 111,805	$ 111,805	$ -	$ 19,622
2016	$ 153,384	$ 153,384	$ 14,429	$ -	$ -	$ 116,058	$ 116,058	$ -	$ 20,369
2017	$ 158,705	$ 158,705	$ 14,958	$ -	$ -	$ -	$ 120,312	$ -	$ 21,115
2018	$ 164,026	$ 164,026	$ 15,487	$ -	$ -	$ -	$ 124,565	$ -	$ 21,862
2019	$ 170,107	$ 170,107	$ 16,091	$ -	$ -	$ -	$ 129,426	$ -	$ 22,715
2020	$ 176,188	$ 176,188	$ 16,696	$ -	$ -	$ -	$ 134,287	$ -	$ 23,568
2021	$ 182,497	$ 182,497	$ 17,323	$ -	$ -	$ -	$ -	$ -	$ 24,453
2022	$ 189,043	$ 189,043	$ 17,973	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 195,836	$ 195,836	$ 18,648	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 202,883	$ 202,883	$ 19,349	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 210,195	$ 20,076	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 217,782	$ 20,830	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 225,653	$ 21,612	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 233,821	$ 22,424	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 242,295	$ 23,266	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Capital Expenditure Projection										
1999	$ 98,477	$ 2,054	$ 1,467	$ 1,572	$ 943	$ 1,677	$ 1,887	$ 1,887	$ 1,887	$ 2,893
2000	$ 97,634	$ 2,111	$ 1,508	$ 1,615	$ -	$ -	$ 1,938	$ 1,938	$ 1,938	$ 2,972
2001	$ 100,249	$ 2,167	$ 1,548	$ 1,659	$ -	$ -	$ 1,990	$ 1,990	$ 1,990	$ 3,052
2002	$ 103,736	$ 2,243	$ 1,602	$ 1,716	$ -	$ -	$ 2,060	$ 2,060	$ 2,060	$ 3,158
2003	$ 106,351	$ 2,299	$ 1,642	$ 1,760	$ -	$ -	$ 2,112	$ 2,112	$ 2,112	$ 3,238
2004	$ 109,838	$ 2,375	$ 1,696	$ 1,817	$ -	$ -	$ 2,181	$ 2,181	$ 2,181	$ 3,344
2005	$ 111,450	$ 2,450	$ 1,750	$ -	$ -	$ -	$ 2,250	$ 2,250	$ 2,250	$ 3,450
2006	$ 115,737	$ 2,544	$ 1,817	$ -	$ -	$ -	$ 2,337	$ 2,337	$ 2,337	$ 3,583
2007	$ 119,166	$ 2,620	$ 1,871	$ -	$ -	$ -	$ 2,406	$ 2,406	$ 2,406	$ 3,689
2008	$ 123,452	$ 2,714	$ 1,938	$ -	$ -	$ -	$ 2,492	$ 2,492	$ 2,492	$ 3,822
2009	$ 127,739	$ 2,808	$ 2,006	$ -	$ -	$ -	$ 2,579	$ 2,579	$ 2,579	$ 3,954
2010	$ 132,883	$ 2,921	$ 2,087	$ -	$ -	$ -	$ 2,683	$ 2,683	$ 2,683	$ 4,113
2011	$ 131,631	$ 3,015	$ 2,154	$ -	$ -	$ -	$ -	$ -	$ 2,769	$ 4,246
2012	$ 136,567	$ 3,128	$ 2,235	$ -	$ -	$ -	$ -	$ -	$ 2,873	$ 4,405
2013	$ 141,503	$ 3,242	$ 2,315	$ -	$ -	$ -	$ -	$ -	$ 2,977	$ 4,565
2014	$ 133,531	$ 3,355	$ 2,396	$ -	$ -	$ -	$ -	$ -	$ 3,081	$ 4,724
2015	$ 123,096	$ 3,468	$ 2,477	$ -	$ -	$ -	$ -	$ -	$ 3,185	$ 4,883
2016	$ 127,779	$ 3,600	$ 2,571	$ -	$ -	$ -	$ -	$ -	$ 3,306	$ 5,069
2017	$ 118,103	$ 3,732	$ 2,665	$ -	$ -	$ -	$ -	$ -	$ 3,427	$ 5,255
2018	$ 122,279	$ 3,863	$ 2,760	$ -	$ -	$ -	$ -	$ -	$ 3,548	$ 5,440
2019	$ 121,398	$ 4,014	$ 2,867	$ -	$ -	$ -	$ -	$ -	$ 3,687	$ -
2020	$ 125,957	$ 4,165	$ 2,975	$ -	$ -	$ -	$ -	$ -	$ 3,825	$ -
2021	$ 114,059	$ 4,321	$ 3,087	$ -	$ -	$ -	$ -	$ -	$ 3,969	$ -
2022	$ 113,860	$ -	$ 3,203	$ -	$ -	$ -	$ -	$ -	$ 4,118	$ -
2023	$ 118,136	$ -	$ 3,323	$ -	$ -	$ -	$ -	$ -	$ 4,272	$ -
2024	$ 122,573	$ -	$ 3,448	$ -	$ -	$ -	$ -	$ -	$ 4,433	$ -
2025	$ 69,082	$ -	$ 3,577	$ -	$ -	$ -	$ -	$ -	$ 4,599	$ -
2026	$ 66,905	$ -	$ 3,712	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 69,417	$ -	$ 3,851	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 72,025	$ -	$ 3,996	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 74,730	$ -	$ 4,146	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieron
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Capital Expenditure Projection									
1999	$ 23,829	$ 23,829	$ 1,153	$ 7,905	$ 7,905	$ 7,905	$ 7,905	$ 838	$ 943
2000	$ 24,485	$ 24,485	$ 1,185	$ 8,122	$ 8,122	$ 8,122	$ 8,122	$ -	$ 969
2001	$ 25,141	$ 25,141	$ 1,216	$ 8,340	$ 8,340	$ 8,340	$ 8,340	$ -	$ 995
2002	$ 26,015	$ 26,015	$ 1,259	$ 8,630	$ 8,630	$ 8,630	$ 8,630	$ -	$ 1,030
2003	$ 26,671	$ 26,671	$ 1,290	$ 8,847	$ 8,847	$ 8,847	$ 8,847	$ -	$ 1,056
2004	$ 27,546	$ 27,546	$ 1,333	$ 9,137	$ 9,137	$ 9,137	$ 9,137	$ -	$ 1,090
2005	$ 28,420	$ 28,420	$ 1,375	$ 9,428	$ 9,428	$ 9,428	$ 9,428	$ -	$ 1,125
2006	$ 29,513	$ 29,513	$ 1,428	$ 9,790	$ 9,790	$ 9,790	$ 9,790	$ -	$ 1,168
2007	$ 30,388	$ 30,388	$ 1,470	$ 10,080	$ 10,080	$ 10,080	$ 10,080	$ -	$ 1,203
2008	$ 31,481	$ 31,481	$ 1,523	$ 10,443	$ 10,443	$ 10,443	$ 10,443	$ -	$ 1,246
2009	$ 32,574	$ 32,574	$ 1,576	$ 10,805	$ 10,805	$ 10,805	$ 10,805	$ -	$ 1,289
2010	$ 33,885	$ 33,885	$ 1,639	$ 11,240	$ 11,240	$ 11,240	$ 11,240	$ -	$ 1,341
2011	$ 34,978	$ 34,978	$ 1,692	$ 11,603	$ 11,603	$ 11,603	$ 11,603	$ -	$ 1,385
2012	$ 36,290	$ 36,290	$ 1,756	$ 12,038	$ 12,038	$ 12,038	$ 12,038	$ -	$ 1,437
2013	$ 37,602	$ 37,602	$ 1,819	$ 12,473	$ 12,473	$ 12,473	$ 12,473	$ -	$ 1,488
2014	$ 38,914	$ 38,914	$ 1,883	$ -	$ 12,908	$ 12,908	$ 12,908	$ -	$ 1,540
2015	$ 40,225	$ 40,225	$ 1,946	$ -	$ -	$ 13,344	$ 13,344	$ -	$ -
2016	$ 41,756	$ 41,756	$ 2,020	$ -	$ -	$ 13,851	$ 13,851	$ -	$ -
2017	$ 43,286	$ 43,286	$ 2,094	$ -	$ -	$ -	$ 14,359	$ -	$ -
2018	$ 44,816	$ 44,816	$ 2,168	$ -	$ -	$ -	$ 14,866	$ -	$ -
2019	$ 46,565	$ 46,565	$ 2,253	$ -	$ -	$ -	$ 15,447	$ -	$ -
2020	$ 48,314	$ 48,314	$ 2,338	$ -	$ -	$ -	$ 16,027	$ -	$ -
2021	$ 50,129	$ 50,129	$ 2,425	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 52,011	$ 52,011	$ 2,516	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 53,965	$ 53,965	$ 2,611	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 55,992	$ 55,992	$ 2,709	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 58,095	$ 2,811	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 60,277	$ 2,916	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 62,541	$ 3,026	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 64,889	$ 3,139	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 67,327	$ 3,257	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Administrative & General Projection										
Allocated to Stations*										
1999	$ 64,014	$ -	$ 1,791	$ 1,353	$ 769	$ 958	$ 2,317	$ 1,906	$ 1,819	$ -
2000	$ 63,443	$ -	$ 1,840	$ 1,390	$ -	$ -	$ 2,381	$ 1,959	$ 1,869	$ -
2001	$ 65,143	$ -	$ 1,889	$ 1,427	$ -	$ -	$ 2,445	$ 2,011	$ 1,919	$ -
2002	$ 67,409	$ -	$ 1,955	$ 1,477	$ -	$ -	$ 2,530	$ 2,081	$ 1,986	$ -
2003	$ 69,108	$ -	$ 2,004	$ 1,514	$ -	$ -	$ 2,594	$ 2,134	$ 2,036	$ -
2004	$ 71,374	$ -	$ 2,070	$ 1,564	$ -	$ -	$ 2,679	$ 2,204	$ 2,103	$ -
2005	$ 72,026	$ -	$ 2,136	$ -	$ -	$ -	$ 2,764	$ 2,274	$ 2,170	$ -
2006	$ 74,796	$ -	$ 2,218	$ -	$ -	$ -	$ 2,870	$ 2,361	$ 2,253	$ -
2007	$ 77,012	$ -	$ 2,283	$ -	$ -	$ -	$ 2,955	$ 2,431	$ 2,320	$ -
2008	$ 79,783	$ -	$ 2,366	$ -	$ -	$ -	$ 3,061	$ 2,518	$ 2,403	$ -
2009	$ 82,553	$ -	$ 2,448	$ -	$ -	$ -	$ 3,168	$ 2,606	$ 2,487	$ -
2010	$ 85,877	$ -	$ 2,546	$ -	$ -	$ -	$ 3,295	$ 2,711	$ 2,587	$ -
2011	$ 82,448	$ -	$ 2,628	$ -	$ -	$ -	$ -	$ -	$ 2,670	$ -
2012	$ 85,540	$ -	$ 2,727	$ -	$ -	$ -	$ -	$ -	$ 2,770	$ -
2013	$ 88,631	$ -	$ 2,825	$ -	$ -	$ -	$ -	$ -	$ 2,871	$ -
2014	$ 80,056	$ -	$ 2,924	$ -	$ -	$ -	$ -	$ -	$ 2,971	$ -
2015	$ 67,610	$ -	$ 3,023	$ -	$ -	$ -	$ -	$ -	$ 3,071	$ -
2016	$ 70,182	$ -	$ 3,138	$ -	$ -	$ -	$ -	$ -	$ 3,188	$ -
2017	$ 72,754	$ -	$ 3,253	$ -	$ -	$ -	$ -	$ -	$ 3,305	$ -
2018	$ 75,326	$ -	$ 3,368	$ -	$ -	$ -	$ -	$ -	$ 3,421	$ -
2019	$ 78,266	$ -	$ 3,499	$ -	$ -	$ -	$ -	$ -	$ 3,555	$ -
2020	$ 81,205	$ -	$ 3,630	$ -	$ -	$ -	$ -	$ -	$ 3,688	$ -
2021	$ 84,255	$ -	$ 3,767	$ -	$ -	$ -	$ -	$ -	$ 3,827	$ -
2022	$ 87,420	$ -	$ 3,908	$ -	$ -	$ -	$ -	$ -	$ 3,971	$ -
2023	$ 90,703	$ -	$ 4,055	$ -	$ -	$ -	$ -	$ -	$ 4,120	$ -
2024	$ 94,110	$ -	$ 4,207	$ -	$ -	$ -	$ -	$ -	$ 4,274	$ -
2025	$ 55,085	$ -	$ 4,365	$ -	$ -	$ -	$ -	$ -	$ 4,435	$ -
2026	$ 52,553	$ -	$ 4,529	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 54,526	$ -	$ 4,699	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 56,574	$ -	$ 4,876	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 58,699	$ -	$ 5,059	$ -	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

Putnam, Hayes & Bartlett - Utilizing W. Hieron
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Administrative & General Projection									
Allocated to Stations*									
1999	$ 17,457	$ 17,457	$ 1,528	$ 7,145	$ 7,145	$ -	$ -	$ 543	$ 1,827
2000	$ 17,937	$ 17,937	$ 1,570	$ 7,341	$ 7,341	$ -	$ -	$ -	$ 1,877
2001	$ 18,418	$ 18,418	$ 1,612	$ 7,538	$ 7,538	$ -	$ -	$ -	$ 1,927
2002	$ 19,058	$ 19,058	$ 1,668	$ 7,800	$ 7,800	$ -	$ -	$ -	$ 1,994
2003	$ 19,539	$ 19,539	$ 1,711	$ 7,997	$ 7,997	$ -	$ -	$ -	$ 2,045
2004	$ 20,179	$ 20,179	$ 1,767	$ 8,259	$ 8,259	$ -	$ -	$ -	$ 2,112
2005	$ 20,820	$ 20,820	$ 1,823	$ 8,521	$ 8,521	$ -	$ -	$ -	$ 2,179
2006	$ 21,621	$ 21,621	$ 1,893	$ 8,849	$ 8,849	$ -	$ -	$ -	$ 2,263
2007	$ 22,261	$ 22,261	$ 1,949	$ 9,111	$ 9,111	$ -	$ -	$ -	$ 2,330
2008	$ 23,062	$ 23,062	$ 2,019	$ 9,439	$ 9,439	$ -	$ -	$ -	$ 2,413
2009	$ 23,863	$ 23,863	$ 2,089	$ 9,767	$ 9,767	$ -	$ -	$ -	$ 2,497
2010	$ 24,824	$ 24,824	$ 2,173	$ 10,160	$ 10,160	$ -	$ -	$ -	$ 2,598
2011	$ 25,625	$ 25,625	$ 2,243	$ 10,488	$ 10,488	$ -	$ -	$ -	$ 2,682
2012	$ 26,585	$ 26,585	$ 2,327	$ 10,881	$ 10,881	$ -	$ -	$ -	$ 2,782
2013	$ 27,546	$ 27,546	$ 2,412	$ 11,274	$ 11,274	$ -	$ -	$ -	$ 2,883
2014	$ 28,507	$ 28,507	$ 2,496	$ -	-$ 11,667	$ -	$ -	$ -	$ 2,983
2015	$ 29,468	$ 29,468	$ 2,580	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ 30,589	$ 30,589	$ 2,678	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ 31,710	$ 31,710	$ 2,776	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ 32,831	$ 32,831	$ 2,874	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ 34,113	$ 34,113	$ 2,986	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ 35,394	$ 35,394	$ 3,099	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ 36,723	$ 36,723	$ 3,215	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 38,102	$ 38,102	$ 3,336	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 39,534	$ 39,534	$ 3,461	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 41,018	$ 41,018	$ 3,591	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 42,559	$ 3,726	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 44,157	$ 3,866	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 45,816	$ 4,011	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 47,537	$ 4,162	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 49,322	$ 4,318	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Other Taxes										
Allocated to Stations*										
1999	$ 104,936	$ -	$ 2,935	$ 2,218	$ 1,260	$ 1,571	$ 3,799	$ 3,125	$ 2,982	$ -
2000	$ 101,216	$ -	$ 2,935	$ 2,218	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2001	$ 101,216	$ -	$ 2,935	$ 2,218	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2002	$ 101,216	$ -	$ 2,935	$ 2,218	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2003	$ 101,216	$ -	$ 2,935	$ 2,218	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2004	$ 101,216	$ -	$ 2,935	$ 2,218	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2005	$ 98,998	$ -	$ 2,935	$ -	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2006	$ 98,998	$ -	$ 2,935	$ -	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2007	$ 98,998	$ -	$ 2,935	$ -	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2008	$ 98,998	$ -	$ 2,935	$ -	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2009	$ 98,998	$ -	$ 2,935	$ -	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2010	$ 98,998	$ -	$ 2,935	$ -	$ -	$ -	$ 3,799	$ 3,125	$ 2,982	$ -
2011	$ 92,074	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2012	$ 92,074	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2013	$ 92,074	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2014	$ 80,362	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2015	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2016	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2017	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2018	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2019	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2020	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2021	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2022	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2023	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2024	$ 65,655	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2025	$ 37,039	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ 2,982	$ -
2026	$ 34,057	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 34,057	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 34,057	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 34,057	$ -	$ 2,935	$ -	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

Putnam, Hayes & Bartlett - Utilizing W. Hieron
(000)

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
Other Taxes									
Allocated to Stations*									
1999	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ 890	$ 2,995
2000	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2001	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2002	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2003	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2004	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2005	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2006	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2007	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2008	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2009	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2010	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2011	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2012	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2013	$ 28,616	$ 28,616	$ 2,505	$ 11,712	$ 11,712	$ -	$ -	$ -	$ 2,995
2014	$ 28,616	$ 28,616	$ 2,505	$ -	$ 11,712	$ -	$ -	$ -	$ 2,995
2015	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 28,616	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 28,616	$ 2,505	$ -	$ -	$ -	$ -	$ -	$ -

*Conemaugh, Keystone & Salem do not receive allocated A&G and Taxes as these amounts are already included in their base O&M.

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Decommissioning										
1999	$ 31,344	$ 1,280	$ -	$ 366	$ 522	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2000	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2001	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2002	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2003	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2004	$ 30,822	$ 1,280	$ -	$ 366	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2005	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2006	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2007	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2008	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2009	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2010	$ 30,456	$ 1,280	$ -	$ -	$ -	$ -	$ 710	$ 768	$ 2,762	$ 1,298
2011	$ 28,978	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2012	$ 28,978	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2013	$ 28,978	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2014	$ 23,566	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2015	$ 18,159	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2016	$ 18,159	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2017	$ 15,533	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2018	$ 15,533	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ 1,298
2019	$ 14,235	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ -
2020	$ 14,235	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ -
2021	$ 12,296	$ 1,280	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ -
2022	$ 11,016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ -
2023	$ 11,016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ -
2024	$ 11,016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ -
2025	$ 7,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,762	$ -
2026	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieron
(000)

Decommissioning	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
1999	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2000	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2001	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2002	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2003	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2004	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2005	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2006	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2007	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2008	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2009	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2010	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2011	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2012	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2013	$ 3,116	$ 5,138	$ -	$ 5,413	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2014	$ 3,116	$ 5,138	$ -	$ -	$ 5,407	$ 2,626	$ 1,939	$ -	$ -
2015	$ 3,116	$ 5,138	$ -	$ -	$ -	$ 2,626	$ 1,939	$ -	$ -
2016	$ 3,116	$ 5,138	$ -	$ -	$ -	$ 2,626	$ 1,939	$ -	$ -
2017	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2018	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2019	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2020	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ -
2021	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ 3,116	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ 5,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hieronymus' Market Revenue Estimates

(000)

	Total	Conemaugh	Conowingo	Cromby 1	Cromby 2	Delaware	Eddystone 1	Eddystone 2	Eddystone3&4	Keystone
Required Life Extension Costs										
1999	$ 20,962	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2003	$ 87,981	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 87,981
2004	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2006	$ 97,356	$ 97,356	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2007	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ 83,462	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 83,462	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ 51,346	$ -	$ 17,115	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Putnam, Hayes & Bartlett - Utilizing W. Hleron
(000)

Required Life Extension Costs

	Limerick 1	Limerick 2	Muddy Run	P. Bottom 2	P. Bottom 3	Salem 1	Salem 2	Schuylkill	C. Turbines
1999	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,962
2000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2003	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2004	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2006	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2007	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2008	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2010	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	$ -	$ -	$ 34,231	$ -	$ -	$ -	$ -	$ -	$ -
2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2026	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2027	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2028	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

PECO Energy Company
Stranded Costs
as of December 31, 1998

Net Generating Plant & CWIP		
Less: Market Value		
($6,514,017- $2,568,014)	$	3,946,003
Regulatory Assets	$	2,632,577
NUG Contracts	$	-
Nuclear Decommissioning	$	281,790
Fossil Plant Decommissioning	$	275,116
Total	$	7,135,486
Jurisdictional Allocation @100%	$	7,135,486

Market Value of Generation Assets

PECO Analysis	$	2,646,587
ICF Kaiser	$	3,019,134
PHB	$	2,038,322
Average	$	2,568,014

EXHIBIT TPH-6

PECO ENERGY COMPANY
STRANDED COST
EARLY SECURITIZATION CLAIM

	Total Stranded @ 12-31-98 (1)	Total Stranded @ 6-30-97 (2)		Early Securitization Claim @ 6-30-97 (3)	
Stranded Generation Plant	$3,946,003	N/A		$2,435,158	(c)
Regulatory Assets:					
Carrying Charge on 50% of Limerick Common	$ 175,812	$214,881	(a)	$ 77,927	(d)
Unamortized Loss on Required Debt	179,705	206,813	(a)	75,001	(d)
Nuclear Design Basis Documentation	28,973	31,168	(a)	---	
PB/Limerick Water Chemistry Systems	6,679	7,300	(a)	---	
Limerick 1 Declaratory Order	18,301	38,872	(a)	14,097	(d)
Limerick 2 Declaratory Order	67,985	83,093	(a)	30,134	(d)
SFAS 106	114,201	126,435	(a)	45,852	(d)
Compensated Absences	18,833	20,326	(a)	---	
SFAS 109	1,693,220	1,862,819	(a)	675,550	(d)
Carrying Charge on 50% Common Sales/PE/Eddystone	17,400	18,804	(a)	6,819	(d)
Deferred Fuel	311,468	239,462	(b)	239,462	(b)
Total Regulatory Assets	$2,632,577	$2,849,973		$1,164,842	
Unfunded Nuclear Decommissioning Cost	281,790	N/A		---	
Unfunded Fossil Decommissioning Cost	275,116	N/A		---	
Total Stranded Costs	$7,135,486			$3,600,000	

(a) See Exhibit ABC-7 pg 3 of 5
(b) See Exhibit ABC-10 pg 1 of 4, present value at 6-30-97
(c) ($3,600,000 - $239,462) x 72.4633% (see Exhibit ABC-10 pg. 3 of 4)
(d) Column 2 x ($3,600,000 - $239,462) x 27.5367% (See Exhibit ABC-10 pg. 3 of 4)
$2,849,973 - $31,168 - $7,300 - $20,326 - $239,462

or

Column (2) x 36.2650%

(Note: Early securitization claim excludes Nuclear Design Basis Documentation, PB/Limerick Water Chemistry and Compensated Absences)

Exhibit TPH-7

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held February 22, 1996

Commissioners Present:

John M. Quain, Chairman
Lisa Crutchfield, Vice Chairman
John Hanger, Statement attached
David W. Rolka
Robert K. Bloom

Petition of PECO Energy Company
for a Declaratory Order Regarding
the Acceleration of Depreciation
and Amortization of Certain
Regulatory Assets Associated
With The Limerick Nuclear Station

Docket No. P-00950982

OPINION AND ORDER

BY THE COMMISSION:

Before us is the petition of PECO Energy Company ("PECO Energy" or "Company") which requests that we issue a declaratory order regarding the acceleration of depreciation and amortization of certain regulatory assets associated with the Limerick nuclear generating station.[1]

The petition was filed October 27, 1996 and, through a notice published in the Pennsylvania Bulletin (25 Pa. B. 5307 (November 25, 1995)), we invited interested parties to offer comments on the Company's petition. Comments were filed by the Philadelphia Area Industrial Energy Users Group ("Industrial Group"), Office of Consumer Advocate ("OCA"), and the Commission's Office of Trial Staff ("OTS"). PECO Energy also filed a response to these comments.

None of the commenting parties opposed the petition and, one of these, the Industrial Group supported it. Having reviewed the petition, the comments and PECO Energy's response, the Commission is of the opinion that the request before it is in the public

---

[1]The Commission has jurisdiction under Section 331(f) of the Public Utility Code, 66 Pa. C.S. § 331(f), to issue declaratory orders in its discretion to terminate a controversy or remove uncertainty.

interest and we will grant the petition for the reasons, and subject to the condition, set forth below.

Background

The Company asks us to approve a proposed change in the accounting treatment of its current depreciation of its electric plant. It wishes to utilize new life spans for various categories of electric production plant and changes in life estimates for transmission, distribution and general plant and common plant. PECO Energy is also asking to change the terminal date of the Limerick generating station for depreciation accrual purposes.

PECO Energy states that it has recently completed a new life study of the physical life of certain of its assets. It claims to have used the same basic life analysis techniques as were used in its 1988 study, on which its current depreciation rates were based. The major difference between the studies is the additional seven years of data on recorded retirement experience. PECO Energy asserts that the 1995 study supports the new life span changes regarding steam, nuclear, hydraulic production plant accounts, as well as transmission, distribution and general plant categories.

With respect to the Limerick Nuclear Station, the Company is seeking to advance the terminal date for the plant by 10 years for depreciation accrual purposes only. Such a change in the terminal date would result in a corresponding increase in the annual depreciation accruals for the plant. However, the Company states it is not seeking recognition of this change in its rates at this time. The Company is also requesting that the 10 year reduction in the terminal date apply to the amortization of costs associated with increasing the generation capacity of the Limerick units.[2]

With respect to the second item, PECO Energy is also seeking accelerated amortization of regulatory assets associated with Limerick. These include Allowance for Funds Used During Construction ("AFUDC") and deferred depreciation associated with the nuclear generating station Unit 2's share of common facilities and costs associated with the Unit 2 declaratory order.[3] With respect to the first of these items, PECO Energy states that the Commission has allowed it to recover, through its rates, the AFUDC and depreciation accrued on the 50 percent of common facilities

---

[2]The Company has increased the generation capacity of Limerick 2 from 1,055 MW to 1,115 MW and is in the process of uprating Limerick 1 from 1,055 MW to 1,106 MW. The cost of this activity is amortized.

[3]*Petition of Philadelphia Electric Co. for Declaratory Order*, 69 PA. P.U.C. 481 (Entered May 3, 1989).

associated with Limerick Unit 2.[4] The Company states that as of September 30, 1995, the unrecovered balance was $242,312,561. The current annual amortization is $7,897,000. By way of this petition, PECO Energy is proposing to amortize this cost over a nine year period commencing October 1, 1996. This results in a total annual amortization of $26,046,151.

With respect to the declaratory order costs, these are the costs of operating Unit 2 from the inception of its commercial operation in January 1990 until the recognition of its operating costs in rates. The Company states that after Limerick 2 was placed in service, but prior to our order in its last rate case (at Docket No. R-891364), certain regulatory assets associated with Unit 2 were accrued. PECO Energy states that the unrecovered balance for the Limerick 2 declaratory order costs was $90,647,125. Currently there is no annual amortization of this regulatory asset and no reflection of it in the Company's rates. The Company proposes to amortize this balance over a nine year period beginning October 1, 1996. It states that it intends to recover the costs through a future rate case.

PECO Energy also asserts that, in order to amortize a regulatory asset, there must be recognition of a revenue source. It offers three choices with respect to this recognition. It requests that the Commission deem that the revenue should be considered subsumed in existing rates from Docket No. R-891364, that the revenue had been made available through the operation of the Company's Competitive Breakthrough Strategy, or both.

The Company describes its Competitive Breakthrough Strategy as an effort to strengthen its financial position on a long-term basis to the advantage of its stockholders and customers. It argues that changes in life spans for purposes of calculating depreciation accrual on electric plant and the corresponding changes to remaining life estimates and terminal dates as well as modifications to the amortization of regulatory assets are part of this strategy. With specificity relating to Limerick, it argues that reducing the life span for depreciation purposes by 10 years allows it to recover all investment in nuclear generation plant on a company-wide basis by the end of its integrated resource planning horizon, or slightly thereafter. It maintains that this will "substantially" improve its competitive position and strengthen its financial position as well. As the electric industry becomes more competitive, PECO Energy states that it is becoming increasingly necessary for it to respond. It explains:

> Because PECO Energy is not requesting a rate increase to accompany this increased

---

[4]*Pa. P.U.C. v. Philadelphia Electric Co.*, Docket R-891364, Opinion and Order (Entered May 16, 1990).

> depreciation and amortization, it must pay for this effort through a combination of ongoing and future efforts to control expenses, limit capital expenditures, and enhance revenue. The Company does not anticipate that its efforts to limit capital expenditures and control operation and maintenance expenses will be sufficient to completely offset both future inflation and the accelerated depreciation and amortization requested in this petition. Therefore, PECO Energy will be pursuing opportunities for revenue enhancement in the emerging wholesale market, as well as other revenue opportunities, which may include innovative rate designs and the offering of new products and services, both regulated and unregulated.

PECO Energy Petition, p. 10.

The Company summarizes its requested changes by stating that the increase in annual depreciation accruals for Limerick as a result of the life study, the 10-year reduction in the terminal date for Limerick for purposes of calculating depreciation and the effect on the Limerick uprates are $71,811,695 per year. The increased amortization of certain regulatory assets associated with Limerick total $28,220,854 annually. Together this amounts to a total annual increase in depreciation and amortization of $100,032,549. The net change to depreciation and amortization of plant other than Limerick is a decrease of $10,375,180 which results in a total net annual increase in depreciation and amortization of electric and common related plant and regulatory assets of $89,657,369.

As noted above, three responses to this petition were received. The Industrial Group supports the petition calling it "an appropriate step by PECO Energy Company to become more competitive with its electricity pricing in the future." OTS states that it does not oppose the petition, but that it has "serious concerns regarding the potential ratemaking impact" of the petition should the Commission grant it. It noted that the life span of the Limerick facilities recognized for purposes of depreciation would be out of step with the station's life as useful generation property. OTS asks us to state now that we shall disallow future recognition of any additional revenue requirement as a result of shortening the life of the assets.

OCA also did not oppose the petition insofar as the Company is not seeking recognition of the proposed changes in rates at this time. However, OCA asks us to clarify that our policy would allow it, and any other party, to challenge increases in PECO Energy's

revenue requirement which might result from these changes in a future rate proceeding.

Finally, the Company responded to the comments of OTS and OCA. It supports OCA's request which would leave the Company free to seek recognition in rates of these changes in a future rate case, but allow any party to challenge the ratemaking application of those accounting changes.

Discussion

Having reviewed the petition and the comments, we believe the accounting changes requested by PECO Energy to be in the public interest and will approve them. In recent years, the electric industry has become more and more competitive. The Federal Energy Regulatory Commission is currently conducting a rulemaking proceeding which would open virtually all of the wholesale market for electricity to competition.[5] Additionally, we have found it necessary to open an investigation at Docket No. I-940032 into the role of competition in the electric power market within our own jurisdiction. The accounting changes sought by PECO Energy are ones which would be expected by an electric utility seeking to be competitive.

With respect to recognizing revenue sources for the Limerick 2 operating expenses associated with the declaratory order, we shall allow the Company to recognize the costs of the amortization to be subsumed within existing rates and to have been made available through the operation of the Company's Competitive Breakthrough Strategy. At this time it is not necessary to delineate between these revenue sources with any greater specificity. However, if the Company should seek to have this accounting change recognized in the rates which it collects from its customers in a future rate case, its existing revenues from all sources will be subject to examination.

With regard to the potential impact on the Company's revenue requirement, we shall deny the request of OTS to bar recognition of these changes in future rate cases. Nonetheless, OTS shall retain the right to oppose recognition in rates or to advocate any other

---

[5] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities,* Docket No. RM95-8-000; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Docket No. RM94-7-001, 70 F.E.R.C. ¶ 61,357 (1995), 60 *Fed. Reg.* 17662-17726 (April 7, 1995), IV F.E.R.C. Stats. & Regs., Proposed Regulations ¶ 32,514 at 33,057-33,069 (1995).

treatment for ratemaking purposes. Recently we adopted a policy on public utility depreciation practices.[6] That policy provides that:

> In subsequent ratemaking proceedings, the most recent annual depreciation report or service life study approved or deemed approved for accounting purposes only under this chapter, constitutes a rebuttable presumption as to the reasonableness of the accrued depreciation claimed for ratemaking purposes, and the burden of proving the unreasonableness of the accrued depreciation shall be on the challenging party.

52 Pa. Code § 73.9(c). Thus, the right of any party to challenge the proposed ratemaking treatment in a future rate case is preserved. Accordingly, we shall grant the request by OCA that we recognize this in our order so that it, OTS and other parties will maintain the opportunity to challenge the Company with respect to the impact of these changes on rates. **THEREFORE,**

IT IS ORDERED:

1. That the Petition of PECO Energy Company for a Declaratory Order Regarding the Acceleration of Depreciation and Amortization of Certain Regulatory Assets Associated With The Limerick Nuclear Station be, and hereby is, approved consistent with the foregoing Opinion.

---

[6] *Public Utility Depreciation Practices and Capital Planning*, Docket No. L-920062, Order (Entered June 22, 1995); 25 Pa.B. 3104 (August 5, 1995).

2. That this Order shall be without prejudice to the right of any customer of PECO Energy Company or representative thereof, the Office of Trial Staff, or any other party to a future rate case, to oppose or seek differing ratemaking treatment from that proposed by PECO Energy Company in recognition of these accounting changes.

3. That this docket shall be marked "Closed".

4. That a copy of this Order shall be served upon all persons having filed comments in this proceeding, and all parties of record in PECO Energy Company's most recent rate case at Docket No. R-891364.

BY THE COMMISSION,

John G. Alford

John G. Alford
Secretary

(SEAL)

ORDER ADOPTED: February 22, 1996

ORDER ENTERED: FEB 23 1996

Actual Generation Captial Spending vs 1989 Capital Forecast

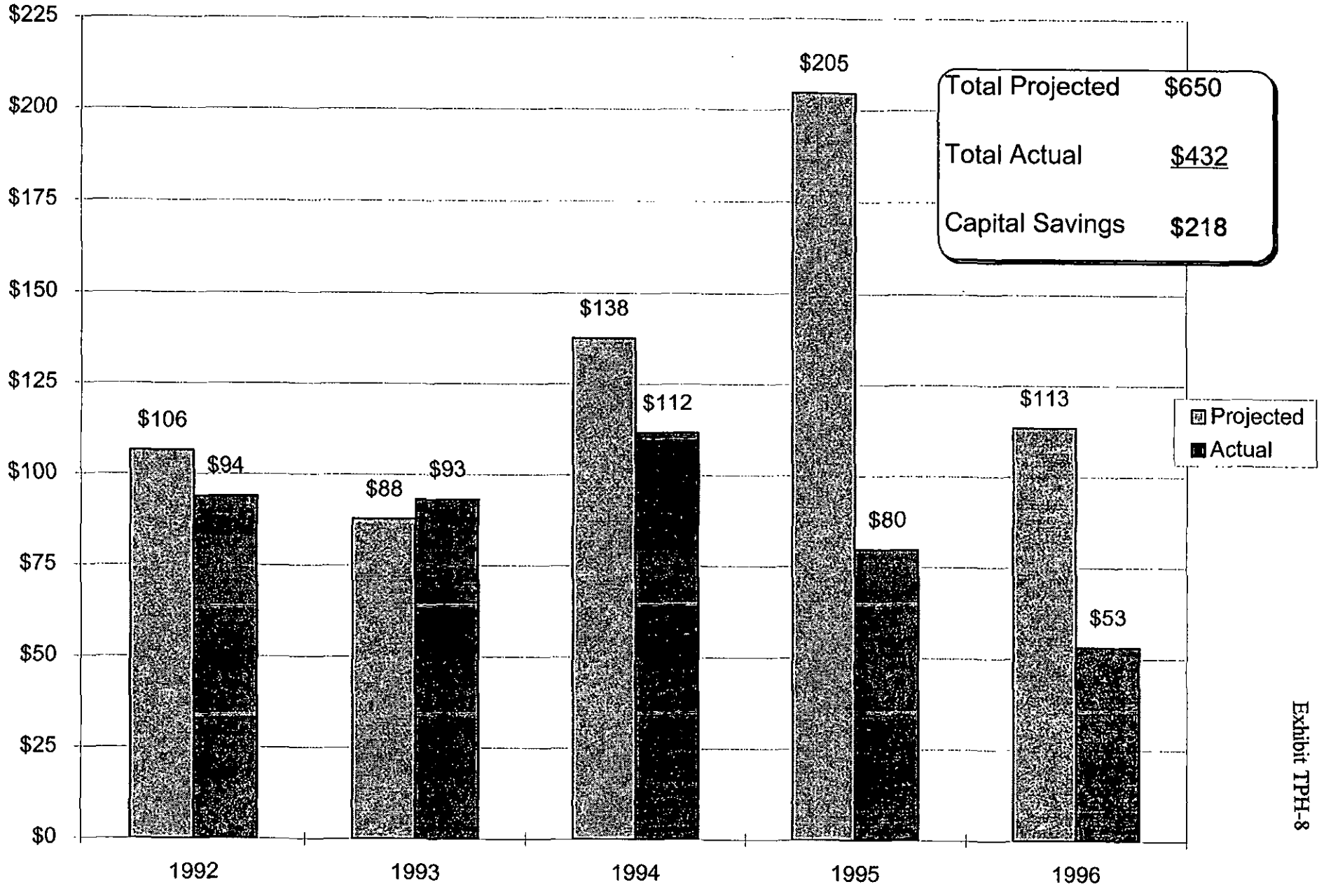


Exhibit TPH-8

PECO Energy Company
Non-Fuel O&M on Real vs Actual Basis

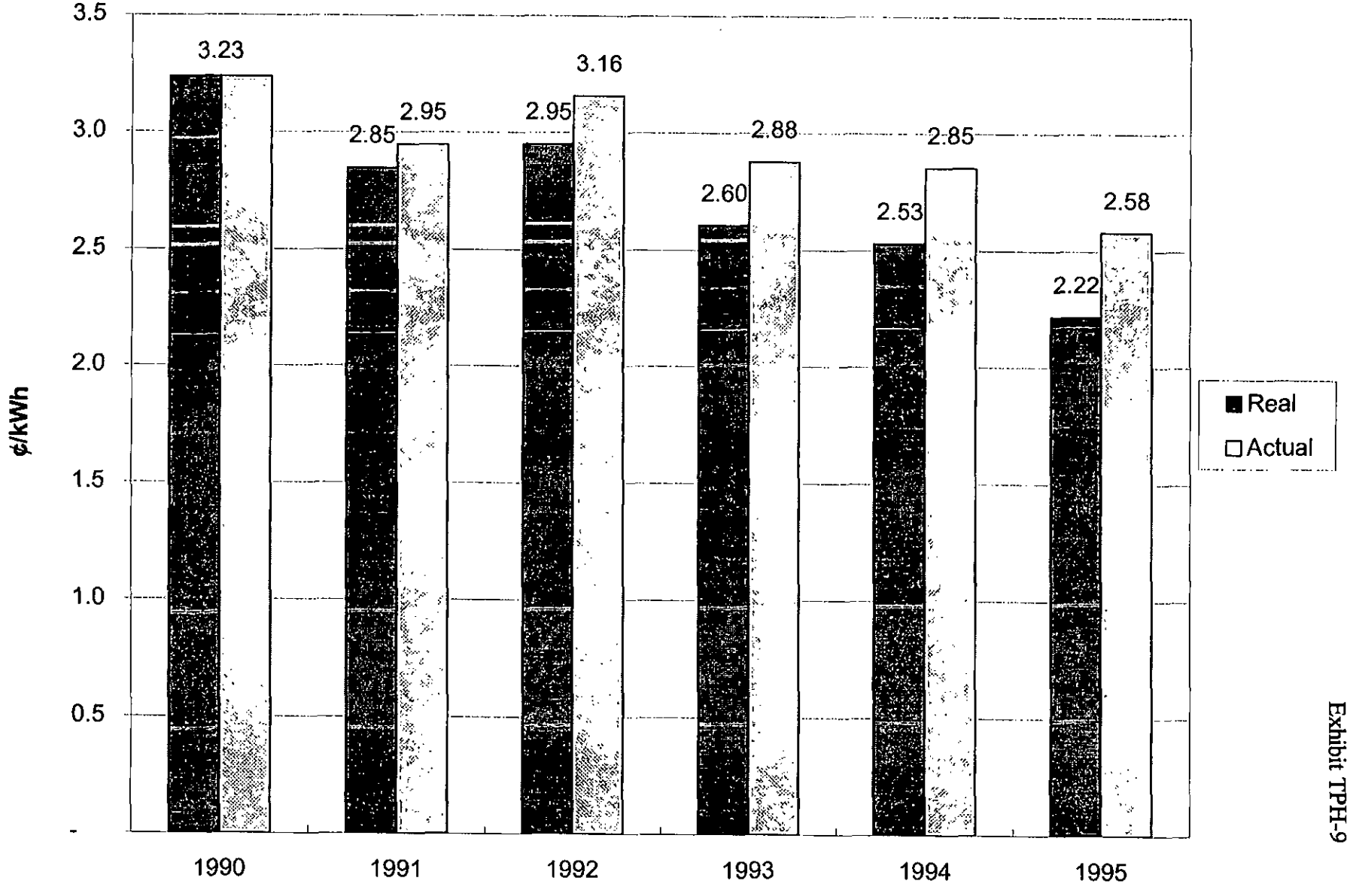


Exhibit TPH-9

The History of the Limerick Generating Station

Construction

Background

In response to the massive blackout in the Northeastern United States in the mid-1960's, the public utility commissions of Pennsylvania, New Jersey, Delaware, and Maryland held joint meetings in 1966 and 1967 to analyze the purpose and operation of the Pennsylvania-New Jersey-Maryland(PJM) interconnection. The commissions warned the electric utilities subject to their jurisdiction (and the public) that a desperate situation was developing which could result in additional blackouts or load curtailments in the near future. The companies were told to increase installed generating capacity so that a 20% reserve margin could be maintained.

The Decision to Add Nuclear Capacity

The initial decision to build the Limerick units was based upon an analysis performed in 1968 which showed that new capacity was required to meet customers' needs beginning in the 1975-1977 period. Once this need was identified, it was decided that the new capacity should be baseload generation. Baseload was selected because PECO Energy had sufficient levels of peaking and demand following capacity. A study was then performed which showed that a nuclear plant was the most economic choice when compared to the only other feasible options, coal and oil.

During the 1970's and 1980's, additional statutory and regulatory constraints came into existence that further limited utilities' decisions regarding generating plant construction. Due to the energy crisis, national policy after 1978 discouraged, and in some cases prohibited, the use of natural gas or oil in new generating plants. In addition, coal fired generating plants were discouraged in the eastern part of Pennsylvania due to air quality concerns.

Decisions to continue construction of the Limerick units were reviewed by PECO Energy on a continuing basis until construction on Limerick Unit 2 was well underway in the late -1980's. As described below, those decisions were evaluated on at least five separate occasions by the Pennsylvania Public Utility Commission (PaPUC).

The Construction

The Limerick project was officially announced in late 1969 and, at that time, had projected in-service dates of 1975 and 1977 for the two units. Pre-licensing

work was started in 1970 and the Company received a certificate of necessity from the PaPUC in 1971 which granted approval for the siting of the non-power plant related buildings at Limerick. The start of full scale construction, however, was delayed until 1974 due to new environmental regulations (National Environmental Policy Act of 1969) that had gone into effect. This delay in receiving a construction permit from the Atomic Energy Commission resulted in a revision to the projected in-service dates of the units to 1979 and 1980.

In late 1974, due to adverse financial factors brought on by the Arab Oil Embargo, the completion dates were delayed once again to 1981 and 1982. Subsequent to the Oil Embargo, PECO and other utilities experienced a substantial decline in the rate of growth of electric consumption. Through the 1960's and early 1970's load was growing at approximately 7% per year whereas after the embargo growth rates declined to less than 2% per year. This reduction in the level of load growth resulted in PECO's 1976 announcement to delay the in-service dates to 1983 and 1985. In 1978, continuing lower-than-anticipated load growth lead to another delay in the in-service dates to 1985 and 1987.

Limerick 1 first produced power in October 1984, although the licensing phase of construction was not completed and the plant was not officially in-service until February 1986.

Limerick 2 first produced power in 1989 and was placed in service in January 1990. The delay from the 1987 date referenced above was the result of a PaPUC investigation, which is discussed below.

Regulatory Reviews Of Whether It Was Prudent To Construct Limerick And Whether The Cost Of Construction Was Reasonable

1979 Rate Case (Docket No. R-79060865)

The first challenge to the completion of Limerick came in a base rate case (not related to Limerick) that was filed in 1979. The Office of the Consumer Advocate (OCA) had requested a special investigation to determine whether or not it was prudent to continue construction of Limerick. The Administrative Law Judge (ALJ) rejected the OCA position, stating that the Company should not be directed to terminate construction and that no special investigation was needed. The Commission concurred with the decision.

1980 Show Cause Investigation (Docket No. I-80100341)

In August 1980, the OCA filed a petition with the PaPUC requesting that the Commission order PECO Energy to show cause as to why the completion of Limerick was in the public interest. The start of the investigation to the end of the judicial appeals resulting from it spanned the period from August 1980 to February 1984. The investigation addressed such issues as the alternatives available at the time the decision to build the unit was made, currently available alternatives, the impact of construction delays, and the reasonableness of cost escalations.

This investigation, as with the investigations that followed, involved the testimony of dozens of expert witnesses presenting the views of not only PECO Energy, but also advocates for PECO Energy's customers, such as the OCA and industrial customers. The record of each of these investigations runs into the thousands of pages.

The ALJ, after reviewing the voluminous record in the 1980 investigation, determined that prompt completion of both units was in the public interest, stating that[1]

> " After reviewing the extensive record in this proceeding, I can come to but one conclusion--that at the present time there is no alternative available that can replace Limerick at a lower cost to the consumer, The record shows that a timely completion of Limerick Units I and II is in the best interest of PECO and its ratepayers....."

The Commission agreed with the ALJ with respect to the completion of Limerick 2 but concluded that the Company's financial condition was such that the simultaneous construction of both units was not feasible. As such the PaPUC ordered PECO Energy to either suspend or cancel construction of Limerick 2. Construction of Limerick 2 was suspended shortly thereafter and was not resumed, in full, until Limerick I was completed in February, 1986.

Limerick 2 Show Cause (Docket I-840381)

In August 1984 the PaPUC instituted another investigation of whether completion of Limerick 2 was in the public interest. The investigation addressed issues such as the need for Limerick 2's capacity, the alternatives available, the impact on PECO Energy's financial health, and the recovery of sunk costs. The ALJ in the case found that completion was not in the public interest. The PaPUC, however, reversed that decision and found that completion was in the public interest if a cost cap was established and certain operating incentives were established. The Company agreed to the Commission's terms for completion and resumed construction of Limerick 2 upon the completion of

[1] Limerick Nuclear Generating Station Investigation, PUC Docket No. I-80100341, Initial Decision of Administrative Law Judge Joseph J. Klovekorn, March 26, 1982.

Limerick 1 in February, 1986. The construction was completed for almost $400 million less than the agreed-to cap and nine months ahead of schedule.

A separate issue in the Limerick 2 Show Cause Investigation was whether PECO Energy needed a plant of this size. PECO Energy forecast at the time of the Limerick 2 investigation that its 1995 peak load would be 6500 MW. The ALJ in the case considered the Company's forecast to be too high; this was a primary reason for her conclusion that Limerick 2 should not be built. In fact, the actual 1995 peak load was 7246 MW.

Limerick 1 Rate Proceeding (Docket R-850152)

In September 1985 PECO Energy filed for a $682 million base rate increase. The primary purpose of the filing was to include Limerick 1 in ratebase. The Commission Order was issued in June 1986 and granted PECO Energy a $351 million increase. Issues concerning the need for the capacity from Limerick 1, and the impact of the construction delays, were addressed. The Commission found that the unit was needed and was not excess capacity. The Commission also ordered that PECO Energy's shareholders must pay for $369 million of the cost of Limerick Unit 1 to compensate for construction delays.

Limerick 2 Rate Proceeding (Docket R-891364)

In July 1989 the Company filed for a $548 million rate base increase. The primary purpose of the filing was to include Limerick 2 in rate base. The Commission Order was issued in April 1990 granting the Company a $242 million increase. The issues of physical and economic excess capacity as well as the impact of the construction delays were addressed in the proceedings. The Commission ultimately determined that 399 megawatts of excess capacity resulted from the addition of Limerick 2 and accordingly, reduced PECO's request rate increase by approximately $106 million. The Commission also ordered that PECO Energy's shareholders must pay for approximately $215 million of the construction cost of Limerick Unit 2.

Limerick Performance

Operating performance at the Limerick units has far exceeded all expectations that were used to evaluate whether it was an economic choice. Moreover, the cost of providing electricity from the Limerick units has declined substantially since operation began.

PECO Energy evaluates the economics of a new generating unit on a life cycle basis. The life cycle analysis provides a better comparison for projects that have

varying levels of capital expenditures. When evaluated on a life cycle basis, the Limerick generating units were always the economic choice. Rates, however, are set on embedded investment and, consequently, increased substantially when the Limerick units were first included in rate base. At the same time, high capital cost projects generally have low variable costs, thus resulting in lower rates in the future as the utility's investment is depreciated. This can readily be seen in the case of Limerick where the cost per kilowatt hour has declined from approximately 14 cents to about 7.5 cents.

In the Limerick investigations, the economics of the plant were evaluated on, in part, a projection that it would operate at a 65% capacity factor. The table below shows that the actual capacity factors achieved by Limerick have far exceeded that target:

Year	Limerick 1	Limerick 2
1986	81.0%	
1987	57.6%	
1988	72.0%	
1989	56.7%	
1990	60.8%	79.8%
1991	88.0%	77.3%
1992	67.2%	91.6%
1993	94.6%	80.7%
1994	85.0%	92.7%
1995	88.2%	86.7%
Avg.	75.1%	84.8%

By operating Limerick at these very high capacity factors, PECO Energy has been able to pass on to its customers savings that now cumulatively total in the hundreds of millions. These savings have been achieved by excellent operation of the nuclear units, including world record efficiency in recent refueling outages.

PECO STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF A QUALIFIED RATE ORDER UNDER
SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY OF

ALAN B. COHN

Regarding Quantification of Generation Assets,
Jurisdictional Allocation, Determination of Revenue Requirement
for Securitized Assets, Allocation of the Rate Changes

TABLE OF CONTENTS

DIRECT TESTIMONY OF ALAN B. COHN

I. QUALIFICATIONS

Q. **Please state your name and business address.**

A. Alan B. Cohn, 2301 Market Street, Philadelphia, PA 19103.

Q. **By whom are you employed and in what capacity?**

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Manager of the Business Analysis and Support Section in the Company's Rates and Regulatory Affairs Division.

Q. **Please describe your educational background.**

A. I received a Bachelor of Science Degree in Commerce and Engineering from Drexel University in 1980. In 1985, I received a Masters Degree in Business Administration from Drexel University. Additionally, I have completed the American Gas Association ("AGA") Gas Rate Fundamentals Course at the University of Wisconsin and the AGA Advanced Gas Rate course at the University of Maryland. Other formal training I have completed includes (1) the Kepner-Tregoe course in problem solving and decision making; (2) a management development course presented by Pennsylvania State University; and (3) courses in forecasting lives for depreciation and managing depreciation studies sponsored by Depreciation Programs, Inc.

Q. **Please describe your work experience with PECO.**

A. Upon graduation from Drexel in 1980, I was hired by PECO as a Rate Analyst in the Cost and Load Analysis Section of the Rate Division. My responsibilities in this position included the development of cost of service studies for PECO's

Electric and Gas Operations, as well as the development of the load study for Conowingo Power Company ("COPCO"), which was then a subsidiary of PECO.

In 1982, I transferred to the Rates and Regulations Section of PECO's Rate Division. My responsibilities in this section included analysis of rate structure and rate design; preparation of testimony and accounting exhibits in PECO's and COPCO's rate proceedings; review and analysis of testimony, administrative law judge opinions and commission orders; and participation in various financial and economic studies.

In 1987, I was appointed Supervisor of the Business Analysis Section in PECO's Rates and Regulatory Affairs Division, which is the successor of the former Rate Division. My responsibilities in this position included preparing supporting data for rate filings with the Pennsylvania Public Utility Commission (hereafter, the "Commission" or "PUC"), the Maryland Public Service Commission, and the Federal Energy Regulatory Commission ("FERC"); developing service lives for the utility property of PECO and COPCO; coordinating PECO's Engineering Economics Course; and preparing various economic studies.

In January 1995, I was named to my current position as Manager of the Business Analysis and Support Section in PECO's Rates and Regulatory Affairs Division. My responsibilities in this position include the overall management of the specific activities described above in connection with my prior positions with the Rate Division. In addition, I am responsible for the preparation of cost of service studies for use in proceedings before the PUC and the FERC and the development of electric load studies.

Q. **Have you testified previously in any regulatory proceedings?**

A. Yes. I testified before the PUC in the Limerick 2 rate case (Docket No. R-891364) with respect to PECO's revenue, expense, rate base and depreciation claims and submitted testimony in the Commission's Investigation Into Demand Side Management (Docket No. I-900005) regarding off-system sales issues and in the Company's rate filing at Docket No. R-00922479 concerning the appropriate ratemaking treatment of post-employment benefits other than pensions. I have also submitted testimony to the FERC in the rate proceedings for PECO and Susquehanna Electric Company (a PECO subsidiary) at Docket No. ER91-478, with respect to revenue, expense, rate base and tax claims. I have also testified before the Maryland Public Service Commission in support of COPCO's rate filings in Case Nos. 7982 and 8352 on the topics of revenues, expenses, taxes, and rate base.

II. INTRODUCTION AND SUMMARY

Q. **Please describe the scope and purpose of your testimony.**

A. My testimony will address five areas. First, I will identify and quantify the PECO assets and costs that are eligible for stranded cost recovery under the terms of the Electricity Generation Customer Choice And Competition Act (the "Competition Act"), which added Sections 2801 through 2812 to the Public Utility Code. These data were used by Mr. Hill to calculate PECO's costs that will be stranded as a consequence of electric industry restructuring mandated by the Competition Act. I have also identified the estimated useful lives and terminal dates for PECO's generating units. As more fully explained by Mr. Hill, these dates were used to calculate the generating units' market value, which is an input to the stranded cost calculation.

In the second part of my testimony, I will explain the derivation of the jurisdictional allocator that was used to determine the portion of PECO's stranded costs related to its Pennsylvania retail electric service.

In the third part of my testimony, I will explain how I calculated the amount to be deducted from PECO's base rates to reflect the portion of PECO's total stranded costs that it has requested the Commission to treat as Qualified Transition Expenses pursuant to a Qualified Rate Order to be issued in this expedited proceeding.

Fourth, I will explain how I calculated the amount PECO proposes to recover through an Intangible Transition Charge ("ITC") and how that amount was allocated among customer classes.

Finally, I will determine the net revenue requirement impact of securitizing both $3.6 billion in stranded costs and $277 million in issuance and refinancing costs.

In summary, my testimony will show that:

1) Total generation-related assets at December 31, 1998 are projected to be $9.7 billion.

2) All of these assets are needed to meet jurisdictional load over the transition period of 1999 to 2005.

3) The revenue requirement per $1 billion "slice" of all stranded costs is $203.1 million and is $203.5 million based upon the assets the Company is proposing to securitize in this filing.

4) The net reduction in revenue requirement from the securitization of $3.6 billion in stranded assets, and $277 million of issuance and refinancing January 20, 1997 expenses, is $95.4 million, or 2.9%.

III ASSETS AND COSTS THAT WILL BE STRANDED IN WHOLE OR IN PART

Q. Please explain the nature of the assets and costs that PECO claims will be stranded in whole or in part.

A. The Competition Act defines three types or classes of transition or stranded costs. They are:

1) Regulatory assets; the unfunded portion of projected nuclear decommissioning costs; and cost obligations under PUC approved contracts with non-utility generation projects ("NUGs");

2) Prudently incurred costs associated with the buyout or buydown of NUG contracts; and

3) Investment in generation plant, spent nuclear fuel disposal costs, long-term power purchase commitments, retirement costs associated with existing generating units, and other identifiable transition costs.

I have grouped these assets and costs into three major categories for purposes of discussion in my testimony. They are as follows:

- Generating plant assets
- Decommissioning expenses (Nuclear and Fossil)
- Regulatory assets

Q. Your cost categories exclude NUG costs. Does PECO have any NUG contracts?

A. Yes. PECO purchases energy from a number of NUGs that are "Qualifying Facilities" under Section 210 of the Public Utility Regulatory Policies Act. These purchases are made pursuant to PUC-approved contracts which, in some cases, obligate PECO to pay for capacity as well as energy. For PECO, however, the pricing of these contracts has generally been structured to track the market

prices of capacity and energy. Therefore, the Company is not making any claim in this filing for stranded costs associated with its NUG contracts.

Q. **As of what date are you identifying and quantifying the assets and costs used to calculate the Company's stranded costs?**

A. The valuation date used for purposes of quantifying stranded costs is December 31, 1998. Under the terms of the Competition Act, on January 1, 1999, the phase-in period for direct access to generation will begin, the Company's rates will be fully unbundled and a Competitive Transition Charge will be implemented.

Q. **Please summarize PECO's estimated generation-related costs at December 31, 1998.**

A. Exhibit ABC-1 is a summary of PECO's net generation-related costs. These data were used by Mr. Hill to calculate PECO's stranded costs.

A. GENERATING ASSETS

Q. **Please explain what is included in this category.**

A. This category includes the depreciated original cost of all of the Company's generating assets as of December 31, 1998. The starting point for determining original cost was the sum of the amounts recorded in Account Nos. 303-349 of the FERC's Uniform System of Accounts for Public Utilities and Licensees (Class A and B) as of December 31, 1996. To this I added estimates of the original cost of capital additions to Account Nos. 303-349 for the period January 1, 1997 to December 31, 1998.

From the original cost figure, I deducted the accrued depreciation related to Account Nos. 303-349 that was recorded on the Company's books as of

December 31, 1996. The depreciation that will be accrued from January 1, 1997 to December 31, 1998 was calculated by summing the annual depreciation for each calendar year within that period. A half-year convention was used for the first year that new plant additions would be in service. Annual depreciation was computed by applying remaining life accrual rates to the plant balances. The remaining life accrual rates for 1997 and 1998 were calculated by applying the average remaining lives and dispersions determined in the Company's most recent service life study. The Company's most recent service life study was completed in 1995 and is based upon retirement data through 1994. In its Order entered February 23, 1996, at Docket No. P-00950982, the Commission authorized PECO to begin recording depreciation, as of October 1, 1996, based upon the service lives determined in the 1995 study.

As shown on Exhibit ABC-1, PECO's net investment in generating facilities as of December 31, 1998, is anticipated to be approximately $6.5 billion.

Q. **Please identify the terminal dates for each of the Company's generating units.**

A. The terminal dates for each of the Company's generating units are show on Exhibit ABC-2. These dates reflect the life spans and interim survivor curves determined in the Company's 1995 service life study approved by the Commission in its February 23, 1996 Order.

B. ACCRUED UNFUNDED DECOMMISSIONING EXPENSES

1. Nuclear Decommissioning Expenses

Q. **What are nuclear decommissioning expenses?**

A. Nuclear decommissioning expenses are the costs to dismantle, decontaminate, remove and dispose of nuclear generating facilities at the end of their useful lives. Nuclear decommissioning, like all aspects of nuclear plant operation, is heavily regulated by the Nuclear Regulatory Commission ("NRC"). Nuclear decommissioning expenses are estimated on the basis of studies prepared by qualified experts with special knowledge of the planning, engineering and management of decommissioning projects and the applicable NRC requirements. Decommissioning cost studies are prepared periodically in order to obtain estimates that reflect the latest available data and regulatory mandates.

Q. **How are nuclear decommissioning expenses reflected for ratemaking and book purposes?**

A. For ratemaking purposes, the total estimated nuclear decommissioning expense for a nuclear generating unit is recovered over the estimated useful life of that unit. For book accounting purposes, the amount recorded as an annual expense for decommissioning is based upon the amount included in rates charged to customers. Under Generally Accepted Accounting Principles ("GAAP"), utilities are not required to record their total estimated decommissioning expenses as a liability, although the Financial Accounting Standards Board ("FASB") is currently reviewing whether it is appropriate to record such liability.

Q. **What is done with the amounts collected from customers for nuclear decommissioning expenses?**

A. As required by NRC regulations and applicable Commission orders, the amounts collected from customers are deposited in an external decommissioning trust fund, which can be used only for future decommissioning costs. Under the Internal Revenue Code, the amounts paid into a qualified decommissioning trust fund, as well as the earnings on the trust balance, are not treated as taxable income of the Company. Some amounts received by the Company to fund decommissioning expense do not qualify for tax deductibility. These amounts, net of taxes, are deposited in non-qualified trusts. Earnings upon non-qualified trust balances are taxed as income to the Company.

Q. **What is PECO's estimated nuclear decommissioning expense?**

A. Based on PECO's ownership shares in Limerick 1 and 2, Peach Bottom 1, 2 and 3 and Salem 1 and 2, PECO's total estimated decommissioning expenses, as of December 31, 1998, will be $1.52 billion (in year-end 1998 dollars).

Q. **How was the total nuclear decommissioning expense estimate of $1.52 billion determined?**

A. The nuclear decommissioning expense estimate was based on the results of site-specific studies for Limerick, Peach Bottom and Salem that were prepared by Mr. Thomas S. LaGuardia, President of TLG Services, Inc. Mr. LaGuardia estimated total decommissioning expenses, as of December 31, 1995, of $1.59 billion (in 1995 dollars). This estimate incorporates Mr. LaGuardia's use of an approximate 25% contingency factor. I made two adjustments to Mr. LaGuardia's estimate in establishing a value for stranded investment purposes. First, a downward adjustment of $175 million was made to reflect a contingency factor of 10%, which is consistent with the Commission's proposed Policy Statement on nuclear decommissioning approved on July 18. 1996. Second, in

order to obtain estimated decommissioning expenses as of December 31, 1998, I increased Mr. LaGuardia's estimates by the projected year-to-year changes in the Gross Domestic Product Implicit Price Deflator ("GDP deflator") for the three-year period from January 1, 1996 to December 31, 1998 to account for the effects of inflation.

Q. **How much of PECO's total estimated nuclear decommissioning expense will be funded as of December 31, 1998?**

A. As of October 31, 1996, approximately $251.7 million had been deposited in PECO's decommissioning trust fund. PECO is currently recovering in rates approximately $22 million per year of nuclear decommissioning expense, which is being deposited in the trusts on an on-going basis. Therefore, by December 31, 1998, an additional $44.8 million will have been deposited in the trust. Trust earnings during that same interval are estimated to be approximately $44.4 million based upon an assumed annual earnings rate of 7.5%. As a consequence, the trust balance at December 31, 1998 will be approximately $340.9 million.

Q. **How much of PECO's estimated nuclear decommissioning expense should be funded as of December 31, 1998?**

A. Based on the current estimate of decommissioning costs and the constant current accrual method approved in the Company's last base rate case, the trust balance plus any deferred tax balance should be $640.5 million to reflect the portion of the current estimate that should have been accrued during the period from the date of initial commercial operation of each nuclear generating unit to December 31, 1998, as shown on Exhibit ABC-3.

Q. **What portion of PECO's nuclear decommissioning expenses is included in its claim for stranded costs?**

A. As set forth in Exhibit ABC-3, PECO's stranded cost claim consists of the sum of the estimated fund deficiency amounts for each unit less deferred taxes associated with non-qualified funds, or approximately $281.8 million.

Q. **Following restructuring and unbundling of PECO's rates, how will the unfunded nuclear decommissioning expense that accrues commencing January 1, 1999 be recovered?**

A. Nuclear decommissioning expense that accrues on and after January 1, 1999, will be an element of the ongoing operating and maintenance expenses of the Company's nuclear generating units. That cost, like other components of operating and maintenance expense, is a deduction from the market price of generation. As such, these prospective decommissioning expense accruals must be reflected in the calculation of the market value of the Company's nuclear generating assets.

2. Fossil Decommissioning Expenses

Q. **What are fossil decommissioning expenses?**

A. Fossil decommissioning expenses are the cost to dismantle, remove and dispose of fossil-fired steam generating facilities at the end of their useful lives. Like the corresponding expenses for nuclear facilities, fossil decommissioning expenses are estimated on the basis of studies prepared by qualified experts with special knowledge and expertise in the areas of planning, engineering and managing such projects.

Q. **How are fossil decommissioning expenses reflected for ratemaking and book purposes?**

A. Fossil decommissioning expenses are treated as a cost of removal. Under existing Pennsylvania regulatory practice, neither the cost of removal nor any salvage value is recognized until an asset is retired and the cost of removal is actually incurred. The actual cost of removal less any associated salvage value (net negative salvage) is recorded as a deduction from accrued depreciation and, thereby, is amortized over the remaining life of applicable plant accounts through the operation of the remaining life method. Stated another way, both the expense recognition and rate recovery for fossil decommissioning expenses are after-the-fact. Because of the ratemaking and accounting procedures explained above, there has been no recognition of the decommissioning costs that will be *incurred upon retirement of PECO's fossil-fired generating units. Thus, unlike* nuclear decommissioning expenses, PECO's fossil decommissioning expenses have not been funded.

Q. **How does Pennsylvania's regulatory treatment of fossil decommissioning expenses differ from that of other jurisdictions?**

A. In many other jurisdictions, a utility is entitled to reflect prospective net negative salvage, which includes decommissioning expenses, in calculating its annual depreciation expense accrual. Typically, this is done by adding an estimate of future net negative salvage to the plant costs to which the annual accrual rate is applied to calculate the annual depreciation expense accrual. Under that method, estimated decommissioning expenses are recovered on a prospective basis over the lives of the generating units to which they relate. This procedure has not been employed in Pennsylvania since the Superior Court's 1962 decision in Penn Sheraton Hotel Co. v. Pa. P.U.C., which has generally been read as barring the prospective recovery of decommissioning costs by Pennsylvania utilities. However, an exception to that principle was recognized

for nuclear decommissioning expenses due to the significant health and safety concerns associated with the closure of nuclear facilities and the NRC's requirements for pre-funding of nuclear decommissioning expense.

Q. **What is the estimated fossil decommissioning expense for which PECO is *financially responsible*?**

A. For fossil-fired steam generating units totally or jointly owned by PECO, the Company estimates decommissioning expenses of $336.4 million.

Q. **How was the total fossil decommissioning expense estimate of $336.4 million determined?**

A. Fossil decommissioning expense was estimated for the units listed in Exhibit ABC-4 based upon the methodology used by Mr. LaGuardia in PP&L's 1994/1995 base rate case. To obtain estimated decommissioning expenses as of December 31, 1998, I increased the cost per kW determined by Mr. LaGuardia, in PP&L's recent rate case, by the year-to-year changes in the GDP deflator from 1994 to December 31, 1998 to account for the effects of inflation. These data provide an indication of the magnitude of PECO's fossil decommissioning expense. The Company intends to continue to review these expenses and may provide revised estimates as part of its restructuring plan to be filed on or after April 1, 1997.

Q. **What portion of PECO's fossil decommissioning expenses is included as a stranded cost?**

A. As set forth in Exhibit ABC-4, PECO's stranded assets include fossil decommissioning expenses equal to $275.1 million, consisting of the portion of those expenses that would have been recovered if total estimated decommissioning expenses had been accrued ratably since the in-service date

of each fossil-fired generating unit based upon its current estimated useful life and attained age as of December 31, 1998.

Q. **Following restructuring and unbundling of PECO's rates, how will the fossil decommissioning expenses that would accrue on and after January 1, 1999 be recovered?**

A. Fossil decommissioning expense that would accrue on and after January 1, 1999, will be an element of the ongoing operating and maintenance expenses of the Company's fossil generating units. That cost, like other components of operating and maintenance expense, is a deduction from the market price of generation. As such, these prospective decommissioning expense accruals must also be reflected in the calculation of the market value of the Company's fossil generating assets. Additionally, I would note that when the Statement of Financial Accounting Standard No. 71 ("SFAS 71") Accounting For The Effects Of Certain Types of Regulation ceases to apply to PECO's generation function, PECO will have to accrue this expense each year.

C. REGULATORY ASSETS

Q. **What is a regulatory asset?**

A. A regulatory asset is defined in SFAS 71 Accounting for the Effects of Certain Types of Regulation, as follows:

> Regulators sometimes include costs in allowable costs in a period other than the period in which the costs would be charged to expense by an unregulated enterprise. That procedure can create assets (future cash inflows that will result from the rate-setting process) . . . For general-purpose financial reporting, an incurred cost for which a regulator permits recovery in a future period is accounted for like an incurred cost that is

reimbursable under a cost-reimbursement-type contract.

Q. **Please identify the regulatory assets recorded on PECO's books of account that are eligible for stranded cost recovery under the terms of the Electric Competition Act.**

A. PECO has recorded on its balance sheet and/or will be entitled to recover as of December 31, 1998, generation-related regulatory assets, excluding nuclear and fossil decommissioning underfunding, totaling $2.633 billion. In general, regulatory assets are recorded in FERC Account No. 186 (Miscellaneous Deferred Debits) or FERC Account No. 182 (Unrecovered Plant and Regulatory Costs) with some exceptions such as deferred fuel and unamortized loss on reacquired debt. I will describe below each regulatory asset that the Company is entitled to reflect in rates under current regulatory practice. A summary of the Company's regulatory assets is provided in Exhibit ABC-1, page 3.

Carrying Charges And Deferred Depreciation On 50% Of Limerick Common Plant. Limerick is a two unit generating station that utilizes common facilities, such as a common fuel floor and spent fuel pool, to support the operation of both units. Functionally, over 80% of the common facilities are needed to support the operation of Limerick 1. However, in the rate proceeding in which Limerick 1 was first claimed in PECO's rate base, the Commission applied its policy of including in rate base only 50% of common plant. In its Order entered June 27, 1986, at Docket No. R-850152, the Commission directed PECO to accrue but defer carrying charges on the 50% of Limerick common plant not included in rate base in that case and to defer the associated depreciation expense on that property. The carrying charges were to be based upon the Company's accrual rate for Allowance For Funds Used During Construction ("AFUDC"). The Commission stated that the deferred carrying charges and depreciation could be

claimed for recovery in a subsequent rate proceeding.

In its Order entered May 16, 1990, at Docket No. R-891364, the Commission addressed, among other issues, the Company's claim to include Limerick 2 and the remaining 50% of Limerick common plant in rate base. Subject to certain adjustments discussed in that Order, the Commission treated the deferred carrying charges and depreciation like a capitalized plant cost by directing PECO to amortize the deferred costs "above-the-line" over the life of Limerick 2 and allowing PECO to earn a return on the unamortized balance.

On October 27, 1995, PECO filed a Petition For A Declaratory Order in which it requested Commission approval to accelerate the depreciation of Limerick 1 and 2 and to accelerate the amortization of certain regulatory assets associated with those units. With specific reference to the deferred carrying charges and depreciation on 50% of Limerick common plant, PECO requested permission to amortize the unrecovered balance over a nine-year period commencing October 1, 1996. By Order entered February 23, 1996, the Commission granted the approvals sought by PECO. Reflecting continued amortization of the deferred carrying charges and depreciation at the rate approved in the Commission's February 23, 1996 Order, the unamortized balance at December 31, 1998 will be $175.8 million.

Carrying Charges And Deferred Depreciation On 50% Of Eddystone, Peach Bottom And Salem Common Plant. These costs are similar to the carrying charges and deferred depreciation for Limerick, which were previously described, and arise from the application of the Commission policy allowing only 50% of common plant in a utility's rate base for ratemaking purposes when the first unit of a multi-unit plant is placed in service. These costs are not recorded in FERC Account No. 186 because they were incurred prior to FERC's directive

on accounting for the Commission's regulatory policy. However, in every PECO rate case since each of these costs was incurred, the Commission has permitted a return of and a return on these amounts. The unrecovered cost of this asset at December 31, 1998 is projected to be $17.4 million.

Unamortized Loss On Reacquired Debt. To encourage prudent refinancing, the Commission has consistently permitted utilities a return on and a return of tender and call premiums paid to reacquire high coupon rate debt. The return of premium costs is accomplished by amortizing such costs over the stated life of the new issue. The return on premium costs is accomplished by deducting the unamortized balance of the premiums from the net outstanding debt when calculating capitalization ratios and debt cost rates. This has the effect of increasing the cost rate of the new issue by an increment that provides a return, at the new issue's average coupon rate, on the unamortized premium balance. Under GAAP, unregulated entities record tender and call premiums as a charge against income in the year in which they are incurred. However, as a consequence of the ratemaking treatment afforded by the Commission, as described above, tender and call premiums incurred by PECO were recorded on its balance sheet as a regulatory asset. The Company began amortizing these costs from the date of recordation. The portion of that amount related to the Company's generating assets as of December 31, 1998 will be $179.7 million. The allocation to the generation function was based on net plant because debt financing is driven by plant construction. The development of the allocator and the allocated portion of the asset is set forth in Exhibit ABC-5.

Nuclear Design Basis Documentation. The project was initiated in 1988 in connection with industry-wide initiatives to consolidate and validate design-basis information so that it would be readily available to assist plant operations, engineering, and design and inspection activities. The goal was to have a single

source map for all design-basis information in order to streamline engineering and operating/inspection activities in cases where familiarity with the underlying basis of system design is required. Industry guidelines were established by NUMARC (Nuclear Utilities Management Resources Council) in the 1990 time frame and supported by the NRC. The NRC was concerned that licensees should be able to verify the consistency between the design basis and the actual plant configuration.

PECO formally requested FERC's opinion on the proper method of recording these costs. By its Order dated November 23, 1992, at Docket No. AC-92-170-000, the FERC determined that these costs were more akin to plant costs than expenses. Accordingly, the FERC directed that the costs should be recorded as a deferred item in FERC Account No. 182.2 (Unrecovered Plant Costs And Regulatory Studies) and should be amortized "above-the-line" over the remaining lives of the Company's nuclear units to which they relate. This is appropriate because the benefits of this project will be realized over the lives of the plants. Since the date of the FERC's Order, the Company has been amortizing these costs. As of December 31, 1998, the unamortized balance will be $29.0 million.

Peach Bottom And Limerick Water Chemistry System Changes. This project was started at Peach Bottom in 1986, as a potential solution to intergranular stress corrosion cracking (IGSCC), which was a problem that surfaced in the large bore piping at Peach Bottom and other nuclear plants in the 1980's. The project was stopped in 1987, and was restarted in 1989. The system was tested in 1991, but did not operate as planned and was not completed. A letter was sent to the FERC requesting permission to record the costs in FERC Account No. 182 (Unrecovered Plant And Regulatory Costs) and to amortize these costs over the remaining life of the plant. FERC granted the

Company's request. Recently, however, work has restarted on this project, and some of the costs may be transferred to construction-work-in-progress ("CWIP").

A similar project was initiated at Limerick to eliminate any potential for IGSCC at that plant. The project was stopped in 1991 after the testing at Peach Bottom proved unsatisfactory. This work was also recently restarted, and part of the project may be transferred to CWIP or plant in service during 1997. The unamortized balance of these costs at December 31, 1998 is projected to be $6.7 million. Of that amount, approximately $5.0 million is related to Peach Bottom and $1.7 million is related to Limerick.

Limerick "Early Window" Declaratory Order Deferred Costs. The date of commercial operation of a new nuclear generating unit can, and usually does, differ from the effective date of rates that reflect the unit's inclusion in rate base. If commercial operation commences in advance of the effective date of new base rates, the utility will begin to recognize substantial costs because applicable regulatory accounting procedures mandate that, once utility property is placed in service, the associated carrying costs, depreciation and operating and maintenance expenses can no longer be capitalized. At the same time, the commercial operation of a nuclear unit will typically result in substantial energy cost savings that will be passed through to the utility's customers under its Energy Cost Rate ("ECR") or in PECO's case, its Energy Cost Adjustment ("ECA").

To deal with this problem, PECO filed a Petition For A Declaratory Order on June 15, 1984, in which it requested the Commission to afford "early window" treatment to the costs the Company would recognize if Limerick 1, which was then nearing completion, went into commercial operation in advance of the Commission's approval of new rates reflecting it in rate base. Specifically,

PECO asked that the Commission authorize deferral of the carrying costs, depreciation and operating and maintenance expenses of Limerick 1 from the date of its commercial operation to the rate effective date, as well as the deferral of the fuel savings that Limerick 1 would produce during the same period. By its Order entered September 28, 1984, at Docket No. P-840514, the Commission authorized the deferrals PECO requested and stated that PECO could make a claim for recovery of the deferred costs, net of fuel saving, in "an appropriate proceeding filed subsequent to the entry of a Final Order in the Limerick Unit 1 rate case proceeding."

Subsequently, when Limerick 2 was nearing completion, PECO filed a Petition For A Declaratory Order requesting Commission approval of "early window" treatment in the event that unit entered commercial operation in advance of the effective date of new rates reflecting its inclusion in the Company's rate base. By its Order entered May 3, 1989 at Docket No. P-890349, the Commission authorized a deferral on a basis similar to that provided for in its Limerick 1 Early Window Order.

On July 21, 1989, PECO filed a rate increase that was driven principally by its request to include Limerick 2 in its rate base for ratemaking purposes. In that case, PECO claimed recovery of $137 million of costs, net of fuel savings, that had been deferred pursuant to the Limerick 1 Early Window Order. In its Order entered May 16, 1990 at Docket No. R-891364, the Commission authorized PECO to amortize those deferred costs over a 10-year period.

As previously discussed, In October 1995, PECO sought PUC approval to accelerate the depreciation of Limerick 1 and 2 and to accelerate the amortization of certain related regulatory assets. In particular, PECO requested approval to begin to amortize the Limerick 2 deferred costs over a nine-year

period beginning October 1, 1996. In its Order entered February 23, 1996, the PUC granted PECO's request and recognized that the revenue source to provide for such amortization would be "subsumed within existing rates" as augmented by revenues "made available through the operation of the Company's Competitive Breakthrough Strategy."

Reflecting continued amortization through December 31, 1998, the unamortized balances of the Limerick 1 and 2 Early Window costs as of that date will be $18.3 million and $68 million respectively.

Deferred Fuel Costs. On December 5, 1996, PECO filed with the Commission a Petition for a Tentative Order to allow it to roll its energy costs into base rates and to eliminate both its ECA and its Limerick Settlement Adjustment ("LSA").[1] In addition, PECO requested that the Tentative Order establish its right to recover certain additional costs not reflected in its current energy costs, through a Competitive Transition Charge ("CTC"), an ITC or an automatic adjustment clause established under Section 1307 of the Public Utility Code. The additional costs PECO sought approval to recover total $306.3 million, plus interest thereon at 9%. The total of $306.3 million consists of three components:

- PECO's under-recovery of energy costs as of December 31, 1996, which was projected to be $80 million. (The actual 1996 underrecovery was subsequently determined to be $69.7 million.)

---

[1] The LSA is an automatic adjustment provision that was initiated to implement the settlement of PECO and OCA appeals from the PUC's Order in the Limerick 2 rate case. Under the terms of the settlement, PECO is entitled to retain a portion of the energy cost savings made possible by Limerick 2 as well as a portion of off-system power sales.

- $22 million to which PECO is entitled under the 1996 Nuclear Performance Factor of its ECA (the actual number was determined to be $22.3 million); and
- $204.3 million reflecting the 0.7 mills per kWh by which the Company's average energy costs rolled into base rates from its ECA understate its projected energy costs for the 9-year period from January 1, 1997 to December 31, 2005, i.e., approximately $22.7 million per year (due to rounding in the roll-in of the ECA, this number was adjusted to $22 million).

In its Tentative Order entered December 19, 1996, the Commission approved PECO's request to roll its energy costs into base rates and to eliminate both the ECA and LSA. As part of that Order, the Commission revised PECO's projection of understated future energy costs to $198 million, i.e., approximately $22 million per year. However, as to PECO's request that the Commission approve its recovery of additional costs totaling $306.3 million, the Commission stated as follows:

> While the Commission denies the Company's request to grant recovery of these amounts with finality at this time, the Commission nevertheless recognizes the Company's right to defer these costs and to file for recovery of these undercollections in the future. Under normal regulatory practice, these undercollections would be reconciled in filings to be made in April of 1997 and would be recovered from customers over the next automatic adjustment clause period, provided that the costs incurred were prudently incurred and reasonable in amount . . . .
>
> * * *
>
> Accordingly, the Company's under recovered energy and other costs that have been deferred to date may continue to be accumulated and deferred post-December 31, 1996. In the Commission's opinion, these accumulated deferrals are

> "regulatory assets and other deferred charges typically recoverable under current regulatory practice" within the meaning and scope of Section 2808(c)(1). As such, these are costs that are recoverable in the future as part of an electric utility's Competitive Transition Charge, Intangible Transition Charge, or an automatic adjustment clause, so long as the total charges do not exceed the electric utility's rate cap.

Based upon the Commission's Tentative Order, the Company has an opportunity to establish a regulatory asset, at December 31, 1998, of $311.6 million, consisting of the deferred amount of $290.0 million ($198 million plus the 1996 balance of $92.0 million) plus interest of $21.6 million. The interest was calculated at 9%. That interest rate was applied to the components of the $290.0 million principal amount as follows:

- As to PECO's $69.7 million under recovery of energy costs for the 12 months ended December 31, 1996 and the $22.3 million of shared energy savings to which PECO is entitled under the Nuclear Performance Factor of its ECA, interest was calculated on the entire $92 million balance for the period from December 31, 1996 to December 31, 1998.

- As to additional energy costs of $22 million per year for the period from January 1, 1997 to December 31, 2005, interest was calculated on a principal balance of $11 million for the period from January 1, 1997 to December 31, 1997 and on a principal balance of $33 million for the period from January 1, 1998 to December 31, 1998.

Deferred SFAS 106 Costs. Statement of Financial Accounting Standards No. 106 ("SFAS 106"), which became effective as of January 1, 1993, established a GAAP requirement that employers utilize an accrual method of accounting to recognize expenses associated with the provision of benefits other than

pensions to retired employees ("other post-employment benefits" or "OPEBs"). The cost of health care insurance benefits are the principal component of OPEBs. Until the effective date of SFAS 106, employers were permitted to account for OPEBs on a "cash" basis, such that health insurance costs for retired workers were recorded as an expense when they were paid. The adoption of SFAS 106 created an immediate increase in the level of OPEB expenses recognized for financial reporting purposes.

In order to provide a revenue stream to offset the expense recognition required by SFAS 106, PECO filed a rate increase request with the Commission on September 11, 1992. Following evidentiary hearings, the Commission entered an Order on September 2, 1993, in which it found that PECO's operating expenses would increase by $36.5 million per year to recognize SFAS 106 costs, but PECO was barred by the terms of an earlier settlement from increasing its rates to reflect those costs. However, the Commission authorized PECO to defer that amount each year for recovery in a future rate case.

PECO appealed the Commission's Order to the Commonwealth Court of Pennsylvania. During the pendency of the appeal, a settlement was reached among the parties. The settlement provided that PECO would be permitted to increase its electric base rates by $25 million to fully fund its SFAS 106 obligation. Additionally, the settlement provided that the SFAS 106 costs deferred by PECO for the years 1993 and 1994 pursuant to the Commission's Order would be amortized over an 18-year period, and such amortization "will be deemed subsumed in the rates prescribed [by the settlement]." The settlement was approved by the Commission in its Order entered October 19, 1994 at Docket No. R-00922479. As a consequence of the foregoing, PECO has a regulatory asset for the unamortized portion of the deferred SFAS 106 costs.

A second aspect of PECO's regulatory asset for deferred SFAS 106 costs relates to a portion of the so-called "transition obligation" created by the adoption of SFAS 106. In addition to mandating the accrual of current period OPEB expenses, SFAS 106 required employers to record an additional expense, which arose as a result of the one-time transition from cash to accrual accounting. In short, the transition obligation reflects OPEB accruals related to employees' service up to the date of adoption of SFAS 106. SFAS 106 permits employers to recognize the transition obligation over a prospective period of up to twenty years (i.e., a twenty-year amortization). PECO chose to use the full twenty-year period to recognize its transition obligation under SFAS 106. A revenue stream to fund this expense has been provided as part of the $25 million base rate increase implemented pursuant to the settlement explained above.

In 1994, PECO initiated Voluntary Retirement And Separation Incentive Programs, and offers of retirement or separation were accepted by a number of the Company's employees. Under applicable GAAP for voluntary retirement and separation programs, PECO was required to recognize as an expense, in the year of retirement or separation, the portion of its entire transition obligation that related to the employees who accepted early retirement or separation. As a result, OPEB expenses that otherwise would have been recognized over a prospective 18-year period were, instead, recognized in 1994 for book purposes. However, as explained above, recovery of the expenses recognized in 1994 is provided for in PECO's existing rates, which will produce a revenue stream, over the amortization period, equal to those expenses. Therefore, the voluntary retirement and separation-related OPEB expenses are a regulatory asset, and have been recorded in that fashion on the Company's balance sheet.

The unamortized balance of this asset that relates to the generation function will be $114.2 million as of December 31, 1998. The allocation of the asset to the generation function was based upon the proportion of generation-related labor expense to total labor expense. Exhibit ABC-5 provides the development of the generation allocation factor.

Compensated Absences. Unused sick leave and vacation time is compensable upon an employee's retirement or separation. PECO accrues a liability for the amounts that will be paid to employees that retire or otherwise leave its employment with unused sick leave or vacation time. These expenses are recoverable for ratemaking purposes on the basis of actual expenditures. Accordingly, there is a timing difference between recognition of the expense for book purposes and its recovery for ratemaking purposes. Therefore, the book accrual is a regulatory asset. The amount of this asset that relates to the generation function will be $18.8 million at December 31, 1998. The allocation to the generation function was based upon the proportion of generation-related labor expense to total labor expense. Refer to Exhibit ABC-5 for the allocation of this asset.

Deferred SFAS 109 Tax Expense. The application of Statement of Financial Accounting Standards No. 109 ("SFAS 109"), Accounting For Income Taxes, requires PECO to record as a deferred liability; 1)the tax-reductive effects of certain tax/book-timing differences the tax benefit of which the Company was required by the PUC to flow-through to customers in the ratemaking process; and 2) the deferred taxes netted against AFUDC. These differences "reverse" over time and, as a result, will increase the Company's revenue requirement in the future. Under normal ratemaking procedures, the Company is entitled to recover the future-period increases in tax expense in the rates charged to

customers. Accordingly, under SFAS 71, a regulatory asset was recorded in an amount equal to the deferred tax liability.

The Company's regulatory asset consists of three principal components of tax expense for which a flow-through method was used for ratemaking purposes. One element is the effect of deductions for accelerated depreciation for purposes of (a) the Pennsylvania corporate net income tax ("CNI Tax") for all vintages of property and (b) certain federal income taxes for pre-1981, i.e., pre-ACRS, vintages of property. The use of accelerated depreciation and the flow-through method in calculating these taxes for ratemaking purposes produced a significantly greater deduction, and correspondingly less tax expense, than if the straight-line, book-life method or full normalization accounting had been employed. That reduction in tax expense, which was flowed-through to customers, will reverse at a later point in the life of each asset, when accelerated depreciation produces deductions that are less than the straight-line method and tax expense is correspondingly higher. Simply stated, it is as if the Company had loaned customers the tax benefits produced by accelerated depreciation in the early years of an asset's life, subject to an agreement that the customers would pay back the loan at a later date when the tax benefits "reverse" and must be paid over, by the Company, to the Commonwealth of Pennsylvania and the federal government. In light of this regulatory treatment, a regulatory asset was properly recorded representing the amounts that would have to be collected from customers to pay future taxes. When the Commission adopted the flow-through method it recognized that customers would have to pay higher taxes in the later years of asset lives.

The second component relates to pensions, benefits and taxes that are capitalized as part of the original cost of utility plant for book accounting purposes but deducted for tax purposes. For ratemaking purposes, PECO

flowed-through the CNI tax and federal income tax effects of these current period deductions. For book purposes, pensions, benefits and taxes were capitalized. Thus, a tax-book timing difference was created for which a deferred tax liability must be recognized under SFAS 109. However, under normal regulatory practice, the depreciation expense related to this element of original cost would not give rise to an income tax deduction in calculating income taxes for ratemaking purposes but, instead, would be treated as income, and PECO would be entitled to recover its tax liability on that addition to taxable income over the life of the asset. In light of this regulatory treatment, a regulatory asset was properly recorded representing the amounts that would have to be collected from customers to pay these future taxes.

The third component of this regulatory asset relates to AFUDC. The Company's AFUDC rate is used to capitalize, for book purposes, the cost of funds expended on CWIP. The amounts capitalized as AFUDC become part of plant costs and the Company obtains a return on and a return of these amounts through rates when the plant is placed in service and is included in rate base for ratemaking purposes. Like PECO's weighted average cost of capital, its AFUDC rate contains both a debt and equity cost component. AFUDC accrued prior to 1991 was recorded on the basis of an AFUDC rate that reflected PECO's debt and equity cost rates on an after-tax basis. That is, the debt return capitalized during construction was reduced to reflect the deductibility of interest when incurred and the capitalized equity return did not include a "gross-up" to reflect the income taxes that would be payable when that equity return is collected, in the future, over the life of the plant to which it relates. The application of SFAS 109 required the Company to create a deferred tax liability equal to the sum of (a) the income tax deduction reflected in the net-of-tax recordation of the debt component of AFUDC; and (b) the unrecorded income tax on the equity component of AFUDC. However, for ratemaking purposes, the Company is

entitled to recover these income taxes in the rates established by the Commission because the book depreciation expense on the AFUDC-related component of the original cost would not be deductible in calculating income taxes for ratemaking purposes, therefore, historically the PUC has allowed utilities to gross-up such expenses to recover the applicable income taxes. Consequently, over the life of the asset to which the AFUDC relates, the Company will receive revenues to offset the deferred tax liability. Accordingly, a regulatory asset equal to the deferred tax liability was recorded. The Commission has in the Company's past rate cases included in rates the higher taxes associated with the AFUDC and the capitalized pensions and benefits portion of depreciation expense.

In 1993, the Company was required to adopt SFAS No. 109 for financial accounting purposes. Many non-regulated companies recorded a charge against earnings when establishing the deferred tax liability required by SFAS No. 109. However, because of the ratemaking policy of the Commission that allows recovery from customers of the future tax liability recognized under SFAS No. 109, PECO and other similarly regulated utilities were permitted to record a regulatory asset concurrent with recording the liability.

The Company's total regulatory asset for SFAS 109 related to its generating plant will be $1,693.2 million as of December 31, 1998.

D. AUDITS

Q. **Have the Company's plant costs, regulatory asset recordations and energy clause costs and revenues been audited by regulatory agencies and PECO's independent auditors?**

A. Yes, both the PUC and the FERC conduct audits of the Company's continuing property records, regulatory assets and the operation of its PUC and FERC energy clauses. The last PUC audit of the Company's continuing property records was in 1993. The last completed fuel audit was for the year 1994. The FERC last audited the Company's books in 1995. The Company's independent auditors, Coopers & Lybrand, perform annual audits of the Company's financial statements. Additionally, on January 14, 1997, the Commission's Bureau of Audits commenced an audit of the Company's continuing property records and regulatory assets.

IV. JURISDICTIONAL ALLOCATION

Q. **What is the jurisdictional allocation?**

A. The jurisdictional allocation provides a basis for segregating costs between those assets and costs that are used to provide Pennsylvania retail electric service and those that relate to FERC jurisdictional sales. Only the stranded costs that relate to Pennsylvania retail electric service are being claimed for recovery by PECO.

Q. **How was the jurisdictional allocation determined?**

A. I first determined the portion of PECO's total generating capacity that is needed to meet its Pennsylvania retail electric load and to provide a reasonable reserve margin. The Company's generating capacity above the level thus determined is treated as non-jurisdictional. The ratio of Pennsylvania jurisdictional capacity to

total capacity is the factor that will be used to determine the portion of PECO's total stranded costs it will seek to recover from its retail customers.

Q. **How did you determine the portion of PECO's total generating capacity that is needed for Pennsylvania jurisdictional load?**

A. I used the same method employed by the Commission in its final Order in the Company's Limerick 2 base rate case. In that proceeding, the Commission determined that a reasonable level of installed capacity would be 22% above the peak load projected for the summer following the end of the future test year in that case. The 22% figure was derived from the reserve margin used by the Pennsylvania-New Jersey-Maryland Interconnection ("PJM") for planning purposes for its planning years that included PECO's test year and the year following.

Because there is no "test year" in this proceeding, I evaluated reserve margin, based upon an 18% requirement, over the transition period. It is appropriate to analyze needed generating capacity over that time frame because, under the terms of the Competition Act, the Company retains the obligation to serve as generation supplier until the end of the transition period and is under a mandatory rate cap. For purposes of determining required capacity, I compared the average peak demand for that period to the Company's installed capacity at December 31, 1998 as adjusted in the manner explained below.

Q. **What assumptions did you use in your analysis?**

A. The starting point for my analysis was the Company's 1996 Annual Resource Planning Report. I adjusted the peak load data for known changes, such as interruptible customers that have migrated to firm service or reduced their interruptible load and the elimination of the projected effect of the Company's proposed Demand Side Management project. I also adjusted the installed

capacity data to remove any units determined to be uneconomic and as such do not operate in the market value analyses sponsored by Mr. Hill. Finally, I used 18% as the appropriate reserve margin because that is the level used in the determination of the market value of the Company's generating units, as explained by Mr. Bustard.

Q. **What is the result of your analysis?**

A. The analysis provided in Exhibit ABC-6 shows that all of PECO's installed capacity plus an additional 46 Mw would be required to meet jurisdictional customer demands in the transition period.

V. SECURITIZATION CALCULATIONS FOR PECO'S STRANDED COSTS

A. REVENUE REQUIREMENT REDUCTION

Q. **How did you calculate the revenue requirement reflected in the Company's rates that is associated with the assets and costs included in PECO's stranded cost claim?**

A. My calculations are provided in Exhibit ABC-7. Page 1 of that exhibit is a summary of the revenue requirement associated with PECO's stranded costs. As previously explained, revenue requirement was calculated at June 30, 1997. As of that date, PECO's total generation-related investment (excluding underfunded decommissioning) will be $9.325 billion and the associated revenue requirement included in the Company's rates will be $1.894 billion.

The balance of Exhibit ABC-7 shows the supporting calculations for the revenue requirement data summarized on page 1. These calculations were done separately by asset or asset category because the revenue requirement is

different for different components of stranded costs. The calculation for each component is explained below.

GENERATING ASSETS

The revenue requirement associated with the Company's generating assets is summarized on page 2 of Exhibit ABC-7. The total revenue requirement of $1,413.3 million, which includes Gross Receipts Tax, consists of $1,010.1 million of pre-tax return and $403.2 million of annual depreciation expense. The return was calculated on the basis of net plant of $6.715 billion and a pre-tax rate of return of 15.60%.

The capitalization ratios and the debt cost rate used to calculate the 15.60% pre-tax rate of return reflect Commission-approved adjustments to provide a return on and a return of PECO's losses on reacquired debt in the manner I previously described in Section III.C. The effect of those adjustments must be removed from the rate of return calculation because I make a separate calculation to remove the revenue requirement associated with this regulatory asset . If they were not removed, there would be a double counting of the revenue requirement deduction. Accordingly, as shown on the bottom half of page 4 of Exhibit ABC-7, I calculated the rate of return using capitalization ratios and a debt cost rate without adjustments to provide a return on and return of losses on reacquired debt.

To determine the pre-tax rate of return, the weighted cost rates of preferred and common stock were "grossed-up" based on the current CNI and federal income tax rates and the overall rate of return was grossed-up based on the current Pennsylvania Gross Receipts Tax rate.

The annual depreciation accrual shown on page 2 of Exhibit ABC-7 is based on the estimated depreciation accrual for the plant in service at June 30, 1997.

Q. **Mr. Cohn, in developing the revenue requirement reduction related to net plant, as shown on page 2 of Exhibit ABC-7, you applied an "Adjustment for Future Tax Payouts." Please explain why this adjustment is being made.**

A. As of December 31, 1996, the Company has recorded on its books Accumulated Deferred Taxes ("ADT") related to generating plant totaling $1.010 billion, which reflects a tax liability that the Company will have to pay-out over the remaining tax-depreciable life of that property. However, if the Company securitizes a portion of its net plant, the transaction would appear, for book accounting purposes, similar to a sale of the asset. If the asset actually were sold for its book depreciated original cost, a tax-recognition event would occur, a taxable gain would be recognized and a tax liability equal to the ADT balance would be paid out in a lump sum. That payment would reduce the net proceeds of the "sale" and, in that event, it would be appropriate to adjust the revenue requirement reduction by the entire amount of the tax liability.

However, because the securitization is not a sale for tax purposes, the tax payment will not be made in a lump sum. Nonetheless, the same tax liability will be paid out eventually. While these payments will also reduce the benefits of the securitization realized by the Company, the effect on the Company today is less than a lump sum payout, because, as I previously explained, the tax payments will be made over the life of the Transition Bonds. Accordingly, the economic effect on the Company must be levelized to reflect the time value of the funds for the period the Company will hold them prior to pay-out. To do that, I calculated a levelized adjustment factor in the manner shown on pages 1 and 2

of Exhibit ABC-8, which I applied in the manner shown on page 2 of Exhibit ABC-7.

ACCRUED BUT UNFUNDED DECOMMISSIONING EXPENSES.

Accrued but unfunded decommissioning expenses, both fossil and nuclear, are not reflected in the Company's existing rates and, therefore, no rate reduction should be made in conjunction with the recovery of this stranded cost.

REGULATORY ASSETS

The development of the revenue requirement associated with PECO's regulatory assets is shown on page 3 of Exhibit ABC-7. For purposes of explaining the revenue requirement development, regulatory assets can be divided into four categories, as explained below.

Regulatory Assets Not Currently Reflected In Rates. This category includes the Company's deferred fuel costs, which are not being recovered, to any extent, in PECO's rates, as explained in Section III.C.

Regulatory Assets For Which PECO's Rates Are Providing Only A Return Of Its Investment. As shown on page 3 of Exhibit ABC-7, there are four assets in this category: the Limerick 1 and 2 "Early Window" deferred costs; deferred SFAS 106 costs; compensated absences; and the Peach Bottom and Limerick water chemistry system costs.

The revenue requirement associated with the Limerick 1 "Early Window" deferred costs was calculated based on the 10-year amortization of these costs approved by the Commission in its Order at Docket No. R-891364. The revenue requirement associated with the Limerick 2 "Early Window" deferred

costs reflects the 9-year amortization of these costs over the period that commenced October 1, 1996, as approved by the Commission in its Order at Docket No. P-00950982.

The revenue requirement associated with deferred SFAS 106 costs reflects the amortization of those costs over an 18-year period that commenced January 1, 1995, pursuant to the settlement approved by the Commission in its Order entered October 19, 1994 at Docket No. R-00922479.

Compensated absences historically have been reflected in rates on a "cash" or "pay-as-you-go" basis. Typically, these costs are paid out when an employee retires or otherwise separates from the Company. Current levels of cash payouts are not representative of the level included in rates because recent retirement and separation packages have decreased current expenses below a normal, on-going level. Therefore, I have assumed 5% of the total asset to be a reasonable estimate of future costs. The 5% figure reflects a 20-year amortization, which is the same amortization period used for SFAS 106 transition costs.

The Peach Bottom and Limerick water chemistry system costs are being treated like an abandoned plant cost, pursuant to the accounting treatment approved by the FERC. Accordingly, the Company is assuming that its existing rates are providing recovery of, but not a return on, its investment in this engineering work. The associated revenue requirement was calculated based on an amortization over the remaining lives of the plants.

Regulatory Assets For Which PECO's Rates Are Providing A Return Of And A Return Of Its Investment.

As shown on page 3 of Exhibit ABC-7, there are four items in this category: the carrying charges and deferred depreciation on 50% of Limerick common plant; similar amounts with respect to Eddystone, Peach Bottom and Salem; unamortized loss on reacquired debt; and the nuclear design basis documentation.

As explained in Section III.C., the carrying charges and deferred depreciation on 50% of Limerick common plant are treated similarly to plant investment. Accordingly, the associated revenue requirement consists of pre-tax return and amortization. The return component was calculated using the same pre-tax rate of return employed for the Company's generating assets, as explained previously. The return of the Company's unrecovered investment was calculated on the basis of a 9-year amortization commencing October 1, 1996, as approved by the Commission in its Order entered February 23, 1996 at Docket No. P-00950982. Similar treatment was afforded the comparable unamortized balances for Eddystone, Peach Bottom and Salem costs in accordance with the amortizaton periods previously approved by the PUC for these costs.

The nuclear design basis documentation costs are being treated similarly to a plant cost, pursuant to the accounting treatment approved by the FERC. Accordingly, the Company is assuming that its existing rates are providing a return of, and a return on, its investment in this work. The associated revenue requirement was calculated using the same pre-tax rate of return employed for the Company's generating assets and an amortization of the unrecovered investment over the remaining lives of the Company's nuclear plants.

The revenue requirement associated with the unamortized loss on required debt was calculated in a manner consistent with the way the Company would recover a return of and a return on these costs for ratemaking purposes. The return component was calculated based upon the Company's embedded cost of debt. The revenue requirement associated with the recovery of the unamortized costs was based on an amortization period equal to the stated life of the required debt.

Deferred SFAS 109 Tax Expense. As explained in Section III.C., deferred SFAS 109 costs represent tax liabilities that PECO will pay to the state and federal governments over the remaining lives of the property that generated these book-tax timing differences. If these costs are securitized, then PECO's customers will, in effect, be pre-funding these liabilities and, therefore, they should receive the benefit of a rate base reduction for the period that PECO holds these funds prior to pay-out. In a regulated environment, this would be accomplished by reflecting an appropriate rate base reduction each time the Company's base rates were changed. Assuming periodic base rate filings, changes in the rate base reduction could be made to mirror the continuing pay-out of taxes to the government over time. However, under the terms of the Competition Act, there will be a one-time calculation of stranded costs and, therefore, the opportunity to adjust the rate base reduction in the future, which continued rate regulation would provide, no longer exists. To address this problem in a manner that is fair to PECO and its customers, the appropriate revenue requirement reduction in conjunction with the securitization of deferred SFAS 109 costs should be based upon a levelized amount of the pre-funded SFAS 109 deferred costs prior to pay-out over the term of the Transition Bonds. I have assumed a 10-year term for purposes of this calculation consistent with the expected life of the transition bonds. This calculation is shown on page 2 of Exhibit ABC-8. As shown on the accompanying exhibit, I estimated levelized

accumulated deferred tax balances based upon the balances of the end of each year during the 10-year period. Because deferred SFAS 109 costs are an asset that represents the amount required to pay future taxes, the levelized estimate is based upon the anticipated actual pattern of payment of the tax liabilities represented by the deferral. By developing the revenue requirement associated with a levelized rate base deduction, customers are given an appropriate credit for the period of time that the cash received by the Company to fund its SFAS 109 regulatory asset is available to it prior to pay-out. The amortization of SFAS 109 costs is developed on page 5 of Exhibit ABC-7.

Q. **Have you summarized the estimated revenue requirement reduction related to PECO's total stranded costs?**

A. Yes. I have summarized the toal revenue requirement reduction of $1,236.3 million in Exhibit ABC-9.

Q. **How are the rate reductions associated with Net Securitization Adjustment calculated?**

A. There are two separate revenue requirement impacts that must be calculated. First, the reduction associated with removing the securitized assets from existing rate levels must be determined. The second step is to determine the appropriate Intangible Transition Charge (ITC) that must be imposed based upon the Transition Bonds to be issued to securitize the assets. I will discuss these calculations in detail below.

Q. **Have you determined the revenue requirement reduction associated with securitizing the Company's stranded assets?**

A. Yes, Mr. Hill requested that I determine the revenue requirement reduction associated with securitizing the full level of stranded investment. On Exhibit ABC-9, I have calculated the effect on rates of the Company's securitizing $7.1

billion in assets (total stranded), in the manner discussed by Mr. Mitchell. Based upon this analysis, the net proceeds of $7.1 billion would be used first to fund $556 million of decommissioning costs and $240 million of deferred fuel expense. The remaining $6.3 billion would be used to securitize the Company's stranded assets, as defined in Exhibit ABC-7. The revenue requirement reduction associated with the use of the proceeds is $1236.3 million, as shown in Exhibit ABC-9.

B. CALCULATION OF THE ITC

Q. **Have you determined the revenue requirement increase associated with the ITC?**

A. Yes. The calculation of the ITC is a function of the amount that will be securitized and the interest rate and principal amortization period of the Transition Bonds. The amount to be securitized includes, in addition to stranded costs, the issuance expenses (including the costs to serve the Transition Bonds) and call and tender premiums that PECO will incur in connection with the refinancing of portions of its existing capital structure. At this point, the interest rate and principal amortization period for the Transition Bonds is not known. However, as shown on Exhibit ABC-9, for illustrative purposes, I have calculated the levelized annual payment amounts (i.e. similar to a mortgage) associated with a securitized amount of $7.1 billion (the Company's full stranded investment) assuming an effective interest rate of 7.42% and a term of 10 years. The securitization of $7.1 billion of assets would require the issuance of Transition Bonds with a principal of $7.7 billion. The difference of $0.6 billion would be used for issuance expenses associated with the Transition Bonds (including costs to be incurred serving the Transition Bonds) and call premiums on bonds and stock. Effectively, these additional costs are financed at the low

at the low cost of the Transition Bonds. Assuming a 7.42% effective interest rate and a 10 year term, the annual ITC is $1115.4 million.

Note that the Company will be responsible for gross receipts tax ("GRT") associated with the ITC revenue since ITC revenue is considered a sale of electricity for GRT purposes. As such, the revenue requirement reduction calculated above will be reduced by the gross receipts tax on the ITC revenue. While the actual amounts may change, the methodology described above and used in Exhibit ABC-9 will be used when the final costs are available to establish the actual net rate reduction.

C. NET REDUCTION TO CUSTOMERS

Q. **What would be the net impact on customers of securitizing all of the Company's stranded costs?**

A. The net impact of the revenue requirement reduction from removing assets from rate base and the increase in revenue requirement from the ITC would be savings to customers of $120.9 million per year. This equates to approximately a 3.7% average rate reduction.

VI. SECURITIZATION CALCULATION FOR PECO'S CLAIM

Q. **Have you quantified any scenarios other than the securitization of PECO's full stranded costs?**

A. Yes. As noted by Mr. Hill, PECO is requesting to securitize only $3.6 billion in stranded assets. I have, in Exhibit ABC-10, developed both the revenue requirement reduction and the ITC increase associated with securitizing $3.6

billion in stranded assets. Mr. Hill also notes that for purposes of determining the assets to be securitized, the amounts included for nuclear design basis documentation, Peach Bottom/ Limerick water chemistry, compensated absences, and decommissioning (both fossil and nuclear) are to be excluded. As shown in Exhibit ABC-10, the revenue requirement associated with a slice of the remaining stranded assets in this scenario is $203.5 million. The results of this analysis, which are presented in Exhibit ABC-10, page 1, shows that customers would receive a $658.1 million base rate reduction. Concurrently, the ITC would increase revenue requirement by $562.7 million. The net impact is a reduction of $95.4 million per year or 2.9%.

VII. ALLOCATION OF REVENUE REQUIREMENT CHANGES

Q. ***Please explain how the revenue requirement reductions and ITC are to be allocated among rate classes.***

The allocation of this revenue requirement reduction is shown in Exhibit ABC-10, page 2. In accordance with Sections 2808(a) and 2812 (g) of the Competition Act, both the revenue requirement decreases and the ITC costs will be allocated on the basis of the allocation factors used for similar costs in the Company's cost of service study employed in its last base rate case. Because virtually all of the Company's stranded costs are capacity-related generation costs, the associated revenue requirement reductions will be allocated among rate classes using the allocation factor for capacity costs, which is based on the four coincident peak ("CP") methodology. However, in the case of the ITC, a small portion of the assets securitized are energy-related (ie. the deferred fuel). In order to properly allocate these costs, I have used a weighted schedule of the peak and energy allocators from the Company's last rate case (Docket No. R-891364). This methodology, while theoretically correct, results in slight increases to some classes of service that have not been allocated any rate reduction. Increasing

rates would violate the cost cap imposed by the Competition Act; therefore, I have reallocated this amount to the classes receiving rate decreases. The effect on these classes is minimal, and the results are then within the cost cap.

Q. **Please provide an example of the allocation of the rate reduction and the ITC.**

A. An illustration of the rate-class allocation is provided in Exhibit ABC-11 based on securitizing all of PECO's estimated stranded assets and the associated transition costs. The four coincident peak method (4CP) allocation factors used for these allocations are shown for each rate class. These allocators were taken from the cost of service study submitted in the Company's last base rate case.

Q. **Why do certain classes receive no rate reduction yet incur an ITC payment?**

A. Off-peak customers, such as those on Rate OP and the street lighting rates (SLS, SLE, POL), do not consume electricity at the time of the system peak and therefore were not allocated any fixed generation costs in establishing their rates. Since the assets being securitized were allocated based upon the 4CP methodology, the rate reduction should be similarly allocated and will result in no reduction for rates that did not contribute to the peak. Allocation based upon another methodology could cause interclass subsidization.

In the case of the ITC, however, a portion of the costs being securitized are energy related (ie. deferred fuel) and appropriately allocated on an energy schedule. As their costs are not currently included in rates, there was no rate reduction associated with securitizing these costs. The net result is that the aforementioned rates receive a small increase since they use energy but receive

no decrease because they don't contribute to the average of the four system coincident peaks which was used to allocate the reduction.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

PECO Energy Company
Generation Assets
as of December 31, 1998
(thousand $)

Net Generating Plant & CWIP	$	6,514,017	Exhibit ABC - 1,p.2
Regulatory Assets	$	2,632,577	Exhibit ABC - 1,p.3 incl. deferred fuel
NUG Contracts	$	-	
Nuclear Decommissioning	$	281,790	Exhibit ABC - 3
Fossil Decommissioning	$	275,116	Exhibit ABC - 4
Total	$	9,703,500	

PECO Energy Company
Development of Generation Net Plant
As of 6/30/97 and 12/31/98
(Thousand $)

	1996(act.)	1997	1998
Net Plant @ 1/1		$ 6,769,329	$ 6,660,467
Plus: Capital Additions		$ 276,613	$ 155,600
Less: Depreciation on base		$ 377,757	$ 393,193
Depreciation on Cap adds		$ 7,718	$ 4,593
Net Plant @12/31	$ 6,769,329	$ 6,660,467	$ 6,418,281
Estimated CWIP	$ 382,610	$ 178,583	$ 95,736
Total Net Plant & CWIP	$ 7,151,939	$ 6,839,050	$ 6,514,017

	Est 6/30/97
Net Plant @ 1/1	$ 6,769,329
Plus: Capital Additions	$ 138,307
Less: Depreciation on base	$ 188,879
Depreciation on Cap adds	$ 3,859
Net Plant @6/30	$ 6,714,898

PECO Energy Company
Estimated Balance of Regulatory Assets
as of December 31, 1998
(thousand $)

Description	Bal@12/31/96	Annual Amort		Est Bal @ 12/31/98
CC on 50% Limerick Common	$ 227,904	$ 26,046		$ 175,812
Unamortized Loss on Reacq Debt	$ 215,849	$ 18,072		$ 179,705
Nuclear Design Basis Document	$ 31,899	$ 1,463		$ 28,973
PB/Lim Water chemistry system	$ 7,507	$ 414		$ 6,679
Limerick 1 Declaratory Order	$ 45,729	$ 13,714		$ 18,301
Limerick 2 Declaratory Order	$ 88,129	$ 10,072		$ 67,985
SFAS No. 106	$ 130,513	$ 8,156		$ 114,201
SFAS No. 109	$ 1,919,352	$ 113,066	(a)	$ 1,693,220
Compensated Absences	$ 20,925	$ 1,046		$ 18,833
CC on 50% Comm PB/Sal/Eddy	$ 19,272	$ 936		$ 17,400
Sub-Total Regulatory Assets	$ 2,707,079	$ 192,985		$ 2,321,109
Electric Fuel Deferral 1996	$ 92,021	$ -		$ 109,330
Additional Fuel Deferral	$ 198,000	$ -		$ 202,138
Nuclear Decomm Underfunding	-	$ -		$ 281,790
Total Regulatory Assets	$ 2,997,100			$ 2,914,367
Other Transition Costs				
Fossil Plant Decommissioning				$ 275,116

(a) refer to Exhibit ABC-7,p.5 for the development of the amortization

PECO ENERGY COMPANY
GENERATING UNITS
RETIREMENT DATES FOR DEPRECIATION PURPOSES

Station Name & Unit No.		(1) Unit Type	Summer Rating MW	Installation Date	Estimated Retirement Year	Age
Chester	7	GT	13	1969	(5)	
	8	GT	13	1969	(5)	
	9	GT	13	1969	(5)	
Conemaugh	1	ST	176(2)	1970	2005	35
	2	ST	176(2)	1971	2006	35
	D	IC	2.3(2)	1970	2006	36
Conowingo	1	HY	36	1928	2014	86(3)
	2	HY	36	1928	2014	86(3)
	3	HY	36	1928	2014	86(3)
	4	HY	36	1928	2014	86(3)
	5	HY	36	1928	2014	86(3)
	6	HY	36	1928	2014	86(3)
	7	HY	36	1928	2014	86(3)
	8	HY	65	1964	2014	50(3)
	9	HY	65	1964	2014	50(3)
	10	HY	65	1964	2014	50(3)
	11	HY	65	1964	2014	50(3)
Cromby	1	ST	144	1954	2004	50
	2	ST	201	1955	(5)	
	D	IC	2.7	1967	(5)	
Croydon	11	GT	47	1974	1999	25
	12	GT	48	1974	1999	25
	21	GT	45	1974	1999	25
	22	GT	47	1974	1999	25
	31	GT	47	1974	1999	25
	32	GT	45	1974	1999	25
	41	GT	45	1974	1999	25
	42	GT	45	1974	1999	25
Delaware	7	ST	126	1953	(5)	
	8	ST	124	1953	(5)	
	9	GT	15	1970	(5)	
	10	GT	13	1969	(5)	
	11	GT	13	1969	(5)	
	12	GT	13	1969	(5)	
	D	IC	2.7	1967	(5)	
Eddystone	1	ST	279	1960	2010	50
	2	ST	302	1960	2010	50
	3	ST	380	1974	2009	35
	4	ST	380	1976	2011	35
	10	GT	13	1967	(5)	
	20	GT	13	1967	(5)	
	30	GT	15	1970	1995	25
	40	GT	15	1970	1995	25
Falls	1	GT	15	1970	1995	25
	2	GT	15	1970	1995	25
	3	GT	15	1970	1995	25

Station Name & Unit No.		(1) Unit Type	Summer Rating MW	Installation Date	Estimated Retirement Year	Age
Keystone	1	ST	178(2)	1967	2002	35
	2	ST	179(2)	1968	2003	35
	D	IC	2.3(2)	1968	2003	35
Limerick	1	NB	1055	1985	2024	40(4)
	2	NB	1115	1990	2029	40(4)
Moser	1	GT	15	1970	1995	25
	2	GT	15	1970	1995	25
	3	GT	15	1970	1995	25
Muddy Run	1	PS	110	1967	2014	47(3)
	2	PS	110	1967	2014	47(3)
	3	PS	110	1967	2014	47(3)
	4	PS	110	1967	2014	47(3)
	5	PS	110	1967	2014	47(3)
	6	PS	110	1967	2014	47(3)
	7	PS	110	1968	2014	46(3)
	8	PS	110	1968	2014	46(3)
Peach Bottom	2	NB	464(2)	1974	2014	40(4)
	3	NB	464(2)	1974	2014	40(4)
Richmond	91	GT	48	1973	1998	25
	92	GT	48	1973	1998	25
	D	IC	2.7	1967	1990	23
Salem	1	NP	471(2)	1977	2016	39(4)
	2	NP	471(2)	1981	2020	39(4)
	3	GT	18(2)	1971	1996	25
Schuylkill	1	ST	166	1958	(5)	
	10	GT	13	1969	(5)	
	11	GT	15	1971	(5)	
	D	IC	2.8	1967	(5)	
Southwark	3	GT	13	1967	(5)	
	4	GT	13	1967	(5)	
	5	GT	13	1967	(5)	
	6	GT	13	1968	(5)	

Foot Notes:

1. Unit Types
   GT = Combustion Turbines — NB = Nuclear BWR
   ST = Fossil Steam — NP = Nuclear PWR
   IC = Diesel — PS = Pumped Storage Hydro
   HY = Hydro
2. PECO share of jointly owned units
3. Expiration of FERC license
4. Expiration of NRC license
5. *These units are operating beyond their original estimated retirement.* Periodic comprehensive engineering reviews are undertaken to assess their continued operation.

PECO ENERGY COMPANY
ESTIMATED NUCLEAR DECOMMISSIONING FUND DEFICIENCY
AS OF DECEMBER 31, 1998

Key Assumptions

Earnings Rate = 7.5%
Inflation Rate = GDP Deflator
Contingency Rate Used = 10%
Costs are based upon a study performed by TLG & Associates in 1995/96

	Est Decom Cost @ 12/31/98	Fund Ratio	Fund Required @ 12/31/98	Est Fund Balance @ 12/31/98	Est Fund Deficiency
Peach Bottom 1	$53,568	0.60	$33,480	$8,305	($25,175)
Peach Bottom 2	$187,159	0.60	$116,974	$56,022	($60,952)
Peach Bottom 3	$187,159	0.60	$116,974	$56,087	($60,887)
Salem 1	$142,397	0.55	$81,878	$42,674	($39,204)
Salem 2	$142,397	0.44	$65,722	$36,981	($28,741)
Limerick 1	$355,651	0.34	$121,670	$88,903	($32,767)
Limerick 2	$449,798	0.23	$103,780	$51,941	($51,839)
Total	$1,518,129		$640,478	$340,913	($299,565)
Less: Deferred Taxes as of 12/31/98					$17,775
Net Deficiency =					($281,790)

	Est Serv Life	Years in Rates	Fund Ratio
Peach Bottom 1	40	24	0.60
Peach Bottom 2	40	24	0.60
Peach Bottom 3	40	24	0.60
Salem 1	40	22	0.55
Salem 2	39	17	0.44
Limerick 1	38.5	13	0.34
Limerick 2	39	9	0.23

PECO Energy Company
Fossil Decommissioning Cost Estimates

Exhibit ABC - 4

	1999	GDP Implicit Price Deflator					1999 Cost					
1994 costs $/kw		1995	1996	1997	1998	1999	in $/kw					
Total Less Scrap (a)	115.4	1.0204	1.02	1.0196	1.0288	1.00935	127.2					
kw based on summer rating						Years from					Decom Cost	Decom Cost
Fossil Plant	Date Installed	Terminal Date		Net Cap. MW Summer	Type of Fuel	Inst Date to Collect Date	Inst Date to Terminal Date	Portion Accrued Ratio	Decom Cost ($1,000)		Portion Accrued ($1,000)	From Market ($1,000)
CONEMAUGH 1	1970	2005		176	COAL	29	35	0.828571	$ 22,387		$ 18,549	$ 3,838
CONEMAUGH 2	1971	2006		176	COAL	28	35	0.8	$ 22,387		$ 17,910	$ 4,477
CROMBY 1	1954	2004		144	COAL	45	50	0.9	$ 18,317		$ 16,485	$ 1,832
CROMBY 2	1955	1999		201	OIL	44	44	1	$ 25,567		$ 25,567	$ -
DELAWARE 7	1953	1999		126	OIL	46	46	1	$ 16,027		$ 16,027	$ -
DELAWARE 8	1953	1999		124	OIL	46	46	1	$ 15,773		$ 15,773	$ -
EDDY 1	1960	2010		279	COAL	39	50	0.78	$ 35,489		$ 27,681	$ 7,808
EDDY 2	1960	2010		302	COAL	39	50	0.78	$ 38,414		$ 29,963	$ 8,451
EDDY 3	1974	2009		380	OIL	25	35	0.714286	$ 48,336		$ 34,526	$ 13,810
EDDY 4	1976	2011		380	OIL	23	35	0.657143	$ 48,336		$ 31,764	$ 16,572
KEYSTONE 1	1967	2002		179	COAL	32	35	0.914286	$ 22,769		$ 20,817	$ 1,952
KEYSTONE 2	1968	2003		178	COAL	31	35	0.885714	$ 22,642		$ 20,054	$ 2,588
(a) based upon an analysis of the data filed in Pennsylvania Power & Light rate case (docket R-943721)									$336,444		$ 275,116	$ 61,328

PECO Energy Company
Development of Regulatory Asset Allocation

Plant Allocator(data from 12/31/95 Qtrly Earnings Report filed with PaPUC)

Generation Plant	$	6,974,586	76.04%
Transmission Plant	$	444,694	4.85%
Distribution Plant	$	1,689,771	18.42%
Other	$	62,893	0.69%
Total	$	9,171,944	100%

Labor Allocator (p.354 1995 FERC Form 1)

Generation payroll	$	177,465
Total Payroll	$	316,687
Generation/Total		56.04%

Allocated Regulatory Assets	Total@ 12/31/96		Allocated	Allocator
Unamortized loss on reacquired debt	$	283,853	$ 215,849	plant
SFAS No. 106	$	232,901	$ 130,513	labor
Compensated Absences	$	37,341	$ 20,925	labor

Exhibit ABC-6

PECO Energy Company
Development of Jurisdictional Capacity
(MW)

Year	Installed Capacity		Peak Demand	Interruptible	DSM	Net Peak	Req @18% Reserve
1997	9164		7074	204	0	6868	8104
1998	9214	(a)	7183	204	0	6973	8228
1999	9214		7277	148	0	7129	8412
2000	8597	(a)	7354	148	0	7206	8503
2001	8597		7458	148	0	7310	8626
2002	8597		7536	148	0	7388	8718
2003	8597		7615	148	0	7467	8811
2004	8597		7694	148	0	7546	8904
2005	8453	(a)	7775	148	0	7627	9000
Average (1999 - 2005)	8665		7530	148	0	7382	8711

Jurisdictional = Avg Required / Avg Installed = 100.00%

Note: Data is taken from PECO Energy Company's 1996 Annual resource Planning Report

(a) The following are the capacity changes
In 1998 - add 50Mw for a Limerick rotor
- deduct 56Mw from interruptible load based upon known changes
In 2000 - deduct 166Mw for Schuylkill(based upon economics)
In 2000 - deduct 201 Mw for Cromby 2(based upon economics)
In 2000 - deduct 250 Mw for Delaware (based upon economics)
In 2005 - deduct 144 Mw for Cromby 1 (based upon economics)

PECO Energy Company
Revenue requirement included in Rates
For Stranded Investment
Estimate as of June 30 , 1997
(Thousand $)

	Balance	Total Revenue Reqmt	Rev Reqmt $1 billion Slice
Net Plant @ 6/30/97 (a)	$ 6,714,898	$ 1,413,344	$ 151,558
Regulatory Assets - In Rates(b)	$ 2,610,510	$ 480,809	$ 51,559
Total Generation Costs in Rates	$ 9,325,408	$ 1,894,154	$ 203,117

(a) refer to Exhibit ABC- 7, page 2

(b) refer to Exhibit ABC - 7, page 3

PECO Energy Company
Revenue Requirement on Net Plant
As of June 30, 1997
($thousands)

Net Plant@ 6/30/97 (reference Exh ABC- 1,p.2)	$	6,714,898
Pre-Tax Return (reference Exh ABC - 7,p.4)		15.60%
Adjustment for future Tax Payouts(Exh ABC - 8)		96.43%
Revenue Requirement for Return	$	1,010,127
Annual Depreciation (a)	$	403,217
Total Revenue Requirement	$	1,413,344

Note: Gross receipts Tax of 4.4% is included in revenue requirement

(a) 1997 base depreciation (Exh ABC-1,p.2)	$	377,757
Plus Annualized Depreciation on 6/30/97 Capital additions (.5*5753*2)	$	7,718
Total Annualized Depreciation	$	385,475
Total w/GRT @ 4.4%	$	403,217

PECO Energy Company
Development OF Revenue Requirement
For Regulatory Assets
As of June 30, 1997
(thousand$)

Reg Assets	Bal @ 12/31/96	Annual Amort	Amort 1/1- 6/30	Bal @ 6/30/97		Return On	Ann. Rev Req
CC on 50% Limerick Common	$ 227,904	$ 26,046	$ 13,023	$ 214,881		$ 33,521	$ 60,766
Unamort Loss on Reacquired Debt(b)	$ 215,849	$ 18,072	$ 9,036	$ 206,813		$ 16,028	$ 34,932
Nuclear Design Basis Documentation	$ 31,899	$ 1,463	$ 732	$ 31,168		$ 4,862	$ 6,392
PB/Lim water chemistry systems	$ 7,507	$ 414	$ 207	$ 7,300		$ -	$ 433
Limerick 1 Declaratory order	$ 45,729	$ 13,714	$ 6,857	$ 38,872		$ -	$ 14,345
Limerick 2 Declaratory Order	$ 88,129	$ 10,072	$ 5,036	$ 83,093		$ -	$ 10,536
SFAS No. 106(c)	$ 130,513	$ 8,156	$ 4,078	$ 126,435		$ -	$ 8,531
Compensated Absences(c)	$ 20,925	$ 1,199	$ 600	$ 20,326		$ -	$ 1,254
SFAS No. 109	$ 1,919,352	$ 113,066	$ 56,533	$ 1,862,819	(a)	$ 221,437	$ 339,707
CC on 50% Common Salem/PB/Eddy	$ 19,272	$ 936	$ 468	$ 18,804		$ 2,933	$ 3,913
Total Regulatory Assets In Rates	$ 2,707,079	$ 193,138	$ 96,569	$ 2,610,510		$ 278,782	$ 480,809

(a) return only applies if asset is securitized
Calculation reflects a levelized return over the securitization period
since this asset is associated with taxes that have to be paid over
that period
Refer to Exhibit ABC - 7,p.5 for development of the amortization

Development of the Cost of Capital
For Use in Calculating the Rate Reduction
Based Upon Data at R-891364

	Capitalization Ratios	Cost Rates	Weighted Cost of Capital	Revenue Reqmt Level	
Debt	54.5%	10.38%	5.66%	5.66%	
Preferred	9.3%	10.19%	0.95%	1.62%	**WCC/(1-T); T= 41.493%**
Common	36.2%	12.75%	4.62%	7.89%	**WCC/(1-T); T= 41.493%**
Total	100.0%		11.22%	15.17%	
				15.86%	**w/GRT**

Note: Cost of equity is per PECO Energy's last rate case, R-891364

Adjusted Cost of Capital - Unamortized Loss on Reacquired Debt Adjustment is removed as it is included as a regulatory asset

	Capitalization Ratios	Cost Rates	Weighted Cost of Capital	Revenue Reqmt Level	
Debt	55.0%	10.04%	5.52%	5.52%	
Preferred	9.2%	10.13%	0.93%	1.59%	**WCC/(1-T); T= 41.493%**
Common	35.8%	12.75%	4.56%	7.80%	**WCC/(1-T); T= 41.493%**
Total	100.0%		11.02%	14.92%	
				15.60%	**w/GRT**

PECO Energy Company
Development of FAS 109 Amortization
Based Upon June 30, 1997
(thousand$)

Depreciation		**Base**		**Rev Reqmnt**	
Book Depreciation - annualized to 6/30/97	$	385,475	$	658,853	Base/(1-T)
Tax Depreciation - 1997	$	264,508	$	(187,588)	Base*T/(1-T)
Deferred Income taxes - plant related	$	(4,718)	$	(8,064)	Base/(1-T)
Total Depreciation Revenue Requirement			$	463,201	
Less: Book Depreciation			$	385,475	Exh. ABC-7,p.2
FAS 109 amortization for depreciation			$	77,726	
Other Regulatory Assets					
Limerick 1 Declaratory Order (a)			$	23,440	
Limerick 2 Declaratory Order (a)			$	17,215	
Deferred Carrying Charges and Depreciation on 50% Limerick Common(a)			$	44,518	
Total Other Regulatory Asset Revenue Reqmnt.			$	85,173	
Less: Annual Amortizations			$	49,832	
FAS 109 amortization for other Regulatory Assets			$	35,341	
Total FAS 109 Amortization			$	113,066	

Note: T = 41.493%

Note (a) - Annual amortization in Exhibit ABC-7, page 3 divided by (1-T)

PECO Energy Company
Calculation of Adjustment to Return Reduction
(thousand $)

Estimated Net Plant @ 6/30/97	$	6,714,898	Exhibit ABC-1,p.2
Estimated Accumulated Deferred Taxes 6/30/97	$	1,009,967	

Assuming that the entire net plant amount was securitized, the Company would receive the $6.7 billion in cash and have to pay out over the term of the transition bonds taxes equal to the accumulated deferred tax balance. As such it would be inappropriate to give a full ratebase credit for the cash received. Page two of this exhibit shows that the levelized accumulated deferred tax balance over the term of the transition bonds(assuming 10 years) is about 76.2% of the current accumulated deferred tax balance. The adjustment to the return on ratebase credit is calculated below.

Current Accumulated deferred taxes	$	1,009,967
Levelized accumulated deferred taxes	$	769,595
Reduction in ratebase offset	$	240,372
Total net plant	$	6,714,898
Less reduction for acc. deferred tax levelization	$	240,372
Base for return reduction	$	6,474,526
% of net plant		96.43%

PECO Energy Company
Illustration as to the Necessity for an Adjustment
To Accumulated Deferred Tax Ratebase Deduction

Assumptions:

Net Plant = $1,000,000
Accumulated Deferred Taxes = $414,930
Interest rate for securitization = 7%
Term of securitization bonds = 10 years
Remaining tax basis = $0
Remaining life = 10 years
Full $1,000,000 net plant is securitized

Year	Cash Flow	Annual ITC Rev	Interest	Principle/Amort	Unamort Princ	Income Taxes	Deferred Taxes	Acc. Def. Taxes
col 1	col 2	col 3	col 4	col 5	col 6	col 7 = col 5 *.41493	col 8 = - col 7	
0	1000000							$414,930
1	($30,033)	$142,380	$70,000	$72,380	$927,620	$30,033	($30,033)	$384,897
2	($32,135)	$142,380	$64,933	$77,447	$850,173	$32,135	($32,135)	$352,762
3	($34,384)	$142,380	$59,512	$82,868	$767,306	$34,384	($34,384)	$318,378
4	($36,791)	$142,380	$53,711	$88,669	$678,637	$36,791	($36,791)	$281,587
5	($39,367)	$142,380	$47,505	$94,875	$583,762	$39,367	($39,367)	$242,220
6	($42,122)	$142,380	$40,863	$101,517	$482,245	$42,122	($42,122)	$200,098
7	($45,071)	$142,380	$33,757	$108,623	$373,622	$45,071	($45,071)	$155,027
8	($48,226)	$142,380	$26,154	$116,226	$257,395	$48,226	($48,226)	$106,801
9	($51,602)	$142,380	$18,018	$124,362	$133,033	$51,602	($51,602)	$55,199
10	($55,214)	$142,380	$9,312	$133,068	($35)	$55,214	($55,214)	($14)
	$683,805.59							

Equivalent ADT	$	316,194
Initial ADT Bal	$	414,930
Adj. to RB Red.	$	(98,736)

In order to be neutral on a present value basis rate base should be reduced by $901,264.
This is equal to $1,000,000 less the $98,736 adjustment for accumulated deferred taxes.

PECO Energy Company
Illustrative Calculation of The
Impact of Securitizing Total Stranded Assets
(Thousand$)

Total Amount of Stranded Costs	$	7,135,486	
Estimated Revenue Requirement Reduction on Stranded Costs			
Total Stranded Cost Securitized	$	7,135,486	
Less: Decommissioning underfunding	$	556,906	(Exhibit ABC - 1)
Deferred Fuel - 1996(a)	$	96,162	
Deferred Fuel - Other(a)	$	143,300	
Assets Generating a Rate Reduction	$	6,339,118	
Revenue Reqmnt Reduction per $1 billion slice	$	203,117	(Exhibit ABC - 7, p.1)
Revenue Requirement Reduction	$	1,287,586	
Less: GRT on the ITC Revenue	$	51,335	
Net Revenue Requirement Reduction	$	1,236,251	(37.8%of net revenue)
Estimated Total ITC Revenue Requirement			
Assets Securitized	$	7,135,486	
Plus: Refunding Expense	$	502,430	
Issuance Expense	$	47,235	
Total Transition Bonds Issued	$	7,685,151	
Annual Payment @ 7.42%, 10 years	$	1,115,366	(34.1%of net revenue)
Net Rate Reduction for Customers	$	120,885	(3.7%of net revenue)

(a) present value @6/30/97

PECO Energy Company
Illustrative Calculation of The
Impact of Securitizing $3.6 Billion of Stranded Assets
(PECO Claim)
(Thousand$)

Total Amount of Stranded Costs	$	3,600,000	
Estimated Revenue Requirement Reduction on Stranded Costs			
Total Stranded Cost Securitized	$	3,600,000	
Less: Decommissioning underfunding	$	-	(Exhibit ABC - 1)
Deferred Fuel - 1996(a)	$	96,162	
Deferred Fuel - Other(a)	$	143,300	
Assets Generating a Rate Reduction	$	3,360,538	
Revenue Reqmnt Reduction per $1 billion slice	$	203,534	(Exhibit ABC - 10, p.3)
Revenue Requirement Reduction	$	683,985	
Less: GRT on the ITC Revenue	$	25,900	
Net Revenue Requirement Reduction	$	658,085	(20.1%of net revenue)
Estimated Total ITC Revenue Requirement			
Assets Securitized	$	3,600,000	
Plus: Refunding Expense	$	253,503	
Issuance Expense	$	23,833	
Total Transition Bonds Issued	$	3,877,336	
Annual Payment @ 7.42%, 10 years	$	562,728	(17.2%of net revenue)
Net Rate Reduction for Customers	$	95,357	(2.9%of net revenue)

(a) present value @6/30/97

PECO Energy Company
Allocation of the Rate Decrease/Increase

($thousand)

Rate Class	Peak Allocator R-891364 (1)	Energy Allocator R-891364 (2)	Wtd Peak/Energy Allocator - R-891364 (3) (b)	Securitization Rate Reduction (4)	ITC Increase(c) (5)	Net Rate Change (6) = (4) + (5)	Reallocation of Net Increases Modifies ITC (7)	Adjusted ITC Allocator (8) = (6) + (7)
R	27.41%	22.27%	27.07%	$ (180,386)	$ 152,325	$ (28,062)	$ 194	$ (27,868)
RH	5.47%	7.65%	5.62%	$ (35,997)	$ 31,618	$ (4,379)	$ 30	$ (4,349)
OP	0.00%	1.25%	0.08%	$ -	$ 468	$ 468	$ (468)	$ (0)
GS	19.26%	15.41%	19.00%	$ (126,747)	$ 106,919	$ (19,828)	$ 137	$ (19,691)
PD	4.99%	5.13%	5.00%	$ (32,838)	$ 28,158	$ (4,680)	$ 33	$ (4,647)
HT	41.00%	45.30%	41.28%	$ (269,815)	$ 232,322	$ (37,493)	$ 260	$ (37,233)
EP	1.86%	2.42%	1.89%	$ (12,240)	$ 10,651	$ (1,589)	$ 11	$ (1,578)
SLP	0.01%	0.30%	0.03%	$ (66)	$ 166	$ 100	$ (100)	$ 0
SLS	0.00%	0.15%	0.01%	$ -	$ 56	$ 56	$ (56)	$ 0
SLE	0.00%	0.06%	0.00%	$ -	$ 22	$ 22	$ (22)	$ -
Other Lighting	0.00%	0.05%	0.00%	$ -	$ 19	$ 19	$ (19)	$ (0)
Total(a)	100.00%	100.00%	100.00%	$ (658,085)	$ 562,728	$ (95,357)	$ -	$ (95,357)

Note (a) - reflects 100% of jurisdictional portion of peak allocator

(b) - the equivalent allocation factors when adjusting for column 6 are:

R	27.10%
RH	5.62%
GS	19.02%
PD	5.01%
HT	41.33%
EP	1.89%

(c) - Assumes approval of total Company claim and issuance of bonds at an effective rate of 7.42% with a 10-year maturity

PECO Energy Company
Revenue requirement included in Rates
For Stranded Investment
Estimate as of June 30 , 1997
(PECO Claim)
(Thousand $)

		Balance	% Total Balance		Total Revenue Reqmt		Rev Reqmt $1 billion Slice
Net Plant @ 6/30/97 (a)	$	6,714,898	72.4633%	$	1,413,344	$	152,520
Regulatory Assets - In Rates(b)	$	2,551,717	27.5367%	$	472,730	$	51,014
Total Generation Costs in Rates	$	9,266,615	100.0000%	$	1,886,074	$	203,534

(a) refer to Exhibit ABC- 7, page 2

(b) refer to Exhibit ABC - 10, page 4

PECO Energy Company
Development OF Revenue Requirement
For Regulatory Assets
As of June 30, 1997
(thousand$)

Reg Assets	Bal @ 12/31/96	Annual Amort	Amort 1/1- 6/30	Bal @ 6/30/97		Return On	Ann. Rev Req
CC on 50% Limerick Common	$ 227,904	$ 26,046	$ 13,023	$ 214,881		$ 33,521	$ 60,766
Unamort Loss on Reacquired Debt(b)	$ 215,849	$ 18,072	$ 9,036	$ 206,813		$ 16,028	$ 34,932
Nuclear Design Basis Documentation	$ -	$ -	$ -	$ -		$ -	$ -
PB/Lim water chemistry systems	$ -	$ -	$ -	$ -		$ -	$ -
Limerick 1 Declaratory order	$ 45,729	$ 13,714	$ 6,857	$ 38,872		$ -	$ 14,345
Limerick 2 Declaratory Order	$ 88,129	$ 10,072	$ 5,036	$ 83,093		$ -	$ 10,536
SFAS No. 106(c)	$ 130,513	$ 8,156	$ 4,078	$ 126,435		$ -	$ 8,531
Compensated Absences(c)	$ -	$ -	$ -	$ -		$ -	$ -
SFAS No. 109	$ 1,919,352	$ 113,066	$ 56,533	$ 1,862,819	(a)	$ 221,437	$ 339,707
CC on 50% Common Salem/PB/Eddy	$ 19,272	$ 936	$ 468	$ 18,804		$ 2,933	$ 3,913
Total Regulatory Assets In Rates	$ 2,646,748	$ 190,062	$ 95,031	$ 2,551,717		$ 273,920	$ 472,730

(a) return only applies if asset is securitized
Calculation reflects a levelized return over the securitization period since this asset is associated with taxes that have to be paid over that period
Refer to Exhibit ABC - 7,p.5 for development of the amortization

PECO Energy Company
Allocation of the Rate Decrease/Increase
($thousand)

Rate Class	Peak Allocator R-891364 (1)	Energy Allocator R-891364 (2)	Wtd Peak/Energy Allocator - R-891364 (3) (b)	Securitization Rate Reduction (4)	ITC Increase (5)	Net Rate Change (6) = (4) + (5)	Reallocation of Net Increases Modifies ITC (7)	Adjusted ITC Allocator (8) = (6) + (7)
R	27.41%	22.27%	27.24%	$ (338,866)	$ 303,804	$ (35,062)	$ 191	$ (34,871)
RH	5.47%	7.65%	5.55%	$ (67,623)	$ 61,871	$ (5,752)	$ 32	$ (5,720)
OP	0.00%	1.25%	0.04%	$ -	$ 468	$ 468	$ (468)	$ 0
GS	19.26%	15.41%	19.13%	$ (238,102)	$ 213,332	$ (24,770)	$ 136	$ (24,634)
PD	4.99%	5.13%	5.00%	$ (61,689)	$ 55,762	$ (5,927)	$ 32	$ (5,895)
HT	41.00%	45.30%	41.14%	$ (506,863)	$ 458,901	$ (47,962)	$ 262	$ (47,700)
EP	1.86%	2.42%	1.87%	$ (22,994)	$ 20,904	$ (2,090)	$ 11	$ (2,079)
SLP	0.01%	0.30%	0.02%	$ (124)	$ 222	$ 99	$ (99)	$ (0)
SLS	0.00%	0.15%	0.01%	$ -	$ 56	$ 56	$ (56)	$ 0
SLE	0.00%	0.06%	0.00%	$ -	$ 22	$ 22	$ (22)	$ -
Other Lighting	0.00%	0.05%	0.00%	$ -	$ 19	$ 19	$ (19)	$ (0)
Total(a)	100.00%	100.00%	100.00%	$ (1,236,251)	$ 1,115,366	$ (120,885)	$ -	$ (120,885)

Note (a) - reflects 100% of jurisdictional portion of peak allocator
(b) - the equivalent allocation factors when adjusting for column 6 are:

R =	27.26%
RH =	5.55%
GS =	19.15%
PD =	5.00%
HT =	41.16%
EP =	1.88%

Exhibit ABC - 11

PECO STATEMENT NO. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF A QUALIFIED RATE ORDER
UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

DIRECT TESTIMONY OF

STEPHEN R. XANDER

Regarding Rate Reduction Methodology, Reconciliations, Tariff Changes
and Customer Notice

TABLE OF CONTENTS

PAGE

DIRECT TESTIMONY OF
STEPHEN R. XANDER

I. INTRODUCTION

Q. Please state your name and business address.

A. Stephen R. Xander, 2301 Market Street, Philadelphia, Pennsylvania.

Q. By whom are you employed, Mr. Xander, and in what capacity?

A. I am employed by PECO Energy Company ("PECO") as Manager, Tariff Administration and Policy in the Rates & Regulatory Affairs Division.

Q. What is your educational background?

A. I received a Bachelor of Science degree in Business Administration from Drexel University in 1974. Additionally, I have completed the American Gas Association ("AGA") Gas Rate Fundamentals Course at the University of Wisconsin, the AGA Advanced Gas Rate Course at the University of Maryland and the Advanced Electric Rate Course sponsored by the Edison Electric Institute at Indiana University.

Q. Please describe your work experience with PECO.

A. Upon graduation from Drexel University in 1974, I was employed by PECO as a Tax Accountant in the Taxes Division. In 1982, I was promoted to Senior Tax Accountant. In these positions my job responsibilities included tax planning, research, legislative analysis and providing support for PECO's tax claims in rate proceedings.

In 1990, I was appointed to the position of Assistant to the Controller. In this position my job responsibilities included the planning and implementation of financial controls and the development of accounting systems.

In 1991, I was appointed Supervisor of Accounting Controls, Budget and Control Division, with responsibility for preparing and analyzing financial information and implementing accounting control procedures.

In 1992, I was appointed Supervisor, Gas Rates. After the Rate Division was reorganized in 1995, I was appointed Manager, Tariff Administration and Policy. My primary responsibility is the administration of the Company's electric and gas tariffs, including calculation of the annual fuel, tax and other surcharge mechanisms. My responsibilities also include coordinating the development of new electric and gas rates and the preparation of financial information supporting the new rates.

Q. Have you testified previously in any regulatory proceedings?

A. Yes, I testified before the PUC in the Limerick 2 rate case (Docket No. R-891364) with respect to the Company's tax claim.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the methodology to be used in applying to customers' bills the net rate reductions that will result from the securitization process. I will also discuss reconciliations, necessary tariff changes and customer notice.

II. *RATE REDUCTION METHODOLOGY*

Q. Please describe the overall methodology by which PECO proposes to apply the securitization rate reduction to customers' bills.

A. The net rate reduction will result from replacing the revenue requirement associated with PECO's Transition or Stranded Costs (e.g. generating plant and regulatory assets) with the lower revenue requirement that would be imposed by the Intangible Transition Charge (ITC). As such, it is a two-step process. First, rates for each class must be reduced by the appropriate amount, referred to in my testimony as the Securitization Rate Reduction (SRR). Second, the ITC amount necessary to fund the Transition Bonds must be collected. The allocation of the SRR and the ITC revenue requirement among rate classes is addressed by Mr. Cohn. As Mr. Cohn explains, the SRR and ITC are allocated on the basis of the appropriate allocation factors used for similar cost categories in the cost-of- service study presented by PECO in its Limerick 2 rate case (Docket No. R-891364). Such allocation for PECO's claim is shown on Exhibit ABC-11.

The net effect of the SRR and ITC will be shown on the customer bill as the Net Securitization Adjustment (NSA). Each component of the NSA will be shown in a description field on the bill, but the net NSA amount will be shown as a credit in the total

column. Using illustrative data, Exhibit SRX-1 shows how this would appear on the monthly bill for a residential customer (Rate R) using 500 kWh, a General Service customer (Rate GS) using 3,500 kWh at 20 kW of billing demand and a High Tension (HT) customer using 250,000 kWh at 750 kW of billing demand.

Q. Within this overall methodology, how will the SRR and ITC components be calculated?

A. The SRR and ITC values will each be calculated as a percentage of expected total base rate revenue to be collected by rate class. (Billed but uncollectible revenue will be excluded from the denominator in the calculation so as not to undercollect the ITC). These percentages will be applied to customers' total base bills to determine the components of the NSA. Exhibit SRX-2 demonstrates the calculation of the percentages by rate class using illustrative data.

Q. Why did the Company select the percentage-of-revenue methodology?

A. There are four significant reasons for selecting the "percentage-of-revenue" methodology.

First, the decrease (SRR) and increase (ITC) are reflected as percentages of the total bill, which preserves the underlying rate structure embedded in the current rate design for each rate class. This ensures there is no cost shifting within a customer class as required in

Section 2812 (G) of the Electricity Generation Customer Choice and Competition Act (the "Competition Act").

Second, it is a straight-forward method that should enhance customer understanding by clearly showing the rate reduction benefit. This is evident from the sample bills provided in Exhibit SRX-1.

Third, PECO's current billing system can accommodate the necessary changes within the time period required to implement the NSA.

Finally, as I will discuss later, the method can be readily adapted and applied to unbundled bills in the future.

Q. Did the Company consider other methods for applying the NSA to customers' bills?

A. Yes. The Company considered two alternatives to the percentage-of-revenue method that were rejected because of intra-class cost shifting issues.

First, the Company considered a fixed customer credit and charge for implementing the SRR and ITC, respectively, which would have been based on historic customer-usage profiles. This method provides a nearly fixed revenue stream to amortize the Transition Bond obligations. However, it also has significant disadvantages. For example, to minimize the potential cost shifting within a rate class, a complex matrix would have to be

developed to segment customers by historic usage profiles. For non-residential customers, demand would also have to be factored into the matrix. This approach was determined to be prohibitively complex to implement and explain to customers. It also has the disadvantage of being unable to readily accommodate a customer's change in usage pattern.

The Company also considered a usage-based (cents per kWh) methodology. Although relatively simple to implement, this method could result in significant intra-class cost shifting because PECO's existing rate structure does not recover the fixed costs of generation assets on a level cents per kWh basis. This concept is most apparent for non-residential classes, where measured demand affects the overall price per kWh the customer pays. Therefore, since cost responsibility for generation assets is not based on a level charge per kWh, neither should the SRR and ITC.

The percentage-of-revenue method overcomes the defects inherent in a usage-based (cents per kWh) method because, in effect, it changes each component of the customer's bill by a percentage.

Q. Please describe how the percentage-of-revenue methodology would be adapted when rate unbundling occurs.

A. Customers' bills will show prices separately for market-based generation, transmission and distribution, and the recovery of Transition or Stranded Costs through a Competitive

Transition Charge (CTC). The total dollar amounts of the SRR and the ITC assigned to each rate class will not be affected by the unbundling. However, instead of calculating the SRR and ITC as percentages of the total class revenue, they would be calculated as percentages of the sum of the unbundled billing components, excluding the market price of generation. This is illustrated by Exhibit SRX-3, which shows the calculation of the NSA in a hypothetical, unbundled environment using the same total revenue shown on Exhibit SRX-2. Comparing the Proof of Revenue portions of Exhibit SRX-2 to Exhibit SRX-3 shows that the amount of the rate reduction by rate class would not change between the "bundled" and "unbundled" scenarios.

Q. What assurance will the Transition Bondholders have that the ITC can be collected in an environment where customers can choose generation suppliers?

A. The Competition Act mandates that the distribution, transmission and generation components be unbundled on customers' bills. While the customer will be able to choose a generation supplier, the local distribution company will continue to charge for distribution and transmission services as well as the CTC and ITC. The ITC collection will be dependent on customers' usage as evidenced by billing determinants (energy and demand), but will not be affected by choosing another generation supplier.

Q. Will the rates of any customers be unaffected by the asset securitization process?

A. As shown in Mr. Cohn's Exhibit ABC-11, under current rates not all customer classes are assigned cost responsibility for generation assets. Accordingly, these classes do not share in any rate reductions afforded by the securitization of the generation assets, nor do they bear cost responsibility for recovery of any stranded cost of generation. Rate classes so identified include Rate OP, SL-P, SL-S, SL-E and Other Lighting.

Further, a customer making use of a rider, including an Economic Efficiency Rider (EER) contract, Incremental Process Rider (IPR) contract, or a special contract under Rule 4.6 of PECO's electric tariff, will be affected only to the extent the rate provisions of the rider or contract are directly linked to the rates contained in Rates GS, PD or HT (except for contracts effective on or after December 31, 1996 that provide otherwise). Therefore, those customers (currently less than ten in number) with contracts authorized by tariff Rule 4.6, the EER, or the IPR that contain rates that are not directly linked to Rates GS, PD or HT will receive no rate decrease associated with securitization.

III. RECONCILIATIONS

Q. How will the ITC be reconciled?

A. When Transition Bonds are issued as part of the process of securitizing PECO's Qualified Transition Expenses (QTE), an amortization schedule showing "Projected QTE Principal Balances" as of certain dates that may reflect quarterly, semi-annual or annual reconciliation periods over the term of the Transition Bonds will be established. Periodically, on a designated "True-Up Date," PECO will determine the actual

unamortized QTE Principal Balance and will compare this balance with the Projected QTE Principal Balance for such date. If these balances differ by more than a specified percentage ("Allowable Percentage") to be determined before the bonds are issued, PECO will adjust the ITC percentage accordingly (if, for example, the allowable percentage were 0%, an ITC adjustment would be likely to occur on each true-up date). In calculating the adjusted ITC percentage, PECO will use its then-current assumptions regarding customer billings, charge-offs, and any other relevant parameters.

The adjusted ITC percentage will be calculated to produce the level of ITC revenue that will make the actual unamortized QTE Principal Balance at the next True-Up Date equal to the Projected QTE Principal Balance at that date. Specifications for the timing and implementation of the adjustment process will have to await the completion of the transaction documents for the sale of PECO's Intangible Transition Property and the issuance of the Transition Bonds. Exhibit SRX-4 shows how the proposed true-up mechanism will work in concept. The Company will provide all of the reconciliation and true-up calculations to the Commission based on the terms and conditions of the Transition Bond sale. The Company proposes that any true-up adjustment to the ITC become effective upon 10-days notice to the Commission subject to the annual reconciliation process envisioned in Section 2812 (B) of the Competition Act.

Q. Does the Competition Act provide for such a reconciliation process?

A. Yes, Section 2812 (B) of the Competition Act provides that, in addition to an annual review based on the anniversary date of the issuance of the Qualified Rate Order (QRO), adjustments may be made at ". . . additional intervals as may be provided in the Qualified Rate Order." More frequent true-ups will provide more certainty to the ITC revenue stream which is an important consideration in establishing the credit quality and price of the Transition Bonds. The Company is, therefore, requesting that the QRO provide this flexibility in allowing more frequent reconciliations as may be required under terms and conditions of the Transition Bond offerings.

Q. How will the true-up mechanism work if the Transition Bonds are not all issued at the same time?

A. Each Transition Bond issue will be reconciled individually because the Transition Bond issues will likely have different amortization schedules, and different interest rates. However, the results of each individual true-up will be added together to determine the total amount of ITC needed to be collected over the next reconciliation period. Accordingly, only one set of ITC values will be reflected in the tariff and on customers' bills.

Q. Will the reconciliation be performed on a class-by-class basis or a Company-wide basis?

A. While the SRR and ITC values will be determined on a class-by-class basis, reconciliations will be made on a total Company basis. The Company-wide approach significantly

reduces administrative complexity associated with the true-ups which may be as frequent as quarterly.

Q. How will the Company-wide ITC reconciliation affect the ITC values for each rate class?

A. The Company-wide reconciliation will identify the total amount of ITC needed to be recovered by the end of the next True-Up Date. This amount will be allocated to each rate class just as the original ITC was allocated using the appropriate allocation factors shown on Exhibit ABC-10 (page 2 of 4). An illustration of this methodology and its application is provided in Exhibit SRX-5.

Q. Should the Qualified Rate Order allow for any subsequent changes in the ITC *reconciliation methodology?*

A. Yes, the Order should provide sufficient flexibility to ensure that ITC recovery will occur even if unusual situations are encountered in the future. For example, in the possible, but unlikely, event that an entire rate class faces extinction, the associated ITC responsibility would have to be assumed by the remaining rate classes. The Company requests that if a change to the reconciliation methodology becomes necessary to ensure full recovery of QTE, the Commission will act upon the request filed to implement that change within 90 days.

Q. Is the Company proposing any other reconciliation process in this filing?

A. Yes, as discussed in Mr. Mitchell's testimony, a true-up of costs associated with issuing the Transition Bonds and use of proceeds will be necessary. For reasons explained by Mr. Mitchell, this reconciliation must be completely independent of the ITC true-up procedure. Therefore, we are recommending that a separate adjustment mechanism such as provided for under Section 1307 (a) of the Code be utilized for truing up such costs.

Q. Please discuss the proposed 1307 (a) mechanism.

A. In general, the mechanism, to be referred to as the Transition Bond Expense Adjustment (TBEA), would be calculated using a methodology that is consistent with the NSA methodology. Any such adjustment to be collected or refunded to customers would be allocated to each appropriate rate class based on the Exhibit ABC-10 (page 2 of 4) factors. In the case of a refund, an interest component would be included calculated using the maximum allowable mortgage lending rates published in the *Pennsylvania Bulletin*. The TBEA amount would then be expressed as a percentage of expected total base rate revenue to be collected by rate class. These percentages would be applied to customers' total base bills to determine the additional collection or refund amount.

Q. Please discuss the timing of the implementation of the TBEA.

A. The Company proposes that the TBEA be implemented after Commission approval on 60 days notice. Such a filing would be made after all refinancings authorized by the Qualified Rate Order have taken place and all costs are known.

Q. Over what period would the recovery or refund occur?

A. The Company anticipates recovery or refund over a 12 month period; however, the Company may request a longer period in a situation where it is seeking to recover amounts .

IV. TARIFF CHANGES

Q. What tariff revisions are necessary to implement the effects of the SRR and ITC?

A. A copy of the proposed tariff supplement to implement the NSA and TBEA is provided in Exhibit 7 to PECO's Application. I have also included a portion of the tariff (pages 31A and 31B) as Exhibit SRX-6 for reference. Tariff page 31A describes the application of the NSA and will provide all relevant rate values. Tariff Page 31B describes the application of the TBEA and will provide all relevant values. Each electric rate in PECO's Supplement No. 11 to Electric Tariff No. 2 then refers to the NSA and the TBEA.

V. CUSTOMER NOTICE

Q. What form of notice will be given of PECO's filing to obtain a Qualified Rate Order?

A. Sections 2808 and 2812 of the Competition Act are silent with respect to the form and nature of notice to be provided to customers. However, to ensure that its customers are made aware of this filing as soon as possible, PECO, following discussions with Commission Staff and representatives of the Office of Consumer Advocate, began including bill inserts (Exhibit SRX-7) in the form attached as Exhibit 8 to the Application,

commencing with bills issued on or after January 23, 1997. In addition, contemporaneous with this filing, PECO is publishing notice of this Application in newspapers of general circulation in its service territory, posting the notice in its business office at 2301 Market Street, Philadelphia, Pennsylvania, and proposes that notice also be published in the *Pennsylvania Bulletin* as soon as possible. Finally, PECO is serving copies of this filing on the Offices of Trial Staff, the Consumer Advocate and Small Business Advocate and the Philadelphia Area Industrial Energy Users Group, and is providing immediate notice of its Application to all of the other parties which actively participated in the Limerick 2 rate case and to all of the non-legislative members on the Commission's Monday Group Stakeholder list.

VI. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

PECO Energy Company

500 kWh Residential - Rate R

Bundled Summer Bill Demonstration[(1)]

Customer Charge	$5.10
Energy Charge	
1st 500 kWh [500 kWh x $0.1305]	$65.25
Base Bill	**$70.35**
NSA = SRR + ITC = [($12.47) + $10.54]	**($1.93)**
Total Bill	**$68.42**
Percentage Change	**(2.7%)**

NOTE: (1) Demonstration assumes $3,877,336,000 of bonds issued at 7.42% interest rate with a 10 year maturity.

PECO Energy Company

20 kW, 3500 kWh Commercial - Rate GS

Bundled Summer Bill Demonstration

Customer Charge	$23.45
Energy Charge	
1st block (80 hrs use) [1600 kWh x $0.2214]	$354.24
2nd block (80 hrs use) [1600 kWh x $0.1124]	$179.84
Last block (remaining use) [300 kWh x $0.0767]	$23.01
Base Bill	**$580.54**
NSA = SRR + ITC = [($96.88) + $81.83]	**($15.05)**
Total Bill	**$565.49**
Percentage Change	**(2.6%)**

NOTE: (1) Demonstration assumes $3,877,336,000 of bonds issued at 7.42% interest rate with a 10 year maturity.

PECO Energy Company

750 kW, 250,000 kWh Industrial - Rate HT

Bundled Summer Bill Demonstration

Customer Charge	$286.86
Capacity Charge (750 kw x $12.76)	$9,570.00
Energy Charge	
1st block (150 hrs use) [112,500 kWh x $0.0829]	$9,326.25
2nd block (150 hrs use) [112,500 kWh x $0.0550]	$6,187.50
Last block (remaining use) [25,000 kWh x $0.0274]	$685.00
Base Bill	**$26,055.61**
NSA = SRR + ITC = [($7,882.73) + $6,794.96]	**($1,087.77)**
Total Bill	**$24,967.84**
Percentage Change	**(4.2%)**

NOTE: (1) Demonstration assumes $3,877,336,000 of bonds issued at 7.42% interest rate with a 10 year maturity.

PECO Energy Company

Securitization Rate Calculation Demonstration - Bundled Scenario[1]

($1,000)

	R[2]	RH	OP	GS	PD	HT	HT-Special Contracts	POL	SL-P	SL-S	SL-E	TL	EP	TOTAL
Total Revenue	$ 1,063,459	$ 277,427	$ 27,323	$ 771,067	$ 124,686	$ 893,749	$ 125,944	$ 2,166	$ 15,112	$ 6,886	$ 8,021	$ 5,014	$ 20,378	$ 3,341,232
less: Uncollectable Accounts	$ 45,400	$ 10,989	$ 1,220	$ 11,535	$ 920	$ 1,902	$ 0	$ 17	$ 0	$ 0	$ 0	$ 17	$ 0	$ 72,000
Net Revenue	$ 1,018,059	$ 266,438	$ 26,103	$ 759,532	$ 123,766	$ 891,847	$ 125,944	$ 2,149	$ 15,112	$ 6,886	$ 8,021	$ 4,997	$ 20,378	$ 3,269,232
Securitization Reduction	$ (180,386)	$ (35,997)	$ 0	$ (126,747)	$ (32,838)	$ (269,815)	$ 0	$ 0	$ (66)	$ 0	$ 0	$ 0	$ (12,240)	$ (658,085)
Intangible Transition Cost	$ 152,519	$ 31,648	$ 0	$ 107,056	$ 28,191	$ 232,582	$ 0	$ 0	$ 66	$ 0	$ 0	$ 0	$ 10,662	$ 562,728
Net Securitization Adjustment	$ (27,868)	$ (4,349)	$ 0	$ (19,691)	$ (4,647)	$ (37,233)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (1,578)	$ (95,357)
Securitization Reduction Rate[3]	(17.7186%)	(13.5104%)	0.0000%	(16.6875%)	(26.5324%)	(30.2535%)	0.0000%	0.0000%	(0.4367%)	0.0000%	0.0000%	0.0000%	(60.0648%)	(20.1297%)
Intangible Transition Charge[4]	14.9813%	11.8782%	0.0000%	14.0950%	22.7777%	26.0787%	0.0000%	0.0000%	0.4367%	0.0000%	0.0000%	0.0000%	52.3211%	17.2128%
Net Securitization Adjustment	(2.7373%)	(1.6322%)	0.0000%	(2.5925%)	(3.7547%)	(4.1748%)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	(7.7437%)	(2.9169%)
Proof of Revenue:														
Net Revenue	$ 1,018,059	$ 266,438	$ 26,103	$ 759,532	$ 123,766	$ 891,847	$ 125,944	$ 2,149	$ 15,112	$ 6,886	$ 8,021	$ 4,997	$ 20,378	$ 3,269,232
NSA Rate	(2.7373%)	(1.6322%)	0.0000%	(2.5925%)	(3.7547%)	(4.1748%)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	(7.7437%)	(2.9168%)
NSA Revenue	$ (27,868)	$ (4,349)	$ 0	$ (19,691)	$ (4,647)	$ (37,233)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (1,578)	$ (95,357)

NOTE: (1) Demonstration assumes $3,877,336,000 of bonds issued at 7.42% interest rate with a 10 year maturity
(2) Rate R includes R, RT, CAP, R-S and BLI
(3) Securitization Reduction ÷ Net Revenue
(4) Intangible Transition Cost ÷ Net Revenue

Exhibit SRX - 2

PECO Energy Company

Securitization Rate Calculation Demonstration - Unbundled Scenario[1]

($1,000)

	R[2]	RH	OP	GS	PD	HT	HT-Special Contracts	POL	SL-P	SL-S	SL-E	TL	EP	TOTAL
Customer Charge	$ 72,767	$ 9,221	$ 1,520	$ 25,481	$ 4,746	$ 7,009	$ 2,398	$ 41	$ 285	$ 131	$ 153	$ 95	$ 160	$ 124,008
Distribution	$ 327,147	$ 75,358	$ 12,425	$ 97,251	$ 8,556	$ 37,601	$ 12,864	$ 219	$ 1,528	$ 703	$ 819	$ 510	$ 859	$ 575,841
Transmission	$ 45,071	$ 9,457	$ 1,559	$ 39,549	$ 6,302	$ 53,331	$ 18,245	$ 311	$ 2,167	$ 998	$ 1,162	$ 724	$ 1,219	$ 180,094
Sub-Total	$ 444,985	$ 94,036	$ 15,505	$ 162,281	$ 19,604	$ 97,941	$ 33,507	$ 572	$ 3,981	$ 1,832	$ 2,134	$ 1,329	$ 2,238	$ 879,943
CTC														
Demand	$ 0	$ 0	$ 0	$ 0	$ 22,851	$ 209,222	$ 0	$ 0	$ 151	$ 0	$ 0	$ 0	$ 4,781	$ 237,005
Energy	$ 398,949	$ 108,125	$ 0	$ 441,504	$ 51,195	$ 314,488	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,186	$ 1,321,448
CTC Total[3]	$ 398,949	$ 108,125	$ 0	$ 441,504	$ 74,046	$ 523,710	$ 0	$ 0	$ 151	$ 0	$ 0	$ 0	$ 11,941	$ 1,558,453
LDU Revenue	$ 843,935	$ 202,162	$ 15,505	$ 603,785	$ 93,650	$ 621,651	$ 33,507	$ 572	$ 4,132	$ 1,832	$ 2,134	$ 1,329	$ 14,179	$ 2,438,396
Market Energy	$ 174,125	$ 64,277	$ 10,598	$ 155,747	$ 30,115	$ 270,197	$ 92,437	$ 1,577	$ 10,980	$ 5,054	$ 5,887	$ 3,667	$ 6,174	$ 830,835
Net Revenue	$ 1,018,059	$ 266,438	$ 26,103	$ 759,532	$ 123,766	$ 891,847	$ 125,944	$ 2,149	$ 15,112	$ 6,886	$ 8,021	$ 4,997	$ 20,353	$ 3,269,231
SRR Revenue[4]	$ (180,386)	$ (35,997)	$ 0	$ (126,747)	$ (32,838)	$ (269,815)	$ 0	$ 0	$ (66)	$ 0	$ 0	$ 0	$ (12,240)	$ (658,085)
ITC Revenue[5]	$ 152,519	$ 31,648	$ 0	$ 107,056	$ 28,191	$ 232,582	$ 0	$ 0	$ 66	$ 0	$ 0	$ 0	$ 10,662	$ 562,728
NSA Revenue	$ (27,868)	$ (4,349)	$ 0	$ (19,691)	$ (4,647)	$ (37,233)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (1,578)	$ (95,357)
SRR Rate	(21.3744%)	(17.8060%)	0.0000%	(20.9921%)	(35.0645%)	(43.4030%)	0.0000%	0.0000%	(1.5973%)	0.0000%	0.0000%	0.0000%	(86.3263%)	(26.9884%)
ITC Rate	18.0724%	15.6548%	0.0000%	17.7308%	30.1024%	37.4136%	0.0000%	0.0000%	1.5973%	0.0000%	0.0000%	0.0000%	75.1970%	23.0778%
NSA Rate	(3.3020%)	(2.1512%)	0.0000%	(3.2613%)	(4.9621%)	(5.9894%)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	(11.1293%)	(3.9106%)
Proof of Revenue:														
LDU Revenue	$ 843,935	$ 202,162	$ 15,505	$ 603,785	$ 93,650	$ 621,651	$ 33,507	$ 572	$ 4,132	$ 1,832	$ 2,134	$ 1,329	$ 14,179	$ 2,438,396
NSA Rate	(3.3020%)	(2.1512%)	0.0000%	(3.2613%)	(4.9621%)	(5.9894%)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	(11.1293%)	(3.9106%)
NSA Revenue	$ (27,868)	$ (4,349)	$ 0	$ (19,691)	$ (4,647)	$ (37,233)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (1,578)	$ (95,357)

NOTE: (1) Demonstration assumes $3,877,336,000 of bonds issued at 7.42% interest rate with a 10 year maturity

(2) Rate R includes R, RT, CAP, R-S and BLI

(3) In the absence of an actual CTC component, the final effective CTC rate values will be carried forward to be used only as a computational basis for the ongoing ITC while not themselves being applied to customers' bills.

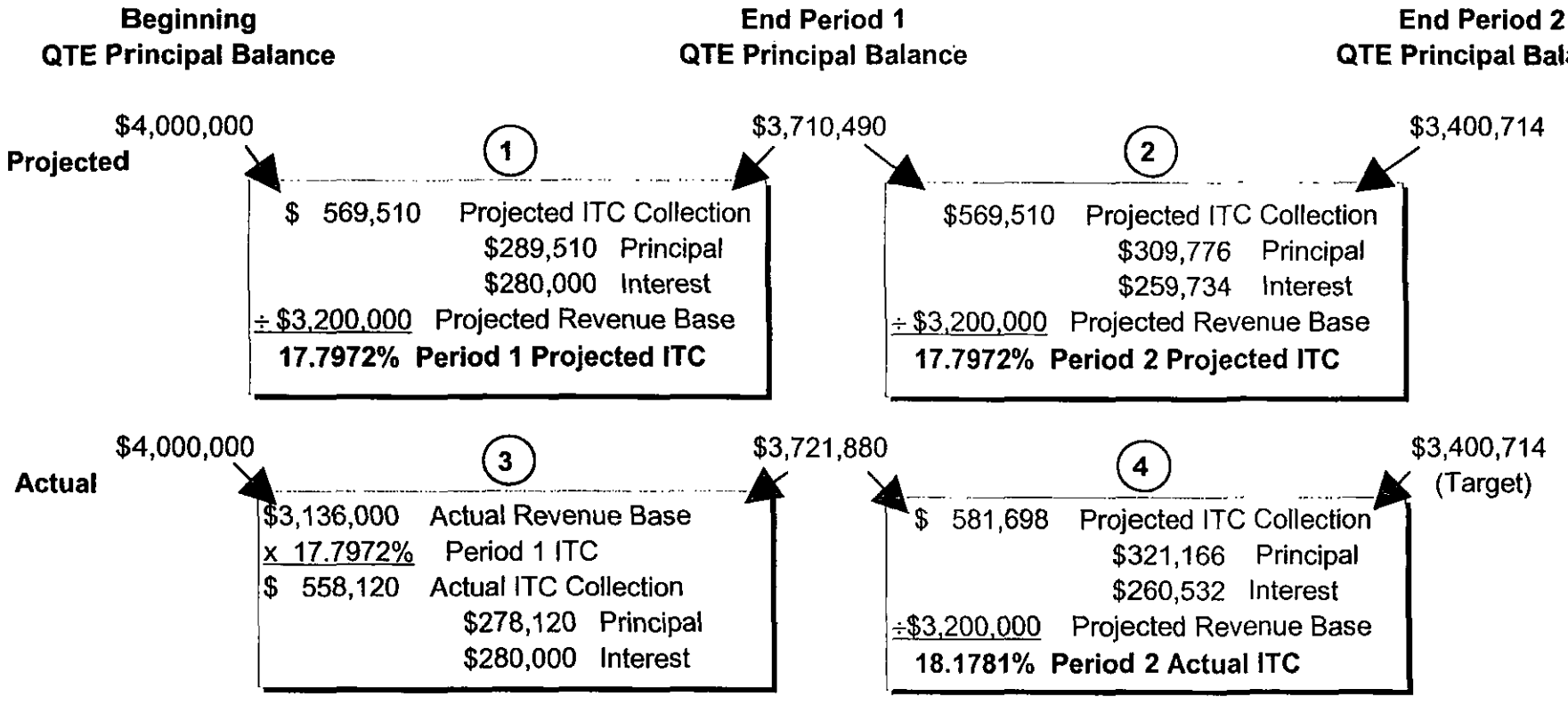
(4) SRR Revenue ÷ Local Distribution Utility (LDU) Revenue

(5) ITC Revenue ÷ Local Distribution Utility (LDU) Revenue

Exhibit SRX - 3

Reconciliation Methodology Demonstration Based on Qualified Transition Expense (QTE) Principal Balance

($1,000)



1. Taking the initial balance of $4,000,000 and amortizing it over 10 periods at a 7% interest rate, the periodic payments will equal $569,510. This payment for Period 1 is broken down between principal and interest as shown. Dividing the total payment over the projected periodic revenue of $3,200,000 gives an ITC rate of 17.7972%.
2. Assuming perfect Period 1 collection and a steady revenue base, the Period 2 ITC will remain the same.
3. If, for instance, revenues were 2% below projected, ITC collection would also be 2% below projected. Because of the lower payment, the principal payment and therefore principal balance reduction, is lower in order to pay bond holders the full period's interest on the initial balance.
4. In order to meet the initially projected end of Period 2 principal balance of $3,400,714, Period 2's payment must increase to make up for Period 1 shortfalls. This new payment level must collect enough to reduce the principal balance to the desired level by the end of Period 2 and to collect the higher interest than originally projected for Period 2 due to the greater principal balance outstanding during the Period.

Reconciliation Methodology Demonstration Based on Qualified Transition Expense (QTE) Principal Balance

($1,000)

PERIOD 1

	Originally Projected	Actual
Total ITC Revenue	$569,510	$558,120

Rate Class	ABC-10 Allocator	Projected ITC Revenue	Actual ITC Revenue
R	27.12%	$154,451	$151,362
RH	5.62%	$32,006	$31,366
OP	0.00%	$0	$0
GS	19.04%	$108,435	$106,266
PD	5.01%	$28,532	$27,962
HT	41.31%	$235,265	$230,559
HT-SC	0.00%	$0	$0
POL	0.00%	$0	$0
SL-P	0.00%	$0	$0
SL-S	0.00%	$0	$0
SL-E	0.00%	$0	$0
TL	0.00%	$0	$0
EP	1.89%	$10,764	$10,548
		$569,453	$558,120

1. Period 1 ITC revenue is projected to be $569,510.
2. ITC revenue allocated to individual rate classes.
3. Because of lower total revenue, the actual Period 1 ITC revenue is lower than projected.
4. Period 1's undercollection causes the need for a greater Period 2 ITC which is allocated to the individual rate classes as before.

PERIOD 2

	Originally Projected	Actual
Total ITC Revenue	$569,510	$581,698

Rate Class	ABC-10 Allocator	Projected ITC Revenue	Actual ITC Revenue
R	27.12%	$154,451	$157,756
RH	5.62%	$32,006	$32,691
OP	0.00%	$0	$0
GS	19.04%	$108,435	$110,755
PD	5.01%	$28,532	$29,143
HT	41.31%	$235,265	$240,299
HT-SC	0.00%	$0	$0
POL	0.00%	$0	$0
SL-P	0.00%	$0	$0
SL-S	0.00%	$0	$0
SL-E	0.00%	$0	$0
TL	0.00%	$0	$0
EP	1.89%	$10,764	$10,994
		$569,453	$581,698

Exhibit SRX - 5

SUPPLEMENT NO. 11 TO
TARIFF ELECTRIC PA. P.U.C. NO. 2

PECO Energy Company

ORIGINAL PAGE NO. 31A

NET SECURITIZATION ADJUSTMENT (NSA) (C)

In addition to the net charges provided for in this tariff, values as indicated in the table below will be applied to service on and after xxx xx, 1997.

The NSA is comprised of two separate factors, the Securitization Rate Reduction and the Intangible Transition Charge. The factors as described below will become effective on 10 days notice to the Commission.

Securitization Rate Reduction (SRR)

The SRR is a credit to the Company's base rate charges, expressed as a percentage of such charges, reflecting a revenue requirement reduction arising from the Company's securitization of generation-related costs pursuant to Sections 2808 and 2812 of the Pennsylvania Public Utility Code. The SRR will be recalculated whenever the level of revenue requirement reduction due to the level of asset securitization changes, as evidenced by the issuance date the of the Transition Bonds.

Intangible Transition Charge (ITC)

The ITC is a charge that is added to, and expressed as a percentage of, the Company's base rate charges reflecting the revenue requirement necessary to amortize the Qualified Transition Expense (QTE) principal balance. The ITC will be recalculated:

(1) whenever new Transition Bonds are issued as evidenced by the issuance date of the bonds.

(2) periodically, to reconcile unamortized QTE principal balance, as mandated by the terms and conditions of the Transition Bond agreements.

Effective Rate Table

Rate Class	SRR	ITC	NSA
R	xx.xxxx%	xx.xxxx%	xx.xxxx%
RT	xx.xxxx%	xx.xxxx%	xx.xxxx%
R-H	xx.xxxx%	xx.xxxx%	xx.xxxx%
CAP	xx.xxxx%	xx.xxxx%	xx.xxxx%
OP	—	—	—
R-S	xx.xxxx%	xx.xxxx%	xx.xxxx%
GS	xx.xxxx%	xx.xxxx%	xx.xxxx%
PD	xx.xxxx%	xx.xxxx%	xx.xxxx%
HT	xx.xxxx%	xx.xxxx%	xx.xxxx%
POL	—	—	—
SL-P	—	—	—
SL-S	—	—	—
SL-E	—	—	—
TL	—	—	—
BLI	xx.xxxx%	xx.xxxx%	xx.xxxx%
EP	xx.xxxx%	xx.xxxx%	xx.xxxx%

(C) Denotes Change

TRANSITION BOND EXPENSE ADJUSTMENT (TBEA) (C)

In addition to the net charges provided for in this tariff, values as indicated in the table below will be applied to all service on and after xxx 1997. The TBEA will become effective on 60 days notice to the Commission and will be subject to an annual reconciliation and review process.

The TBEA provides a reconciliation mechanism to collect or refund the difference between estimated Transition Bond expenses that have been incorporated into the issuance of Transition Bonds being recovered in the Intangible Transition Charge and the actual Transition Bond expenses. Transition Bond expenses are defined as expenses associated with the issuance of and use of proceeds from Transition Bonds.

Effective Rate Table

Rate Class	TBEA
R	xx.xxxx%
RT	xx.xxxx%
R-H	xx.xxxx%
CAP	xx.xxxx%
OP	—
R-S	xx.xxxx%
GS	xx.xxxx%
PD	xx.xxxx%
HT	xx.xxxx%
POL	—
SL-P	—
SL-S	—
SL-E	—
TL	—
BLI	xx.xxxx%
EP	xx.xxxx%

(C) Denotes Change

PECO ENERGY COMPANY REQUESTS PaPUC APPROVAL OF A RATE DECREASE IN PREPARATION FOR ELECTRIC COMPETITION

The Pennsylvania Legislature recently passed and Governor Ridge signed a law that will begin to allow customers to choose their electric generation supplier by 1999 with all customers provided choice by 2001. That law provides utilities the opportunity to seek recovery of certain transition costs and to refinance some of their property, passing the savings associated with refinancing on to customers in the form of reduced rates.

PECO Energy has filed with the Pennsylvania Public Utility Commission (PaPUC) to refinance approximately $3.6 billion of such property (plus associated costs of refinancing.) Subject to PaPUC approval, this amount of refinancing will result in an estimated $95 million overall decrease in customer rates, or approximately 2.9%, depending on market interest rates at the time of the refinancing. The monthly bill for a typical residential customer using 500 kWh would decrease by $1.93, or 2.7%.

For more information contact PECO Energy at 1-800-494-4000. You may contact the PaPUC at P. O. Box 3265, Harrisburg, Pennsylvania, 17105-3265 within 15 days of receipt of this notice if you wish to file a complaint or participate in the proceedings.

PECO Energy Company

January/February 1997

R-00973953
PECO Restructuring Application
Phila. 1/14/15/16/97
E. Colbert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF QUALIFIED RATE ORDER
UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

VOLUME II

January 22, 1997