COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE
1425 Strawberry Square
Harrisburg, Pennsylvania 17120

IRWIN A. POPOWSKY
Consumer Advocate

(717) 783-5048

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PROTHONOTARY'S OFFICE

January 9, 1998

James J. McNulty, Secretary
Secretary Bureau
Pennsylvania Public Utility Commission
Room B-20, North Office Building
P. O. Box 3265
Harrisburg, PA 17105-3265

DOCUMENT FOLDER

KJR

Re: Application of Duquesne Light Company for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code,
Docket No. R-00974104

Dear Secretary McNulty;

Pursuant to the Administrative Law Judge's Sixth Interim Order, enclosed please find for filing 2 copies of the Office of Consumer Advocate's Direct, Rebuttal and Surrebuttal Testimonies in the above-captioned proceeding. We have also enclosed a signed copy of the First Joint Stipulation regarding intervenor testimony. Copies of all our testimonies have already been served on all parties of record.

Sincerely,

Marisa A. Sifontes

Marisa A. Sifontes
Assistant Consumer Advocate

Enclosures
cc: All parties of record w/o enclosure
Honorable John H. Corbett, Jr. w/o enclosure

69

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
v.	)	**Docket No. R-00974104**
Duquesne Light Company Application to approve restructuring plan pursuant to 66 Pa. C.S. § 2806(d)	)	

FIRST JOINT STIPULATION

Pursuant to an agreement of all parties to this case and as required by the Sixth Interim Order issued by the Presiding Judge on December 30, 1997, Duquesne Light Company ("Duquesne") and the intervenor parties hereby agree and stipulate to the following:

1. Each party to this Stipulation agrees that the testimony and exhibits itemized on the Stipulation Exhibits attached hereto shall be admitted into the record of this case.

2. Each party to this Stipulation agrees to waive its right to cross-examine the witnesses sponsoring the testimony and exhibits itemized on the Stipulation Exhibits attached hereto.

3. Each party to this Stipulation agrees to execute a copy of this Stipulation by causing counsel of record for each party (or the party itself if that party is unrepresented by counsel) to place its signature on the appropriate line below. Each party further agrees to file an executed version thereof with the Commission's Secretary and Prothonotary at the time it submits two copies of its testimony and exhibits to the Secretary and Prothonotary, as prescribed by the Sixth Interim Order.

Counsel for Duquesne Light: _____
John S. Moot

Counsel for Intervenor Party: _____
(Marisa A. Sifnites)

Name of Intervenor Party: Office of Consumer Advocate

Dated: January 7, 1998

FIRST JOINT STIPULATION
INDICES OF TESTIMONY & EXHIBITS

Exhibit No.	Description
1	City of Pittsburgh
2	Duquesne Industrial Intervenors (DII)
3	Enron Power Marketing, Inc. (ENRON)
4	Environmentalists (ENV)
5	Hospital Shared Services & Administrative Resources, Inc. (HSS/ARI)
6	International Brotherhood of Electrical Workers (IBEW)
7	Mid-Atlantic Power Supply Association (MAPSA)
8	New Energy Ventures (NEV)
9	Office of Business Advocate (OSBA)
10	Office of Consumer Advocate (OCA)
11	Office of Trial Staff (OTS)
12	Pennsylvania Retailers Association (PRA)

FIRST JOINT STIPULATION
EXHIBIT NO. 1

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
DUQUESNE LIGHT COMPANY

Application of Duquesne Light Company
for Approval of a Restructuring Plan
Under Section 2806 of the Public Utility Code
Docket No. R-00974104

CITY OF PITTSBURGH
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Brief Description
City Statement No. 1	Direct Testimony of Christopher D. Seiple (addressing issues pertaining to the Company's general overview/recovery plan and stranded costs).
City Exhibit No. 1	Resource Data International Background & History.
City Exhibit No. 2	RDI Market & Competitor Intelligence
City Exhibit No. 3 (incl. Tables 1-3)	Capacity Factor Analysis
City Exhibit No. 4	Delivered Output Analysis
City Exhibit No. 5	Early Plant Shutdown Savings Analysis
City of Pittsburgh, *et al.* Statement No. 2	Direct Testimony of Roger D. Colton (addressing issues pertaining to universal service, low income programs, energy conservation, consumer education, and phase-in).
Exhibit RDC-1	Resume of Roger D. Colton
Exhibit RDC-2	Summary of Colton electricity restructuring experience.
Exhibit RDC-3	Summary of Colton experience pertaining to design of low-income affordability programs.
Exhibit RDC-4	Number and Percent of LIHEAP Recipients by Income Range and Annual Electric Burdens.
Exhibit RDC-5	Recommendations pertaining to utility universal service programs which can help increase incomes of low-income consumers.
Exhibit RDC-6	Estimate of Universal Service Costs at 50 Percent CAP Participation.

Exhibit RDC-7	Summary of Universal Service Recommendations.
Exhibit RDC-8	Recommendations for Consumer Research section of an Education Plan
Exhibit RDC-9	Model 4-Phase Consumer Education Program
Exhibit RDC-10	Proposed Evaluation Process for Consumer Education Activities
Exhibit RDC-11	Summary of Consumer Education Recommendations
Exhibit RDC-12	Proposed Budget for Universal Service Programs

FIRST JOINT STIPULATION
EXHIBIT NO. 2

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 1	**Direct Testimony of Stephen J. Baron (Summary of Stranded Cost Analysis; Regulatory Policy Issues; Rate Design Issues)**		
Exhibit SJB-1	Expert Testimony Appearances		
Exhibit SJB-2	DII Summary of Recommended Stranded Costs		
Exhibit SJB-3	Example of DII Stranded Generation Sharing Analysis		
Exhibit SJB-4	DII Calculation of Adjusted Rate of Return		
Exhibit SJB-5	DII Summary of Estimated CTC Revenues by Rate Class		
Exhibit SJB-6	DII Load-weighted Market Prices		
Exhibit SJB-7	DII Unbundling Analysis for Rate RS		
Exhibit SJB-8	DII Unbundling Analysis for Rate L		
Exhibit SJB-9	DII Unbundling Analysis for Rate HVPS		

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 1R	**Rebuttal Testimony of Stephen J. Baron (Universal Service Cost Recovery Mechanism; Issues Regarding the Calculation of Market Prices and Stranded Cost; Response to OCA Regarding Unbundling Issues)**		
DII Statement No. 1S	**Surrebuttal Testimony of Stephen J. Baron (Responses to Company Witnesses Regarding Divestiture, Stranded Cost Sharing, CTC Calculation, and Rate Design Issues; Response to OSBA Witness Regarding CTC Calculation and Recovery)**		
DII Statement No. 2	**Direct Testimony of Randall J. Falkenberg (Calculation of Company Generation Stranded Cost; Analysis of Duquesne and ECAR Market Prices)**		
Exhibit RJF-1	Qualifications of Randall J. Falkenberg		
Exhibit RJF-2	Production Cost Model Studies and Benchmarks		
Exhibit RJF-3	Comparison of Market Price Model Results of K&A Model v. MAPS, IPM and PMDAM		
Exhibit RJF-4	DII Calculation of Company's Annual Revenue Requirements for Generation		
Exhibit RJF-5a	DII Total Generation Stranded Cost Calculation		
Exhibit RJF-5b	DII Calculation of Net Present Value of Contribution Margins		
Exhibit RJF-5c	DII Summary of Market Prices, Fuel Cost, Operating Margin and Generation by Plant		

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS
Page 3 of 4

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 2S	**Surrebuttal Testimony of Randall J. Falkenberg (Updated Calculation of Generation Stranded Costs; Responses to Company Witnesses Regarding Market Price Forecasts)**		
Exhibit RJF-6a	DII Updated Total Generation Stranded Cost Calculation		
Exhibit RJF-6b	DII Updated Calculation of Net Present Value of Contribution Margins		
Exhibit RJF-6c	DII Updated Summary of Market Prices, Fuel Cost, Operating Margin and Generation by Plant		
DII Statement No. 3	**Direct Testimony of Lane Kollen (Regulatory Assets; Transition Costs; Fossil Decommissioning; Nuclear Decommissioning; Securitization)**		
Exhibit LK-1	Resume of Lane Kollen		
Exhibit LK-2	Excerpts from Company Exhibits Illustrating Double Counting of FAS 109 Asset Related to Perry and Beaver Valley 1		
Exhibit LK-3	Excerpt from Company First Quarter 1997 SEC 10-Q Related to Deferred Coal		
Exhibit LK-4	Net Present Value of Deferred Rate Synchronization Costs at 12/31/98		
Exhibit LK-5	Duquesne Nuclear Decommissioning for Stranded Cost and Revenue Requirement (Beaver Valley 1, Beaver Valley 2, and Perry)		

DUQUESNE INDUSTRIAL INTERVENORS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
DII Statement No. 3S	**Surrebuttal Testimony of Lane Kollen (Responses to Company Witnesses Regarding Stranded Cost Methodology, Unamortized Debt Costs, Beaver Valley 2 Sale/Leaseback Refinancing Premium, Preaccrued Nuclear Outages, Deferred Employee Costs, Deferred Coal SFAS 106, Deferred Rate Synchronization Costs, Fossil Decommissioning, Securitization)**		
DII Cross Exh. 1	Response of Company Witness Hoffmann to Environmentalists' Interrogatories Set I, Number 23	12/18/97	12/18/97
DII Cross Exh. 2	Response of Company Witness Hoffmann to On-the-Record Data Request Concerning Customer Segment Contribution to Non-Coincident Peak Load		
DII Cross Exh. 3	Response of Company Witness Hoffmann to On-the-Record Data Request Concerning Mining, Construction, and Agriculture Customer Segments		

DUQUESNE LIGHT COMPANY

On-the-Record Data Requests

3. Provide a non-coincident peak calculation in form that is analogous to the coincident peak calculation provided in response to Data Request ENV-1-23.

Response:

Attached is a modified version of DLC's response to ENV-1-23 which list the non-coincidental peak load contribution for each customer group/segment associated with the proposed phase-in methodology.

Non-Coincidental Peak Load Contribution by Customer Class and Segment

Customer Class	Customer Group/Segment	Non-Coincidental Peak Contribution	Percentage Contribution to Non-Coincidental Peak
Residential	Group A - Accumulated Wealth	41	1.14%
	Group B - Mainstream Families	374	10.42%
	Group C - Mainstream Singles	273	7.60%
	Group D - Conservative Classics	49	1.36%
	Group E - Sustaining Families	49	1.36%
	Group F - Sustaining Singles	65	1.82%
	Group G - All Others	21	0.58%
	Subtotal Residential	**871**	**24.28%**
Commercial	Utility Services	155	4.33%
	Wholesale Trade	53	1.47%
	Retail Trade - Food	71	1.99%
	Retail Trade - Restaurants	85	2.36%
	Retail Trade - Merchandise	177	4.94%
	Office Buildings	399	11.13%
	Healthcare	142	3.95%
	Education	214	5.98%
	Services	283	7.89%
	Government	82	2.29%
	Small Business	324	9.04%
	Subtotal Commercial	**1,986**	**55.36%**
Industrial	Industrial - Chemical	68	1.88%
	Industrial - Plastic	14	0.39%
	Industrial - Glass	39	1.08%
	Industrial - Steel	449	12.52%
	Industrial - Other	161	4.48%
	Subtotal Industrial	**730**	**20.36%**
	TOTALS	**3,587**	**100.00%**

DUQUESNE LIGHT COMPANY

On-the-Record Data Requests

4. Provide breakdown of numbers for mining, construction and agriculture segments on FAH-4 in a manner comparable to that provided in response to ENV-1-23.

Response:

The market segments listed on FAH-4 as "Mining" and "Construction" are classified as "Industrial-Other" on the response to ENV-1-23. Similarly, "Agriculture" was classified within the "services" market segment.

FIRST JOINT STIPULATION
EXHIBIT NO. 3

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
DUQUESNE LIGHT COMPANY

Application for Approval of a Restructuring Plan
Pursuant to 66 Pa. C.S. § 2806(d)
Docket No. R-00974104

ENRON POWER MARKETING, INC.
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
Enron Cross Examination Exhibit No. 1	CFR Uniform System of Accounts: Accounts 908 and 909.	12/17/97	12/17/97
Enron Statement No. 1	**Direct Testimony of James D. Steffes** General overview of competitive services; the Portland General Code of Conduct.		
Exhibit 1 JDS-1	Market share of utilities/affiliates in Retail Access Programs.		
Exhibit 1 JDS-2	Portland General Electric Company Tariff Code of Conduct.		
Exhibit 1 JDS-3	Market share of affiliates in Retail Access Programs.		
Enron Statement No. 2	**Direct Testimony of Paul D. Reising** Rates for unbundled services of Transmission, Ancillary, Energy Delivery and Revenue cycles separately computed and stated.		
Exhibit 2 PDR-1	Educational and employment background of P.D. Reising.		
Exhibit 2 PDR-2	Definition and Description of Ancillary Services.		

Exhibit 2 PDR-3	Summary of Functional Costs.		
Exhibit 2 PDR-4	EPMI Proposed Class Rates		
Exhibit 2 PDR-5	EPMI Class Cost Summary		
Exhibit 2 PDR-6	pro forma Distribution Services Tariff		
Exhibit 2 PDR-7	Energy Delivery Rate Design		
Enron Statement No. 3	**Direct Testimony of Jeffrey A. Brown** Non-wire services, metering, meter-reading, billing and information services. "Open architecture" communication systems.		
Exhibit 3 JAB-1	Customer Account Services: Billing System Opportunities (representative example)		
Exhibit 3 JAB-2	Customer Account Services: Third Party Billing Services (representative example)		
Exhibit 3 JAB-3	Non-Wire Products and Services: "Endless Possibilities"		
Exhibit 3 JAB-4	Non-Wire Communications Network: Conceptual Model		
Exhibit 3 JAB-5	Metering and Billing Cycle		
Enron Statement No. 4	**Direct Testimony of Gayle Muench** Unbundling of billing and bill format; billing options ("Supplier Complete Bill Option"); phase-in of competition; customer selection and "slamming"; customer information ("Customer Education Program"); Duquesne's Universal Service Program in a competitive environment.		
Exhibit 4 GM-1	DQE Position on Competition		
Exhibit 4 GM-2	DQE Overview of Competition		
Enron Statement No. 5	**Direct Testimony of Lynn R. Coles** "Pro Forma Supplier Tariff." Access to point-to-point transmission service. EDC charges; minimum contract periods; planning reserves.		

Exhibit 5 LRC-1	Summary of educational background and general experience in electric utility industry.		
Exhibit 5 LRC-2	Proposed Electric Generation Supplier Tariff.		
Exhibit 5 LRC-3	GPU Market Line: Energy market prices; viability payments, all-in market line; market clearing prices.		
Enron Statement No. 1.1	**Surrebuttal Testimony of James D. Steffes** Response to Duquesne witnesses Hoffman and Allison.		
Enron Statement No. 2.1	**Surrebuttal Testimony of Paul D. Reising** Responses to rebuttal testimony of Duquesne witness Lahtinen; IBEW witness Moran; and OCA witness Alexander.		
Exhibit 2.1 PDR-8	Revised functional cost of service summary.		
Exhibit 2.1 PDR-9	Revised versions of class-based T & D charges (original Exhibit 2 PDR-4).		
Exhibit 2.1 PDR-10	Revised versions of voltage differentiated rates (original Exhibit 2 PDR-5).		
Enron Statement No. 3.1	**Surrebuttal Testimony of Jeffrey A. Brown** Responses to Duquesne witness Allison; and IBEW witnesses Schmidt and Moran.		
Enron Statement No. 4.1	**Surrebuttal Testimony of Gayle Muench** Responses to Duquesne witnesses Allison, Hoffman and Flynn; OCA witness Alexander; and IBEW witness Moran.		
Enron Statement No. 5.1	**Surrebuttal Testimony of Lynn R. Coles** Responses to rebuttal testimony of IBEW witness Moran; and witnesses Irvin and Karl.		

FIRST JOINT STIPULATION
EXHIBIT NO. 4

Roger E. Clark, Esq.

Attorney for The Environmentalists

905 Denston Drive
Ambler, PA 19002-3901
phone: 215.643.2364
fax: 215.628.2630
e-mail: rclark@libertynet.org

January 7, 1998

John Moot
Skadden, Arps, Slate, Meagher & Flom LLP
1440 New York Avenue, N.W.
Washington, D.C. 20005-2111

Re: Duquesne Light Company Application for Approval of a Restructuring Plan, Docket No. R-0097104.

Dear Mr. Moot:

Thank you for catching our oversight regarding Roger Colton's surrebuttal testimony. In accordance with the Sixth Interim Order issued by Judge Corbett on December 30, 1997, I am sending you the following updated index of the Environmentalists' testimony and exhibits in the above-referenced proceeding:

Exhibit	Description	Date Identified	Date Admitted
Environmentalists' Statement No. 1	Direct Testimony of David Schoengold		
Ex. DS-1	Resume of David Schoengold		
Ex. DS-2	*Environmentalists' Vision for the New Electricity Marketplace*		
Ex. DS-3	Return on the Investment to Date for Stockholders		
Ex. DS-4	Total Return to Date for Stockholders		
Ex. DS-5	Methodology for Determining Total Return Of and On Investment for Stockholders Through End of Transition Period		
Ex. DS-6	Proposed Draft for Net Billing Tariff		

Environmentalists' Index of Testimony and Exhibits
January 7, 1998
Page 2

Environmentalists' Statement No. 1-S	Surrebuttal Testimony of David Schoengold		
Environmentalists' Statement No. 2	Direct Testimony of Bruce Biewald		
Ex. BEB-1	Resume of Bruce Biewald		
Ex. BEB-2	Graph of TLG Decommissioning Estimates: 1977-1995		
Ex. BEB-3	*Full Environmental Disclosure for Electricity: Tracking and Reporting Key Information*, March 1997		
Ex. BEB-4	Better Choice Plan - Three Examples		
Environmentalists' Statement 2-S	Surrebuttal Testimony of Bruce Biewald		
Ex. BEB-5	Economic Analysis of Duquesne Light Company's Perry 1 Investment		
Ex. BEB-6	Economic Analysis of Duquesne Light Company's Beaver Valley 2 Investment		
Ex. BEB-7	Assumptions for Economic Analysis for Perry 1 and Beaver Valley 2		
City of Pittsburgh *et al.* Statement No. 2 (cosponsored with the Environmentalists)	Direct Testimony of Roger Colton		
Ex. RDC-1	Resume of Roger Colton		
Ex. RDC-2	Summary of Roger Colton's Restructuring Work		
Ex. RDC-3	Summary of Roger Colton's Energy Efficiency Work		
Ex. RDC-4	Number and Percentage of LIHEAP Recipients by Income Range		

Ex. RDC-5	Summary of the BOSS and Earned Income Tax Credit Outreach		
Ex. RDC-6	Estimate of Universal Service Program Costs		
Ex. RDC-7	Summary of Universal Service Recommendations		
Ex. RDC-8	Summary of Consumer Research Section of Consumer Education Plan		
Ex. RDC-9	Four Phase Consumer Education Program		
Ex. RDC-10	Consumer Education Evaluation Process		
Ex. RDC-11	Summary of Consumer Education Recommendations		
Ex. RDC-12	Proposed Universal Service Budget		
City of Pittsburgh *et al.* Statement No. 3-S (cosponsored with the Environmentalists)	Surrebuttal Testimony of Roger Colton		
Ex. RDC-1-S	Memorandum of Residential Mobility and the Low Income Consumer		
Ex. RDC-2-S	Prepayment Meters and Low Income Consumers		

I have also sent this document to you by e-mail at "jmoot@skadden.com". Copies of this letter are being served on all parties of record by facsimile.

Sincerely,

Roger E. Clark

Roger E. Clark
Attorney for the Environmentalists

Copies: All parties of record

FIRST JOINT STIPULATION
EXHIBIT NO. 5

HSS AND ARI
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	Description	Date Identified	Date Admitted
	Prepared Direct Testimony of Dr. Robert B. Weisenmiller, Volume I		
RBW-1	Supplemental Response to Item Nos. HSS-1-001, 21 (Supp.), etc. (corrections to Duquesne's case-in-chief)		
RBW-2	Skadden, Arps letter forwarding narrative prepared by Northbridge Group regarding discovery requests HSS-3-008 and HSS-3-009		
RBW-3	"Generating Assets," April 1995 (Duquesne study re: possible sales of its generating assets)		
RBW-4	Chart, "Best Practices Reduce Total Personnel By 45%"		
RBW-5	Duquesne Fossil Generating Business Unit, Development of a GENCO, Dec. 1996		
RBW-6	Presentation to Project Lead Team - Project Update, July 15, 1996		
RBW-7	Presentation to Project Lead Team - Preliminary Valuation and Operating Cost Allocation, August 5, 1996		
RBW-8	Presentation to Project Lead Team - Asset Valuation and Strategic Options, August 16, 1996		
RBW-9	Presentation to Project Lead Team - Regulatory Recommendations and GENCO Structure, Sept. 13, 1996		
RBW-10	CS First Boston, Materials Prepared for Discussion, Nov. 21, 1996		
RBW-11	Charts, "Generating Costs For Duquesne"		
RBW-12	Table, To Go Cost of Generation, etc.		
RBW-13	Chart, Duquesne System Lambda, 1996		
RBW-14	Duquesne Response to Interrogatory No. HSS-1-72/73 (revised) and attachments (re: RFP bids, etc.)		
RBW-15	Duquesne letter regarding RFPs and bid forms		

Exhibit	Description	Date Identified	Date Admitted
RBW-16	Duquesne Response to Interrogatory No. HSS-1-016 (revised) (Testimony of D.W. Marshall, Investigation into Electric Power Competition, I-940032, filed Nov. 6, 1995)		
RBW-17	West Penn Power Docket No. R-00973981 Interrogatories (AYP Energy, Inc.'s RFP bids)		
RBW-18	Duquesne Response to Interrogatory No. OCA-3-016 (current ECR charge is 12.822 mill/kWh)		
RBW-19	Duquesne Response to Interrogatory No. HSS-1-026		
RBW-20	Excerpts from Alexander Galatic, Written Rebuttal Testimony on Behalf of West Penn Power Company		
RBW-21	Duquesne's Response to HSS-1-015 (revised) – **Protected Materials**		
RBW-22	Duquesne's Response to HSS-1-015 (revised) – **Protected Materials**		
RBW-23	Duquesne Response to Interrogatory No. OCA-3-001 (credit rating reports)		
RBW-24	Table, Utility Comparison		
RBW-25	Chart, Ranking of DLCo & APS Coal Plants with PJM Coal Plants, Based on Total Expenditures per Net MWh - 1995		
RBW-26	A Report on The Review of Potential Stranded Costs, Duquesne Light Company, August 1997		
RBW-27	Duquesne Response to Interrogatory No. DH-1-28 (settlement agreement between GE and *inter alia*, Duquesne)		
RBW-28	Executive Summary, Duquesne Light Company (1996 rating agency presentation)		
RBW-29	Tables, DQE 12-month Results; Continued Earnings and Dividend Growth; Consistent Financial Performance – NatWest Securities Mid-Atlantic/New England Utility Seminar, Sept. 23, 1997		
RBW-30	Duquesne Financial, Sales and Operating Information (1996 rating agency presentation)		
RBW-31	Duquesne Rating Agency Presentation, August 1996		

Exhibit	Description	Date Identified	Date Admitted
RBW-32	Duquesne Response to Interrogatory Nos. HSS-3-01 and HSS-3-02 (explanation of ratepayer benefits)		
RBW-33	Duquesne Response to Interrogatory No. OCA-1-007 (regulatory assets and decommissioning expenses)		
RBW-34	Duquesne Response to Interrogatory No. HSS-1-044 (regulatory assets in rate base)		
RBW-35	Duquesne Response to Interrogatory No. HSS-1-043 (Supp.) (authorization for claimed regulatory assets: excerpts from 860378 order)		
RBW-36	Duquesne Response to Interrogatory No. HSS-1-043 (Supp.) (authorization for claimed regulatory assets: excerpts from R-870222 order)		
RBW-37	Duquesne Response to Interrogatory of David Hughes Set I, Item No. DH-1-10 (excerpts from Duquesne's 1995 and 1995 Form 10-Ks)		
RBW-38	Duquesne Response to Interrogatory No. HSS-1-030 (revised) (excerpts from Pt. Martin amended proposal re: deferred costs)		
RBW-39	Excerpts from Duquesne 1996 Form 10-K		
RBW-40	Excerpts from Duquesne Response to Interrogatory No. DH-1-18 (Feb. 17, 1983 letter to Duquesne Shareholders)		
RBW-41	Duquesne Response to Interrogatory No DH-1-10 (excerpts from Duquesne's 1995 and 1995 Form 10-Ks)		
RBW-42	Duquesne Response to Interrogatory No. OCA-1-040 (Brunot Island rate base treatment)		
RBW-43	Duquesne Response to Interrogatory No. OCA-3-042 (Brunot Island and Phillips units—no plans to return cold service units to service)		
RBW-44	Duquesne Response to Interrogatory No. ENV-1-024 (excerpts from Sept. 1997 Integrated Resource Plan)		
RBW-45	Duquesne Response to Interrogatory No. HSS-3-03 (excerpts from Pennsylvania PUC Order in P-900485)		
RBW-46	Duquesne Response to Interrogatory No. OCA-1-018 (future use or sale of Brunot Island and Phillips units)		

Exhibit	Description	Date Identified	Date Admitted
RBW-47	Duquesne Response to Interrogatory No. OCA-1-008 (Chart, Annual Amortization Amounts)		
RBW-48	Table, All-In Costs of Combined Cycle Plants		
RBW-49	Duquesne Response to Interrogatory No. HSS-1-091 (Schnitzer's natural gas market price forecasts)		
RBW-50	Tables, Wellhead (lower 48) Natural Gas Price Projections (1995)		
RBW-51	Duquesne Response to Interrogatory No. HSS-2-38 (gas transportation costs forecast)		
RBW-52	Duquesne Response to Interrogatory No. HSS-2-34 (2.5% inflation factor sources)		
RBW-53	Table, Percent Change from Previous Period--GDP PPD		
RBW-54	Excerpts from Duquesne Resource Planning Report, July 1, 1996		
RBW-55	Presentation to Project Lead Team - Preliminary Recommendations, August 30, 1996		
RBW-56	Presentation to DQE, Inc. Regarding the Sale of Certain Generating Assets, June 16, 1995		
RBW-57	Table, Comparison of Estimates of Market-Clearing Prices		
	Prepared Surrebuttal Testimony of Dr. Robert B. Weisenmiller, Volume IV		
RBW-58	Presentation to Gary Brandenberger - Draft Presentation for Fall Planning Council, Sept. 5, 1996 (Metzler)		
RBW-59	Presentation to Gary Brandenberger - Draft Presentation for Fall Planning Council, Sept. 5, 1996 (Metzler)		
RBW-60	Petition of Duquesne to discontinue normal operation of Phillips Power Station, South Heights, Pennsylvania		
RBW-61	Calpine Acquires 120 MW Gas-Fired Facility, Non-Nuclear Electric Power Generation, etc.		

Exhibit	Description	Date Identified	Date Admitted
RBW-62	Errata to Prepared Testimony of Dr. Robert B. Weisenmiller		

RBW-62

ERRATA

The following corrections should be made to the testimony of Dr. Robert B. Weisenmiller:

(a) Prepared Direct Testimony:

1. At page 41, line 12, after "effect." insert "See Exh. RBW-18."

2. At page 118, line 16, change "West Penn's" to read "Duquesne's".

3. At page 123, line 5, change "EIA, Penelec, PECO, AYP" to read "EIA, Penelec, AYP".

(b) Prepared Surrebuttal Testimony:

1. At page 1, add the following entities to the list of HSS and ARI members sponsoring Dr. Weisenmiller's testimony:

South Hills Health System (all locations)
University of Pittsburgh Medical Center (all locations)

FIRST JOINT STIPULATION
EXHIBIT NO. 6

SYSTEM COUNCIL U-10, INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	*Description*	*Date Identified*	*Date Admitted*
IBEW Statement No. 1	**Rebuttal Testimony of Timothy Moran (Generation suppliers should not be allowed to provide metering, billing, and other customer service functions. Duquesne should not be required to sell or shut down any of its power plants.)**		
Schedule TM-1	Rebuttal testimony of William Schmitt from the PP&L Restructuring Case		
Schedule TM-2	Number of Duquesne Light Company employees by year from 1986-1996 (HSS-2-017)		
Schedule TM-3	Duquesne Light Company Distribution of Salaries and Wages for 1996 (FERC Form 1, pages 354-355)		

FIRST JOINT STIPULATION
EXHIBIT NO. 7

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
DUQUESNE LIGHT COMPANY

Application for Approval of a Restructuring Plan
Pursuant to 66 Pa. C.S. §2806(d)
Docket No. R-00974104

INDEX OF MAPSA TESTIMONY AND EXHIBITS

Exhibit	*Description*	*Date Identified*	*Date Admitted*
MAPSA Statement No. 1	Direct Testimony of Whitfield A. Russell (Addressing competitive issues raised by Duquesne's Customer Choice Plan)		
Exhibit WAR-1	Whitfield A. Russell Curriculum Vitae		
Exhibit WAR-2	Chart Showing Monthly Firm Available Transmission Capacity for Allegheny Power		
Exhibit WAR-3	1996 Duquesne System Lambda		
Exhibit WAR-4	Calculation of Duquesne CGC Based Upon 1999 CCGT [1]		
Exhibit WAR-5	ERRATA to Prepared Direct Testimony of Whitfield A. Russell		
MAPSA Statement No.1-SR	Prepared Surrebuttal Testimony of Whitfield A. Russell		

FIRST JOINT STIPULATION
EXHIBIT NO. 8

INDEX OF TESTIMONY AND EXHIBITS
OF INTERVENOR NEV EAST, L.L.C.,
SUBMITTED PURSUANT TO SIXTH INTERIM ORDER

Statement/Exhibit	*Description*
NEV Statement No. 1	Direct Testimony of David Magnus Boonin (regarding the unbundled rate for generation, CTC methodology, unbundling of all tariffs, and billing and metering issues)
Exhibit NEV/DMB #1	Resume of David Magnus Boonin
Exhibit NEV/DMB #2	Chart setting forth methodology for reconciling the CTC
NEV Statement No. 2	Direct Testimony of Nancy I. Day (regarding the importance of unbundling distribution services to the formation of a competitive energy market)
Exhibit NEV/NID #1	Resume of Nancy I. Day

*Pursuant to the December 30, 1997 Order of Administrative Law Judge John H. Corbett, Jr. and agreement of the parties, the foregoing testimony will be admitted into the record by stipulation and without cross-examination.

FIRST JOINT STIPULATION
EXHIBIT NO. 9

OFFICE OF SMALL BUSINESS ADVOCATE
INDEX OF TESTIMONY AND EXHIBITS

Statement/Exhibit	Description
OSBA Statement No. 1*	Direct testimony and Exhibit of Brian Kalcic (recommending adjustments in Duquesne's distribution-related revenue requirements and its rate redesign plan, and offering comments on Duquesne's proposed Phase-In plan.)
OSBA Exhibit No. 1* (with Schedules BK-1, BK-2 and BK-3)	Schedules summarizing Duquesne's functionalized revenue requirements including OSBA's proposed adjustments
OSBA Statement No. 1R**	Rebuttal Testimony and Exhibit of Brian Kalcic (addressing issues raised by other witnesses regarding the pace of stranded cost recovery, the determination of CTC, allocation of universal service costs and proposals for phase-in)
OSBA Exhibit No. 1R** (Schedule BK-1R)	Amortization of DII recommended stranded costs over 4 versus 7 years
OSBA Statement No. 1S***	Surrebuttal Testimony of Brian Kalcic (responding to Co. witness Lahtinen regarding use of realized rather than claimed rate of return for unbundling rates and DII witness Baron regarding allocation of CTC revenue responsibility to all classes)

* Served November 7, 1997
** Served December 2, 1997
*** Served December 11, 1997

FIRST JOINT STIPULATION
EXHIBIT NO. 10

OFFICE OF CONSUMER ADVOCATE
INDEX OF TESTIMONY AND EXHIBITS

Exhibit	*Description*	*Date Identified*	*Date Admitted*
OCA Statement No. 1	Direct Testimony of Matthew I. Kahal (Evaluation of Duquesne's proposed stranded cost plan)		
Schedule MIK-1	OCA Overall Stranded Cost Summary		
Schedule MIK-2	Excess Pre-Tax Earnings During Transition Period		
Schedule MIK-3	Retail Rate Comparisons for 1996		
Schedule MIK-4	DRI vs. Duquesne Inflation Rate Forecasts		
Schedule MIK-5	Derivation of the Discount Rate		
Schedule MIK-6	Productivity Enhancement Savings		
Schedule MIK-7	PECO and West Penn Power Life-Extension Costs for Coal Plants		
Schedule MIK-8	Cheswick Life Extension Costs and Net Benefits		
Schedule MIK-9	Generation Net Merger		
OCA Statement No. 1S	Surrebuttal Testimony of Matthew I. Kahal (Response to Rebuttal Testimony on stranded cost issues)		
Schedule MIK-1 UPDATE	OCA Overall Stranded Cost Summary		
Schedule MIK-6 UPDATE	Productivity Enhancement Savings		
Schedule MIK-10	Projected Pre-Tax Operating Losses During Transition		
OCA Statement No. 2	Direct Testimony of Douglas C. Smith (Market Price Analysis)		
Exhibit DCS-1	Resume of Douglas C. Smith		
Exhibit DCS-2A	New Combined Cycle Non-Fuel Cost Assumptions		

Exhibit DCS-2R	New Combustion Turbine Non-Fuel Cost Assumptions		
Exhibit DCS-3	Spring 1997 DRI Fuel Price Escalation Rates		
Exhibit DCS-4	APS-DQL Market Price Estimate		
Exhibit DCS-5	DQL Weighted Generation Price		
OCA Statement No. 2S	Surrebuttal Testimony of Douglas C. Smith (Response to rebuttal testimony on market price issues)		
OCA Statement No. 3	Direct Testimony of Thomas S. Catlin (Regulatory asset issues, nuclear and fossil decommissioning, taxes and other transition costs)		
Schedule TSC-1	Summary of Regulatory Assets and Other Transition Expenses		
Schedule TSC-2	Summary of Decommissioning Funding Requirements as of 12/31/98		
OCA Statement No. 3S	Surrebuttal Testimony of Thomas S. Catlin (Response to rebuttal testimony on prescribed nuclear outage costs and unamortized debt costs)		
OCA Statement No. 4	Direct Testimony of Lee Smith (Rate design, unbundling, cost allocation, and CTC design)		
Exhibit LS-1	Summary of Qualifications and Experience		
Exhibit LS-2	Calculation of Market Price		
Exhibit LS-3	1996 Administrative & General Expenses		
Exhibit LS-4	Retail Cost of Service CTC Proposal		
Exhibit LS-5	Retail CTC/Calculation of Levelized CTC		
Exhibit LS-6	Unbundled Rate Design Residential - Rate RS		
OCA Statement No. 4S	Surrebuttal Testimony of Lee Smith (Response to testimony on treatment of ancillary service costs, line losses, A&G adder, and rates of return)		
Exhibit LS-7	Revised LS-4 (Retail Cost of Service)		

Exhibit LS-8	Revised LS-2 (Calculation of Market Price)		
Exhibit LS-9	Revised LS-5 (Retail CTC)		
Exhibit LS-10	Revised LS-6 (Unbundled Rate Design)		
OCA Statement No. 5	Direct Testimony of Barbara Alexander (Consumer education and consumer protection issues)		
Exhibit BA-1	Resume of Barbara Alexander		
Exhibit BA-2	Vermont Consumer Information and Education Plan		
Exhibit BA-3	California Statewide Consumer Education Plan		
Exhibit BA-4	Massachusetts Department of Public Utilities Code of Conduct		
OCA Statement No. 5R	Rebuttal Testimony of Barbara Alexander (Response to testimony on provision of generation services to default customers and supplier-only bill option)		
OCA Statement No. 5S	Surrebuttal Testimony of Barbara Alexander		
Exhibit BA-S-1	Executive Summary of New Hampshire Pilot Program Survey Report		
Exhibit BA-S-2	CAPUC Fact Sheets on Consumer Education Plan		
Exhibit BA-S-3	Recommendations of the Maine Consumer Education Advisory Board		
OCA Statement No. 6	Direct Testimony of Nancy Brockway (Universal Service Issues)		
Exhibit NB-Duq-1	Resume and Curriculum Vitae of Nancy Brockway		
Exhibit NB-Duq-2	Duquesne Estimation of Potential CAP Eligible Customers		
Exhibit NB-Duq-3	Universal Service Costs - Per kWh Allocator		
Exhibit NB-Duq-4	Development of Non-Production Revenue Allocator		

OCA Statement No. 65	**Surrebuttal Testimony of Nancy Brockway (Universal Service Issues)**		

FIRST JOINT STIPULATION
EXHIBIT NO. 11

Pennsylvania Public Utility Commission
v.
Duquesne Light Company

Docket No. R-00974104

Index* of OTS Testimony And Exhibits Not Yet Admitted

Exhibit	Description	Date Identified	Date Admitted
OTS Statement No. 3	Direct Testimony of Paul M. Yarolin (concerning Universal Service and rate unbundling)		
OTS Cross Examination Exhibit No. 3	On-the-Record Data Request Response (O'Brien Number 1) concerning the difference in balances associated with cold reserve units		
OTS Cross Examination Exhibit No. 4	On-the-Record Data Request Response (O'Brien Number 4) concerning recovery of decommissioning costs		
OTS Cross Examination Exhibit No. 5	On-the-Record Data Request Response (O'Brien Number 5)** concerning recovery of decommissioning costs		

* OTS reserves the right to request admission of additional exhibits upon receipt of all responses to On-the-Record Data Requests.

** OTS has requested that this On-the-Record Data Request Response be supplemented to properly respond to the request.

FIRST JOINT STIPULATION
EXHIBIT NO. 12

PENNSYLVANIA RETAILERS ASSOCIATION
INDEX OF TESTIMONY

EXHIBIT	DESCRIPTION	DATE IDENTIFIED	DATE ADMITTED
PRA Statement No. 1	Direct Testimony of Chris K. Albrecht (Phase-in Procedure for retail competition)		

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00974104**
	)	
Duquesne Light Company Application for Approval of a Restructuring Plan Pursuant to 66 Pa. C.S. § 2806(d)	)	

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing document, by facsimile, upon the participants on the attached service list in accordance with Section 1.54 of the Commission's regulations.

Dated this 7th day of January, 1998.

/s/

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OCA Statement No. 1

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

NOVEMBER 1997

EXETER
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TABLE OF CONTENTS

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

DIRECT TESTIMONY OF MATTHEW I. KAHAL

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. My business address is 12510 Prosperity Drive, Silver Spring, Maryland 20904.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration include industrial organization, economic development and econometrics.

Q. PLEASE STATE YOUR PRESENT POSITION.

A. I am a Senior Economist and Principal at Exeter Associates, Inc., a consulting firm specializing in public utility regulation and energy studies. I have held that position since January 1981.

Q. PLEASE DESCRIBE YOUR PAST EMPLOYMENT.

A. Prior to joining Exeter Associates, I served on the Economic Evaluation Directorate of the Aerospace Corporation, a federally-funded research and development center. At Aerospace, I conducted studies for the U.S. Department of Energy's Strategic Petroleum

Reserve. From 1977 to 1980, I was employed with a Washington, D.C. consulting firm as a staff economist conducting technical studies on topics concerning the electric utility industry.

Before entering consulting, I served on the Economics Department faculties of the University of Maryland and Montgomery College teaching courses on economic principles, development and business.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES WITH EXETER ASSOCIATES?

A. Since the early 1980s, I have directed Exeter's extensive work for the Maryland Department of Natural Resources (DNR). Our firm has been serving as DNR's integrator for economic studies, and as the Program Manager, I have chief responsibility for the technical studies performed by Exeter and other contractors. Study areas currently include or have included long-range load forecasting, power supply planning, plant licensing, cogeneration/small power production, demand-side management and Clean Air Act compliance. Much of my recent work has focused on electric utility competitive restructuring and utility mergers.

My other main area of responsibility with Exeter concerns rate of return and utility financial issues. I have conducted a number of rate of return and other financial studies relating to electric, water, gas and telephone utilities, and I have testified on this subject area on more than 100 occasions within the past 15 years.

Appendix A accompanying my testimony provides a more detailed listing of my qualifications, including past cases in which I have testified.

Q. DO YOU BELONG TO ANY PROFESSIONAL ORGANIZATIONS?

A. I am a member of the American Economic Association, the American Finance Association and the International Association for Energy Economics.

Q. ARE YOU PRESENTLY INVOLVED IN ELECTRIC UTILITY RESTRUCTURING EFFORTS IN OTHER STATES?

A. Yes. Restructuring and mergers have occupied most of my professional work over the past two years. In addition to my work in Pennsylvania, I am presently participating in formal restructuring cases in Louisiana, Montana and New Jersey, with my primary assignment being the quantification of stranded cost. I also have assisted the Rhode Island PUC with evaluations of generation divestiture plans, and I have been an advisor to the Maryland State agencies on that state's generic investigation of competitive restructuring.

II. INTRODUCTION AND SUMMARY

Background on the Stranded Cost Issue

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Exeter Associates, Inc. has been retained by the Office of Consumer Advocate (OCA) to address the stranded cost aspects of Duquesne Light Company's (the Company or DLC) restructuring filing. My assignment in this case is to present the overall quantification of DLC's stranded costs and to evaluate the Company's proposed stranded cost plan. My analysis incorporates the findings of OCA witness Catlin on regulatory assets and "transition expenses" and OCA witness Douglas Smith's projections of market revenue and fuel expenses.

Q. WHAT DOES THE TERM "STRANDED COST" MEAN TO AN ELECTRIC UTILITY RATE ANALYST?

A. The term stranded cost refers to those costs which would be recoverable from utility customers under traditional regulation but which the utility will not be able to recover under a competitive industry structure. What gives rise to stranded costs is the expectation that once competition in generation is introduced, competitive forces and efficiencies will lead to market prices which will be lower than the utility's per unit full embedded costs (computed using traditional regulatory principles). Of course, it is also possible that market prices could exceed regulated rates in which case stranded costs would be negative.

There are three concepts regarding stranded costs which must be kept in mind at the present time. First, stranded cost relates only to the power supply (i.e., generation plus purchased power) portion of an electric utility's business since the other functional areas will remain regulated, not subject to direct competition (at least for now). Second, policy makers and regulators normally recognize only those stranded costs net of reasonable

mitigation efforts, i.e., new efficiencies and other feasible measures which could reduce embedded costs and/or enhance asset value. Third, stranded costs must be evaluated on a "net" basis, i.e., the above market and below market value assets should be permitted to offset.

Q. PLEASE DESCRIBE THE CRITERIA UNDER PENNSYLVANIA'S RESTRUCTURING ACT FOR RECOVERY OF STRANDED COST.

A. In addition to the concepts discussed above, it is essential that the assets to be recovered would have been reasonably recoverable under traditional regulation. In addition, these costs, under the statute, must be known and measurable, presented on a net present value basis, and fit within the definition of stranded cost provided by the statute.

The statutory definition sets forth three general categories of stranded cost recovery. The first category consists of regulatory assets, deferred charges, unfunded portions of projected nuclear decommissioning costs, and the cost obligations with non-utility generating projects that have received a Commission order. For this category of costs, recovery is pursuant to Section 2808(c)(1) which provides that the Commission shall allow recovery of such costs once it is determined that they have met the requirements of the definition.

The second category of costs includes the prudently incurred costs related to the buyout, buydown, cancellation, or renegotiation of non-utility generation contracts. The recovery of costs in this category is governed by Section 2808(c)(2) which provides that the Commission shall allow recovery of such costs once it is determined that they have met the requirements of the statute.

The third category of costs are those associated with a utility's own generating assets, recovery of which is under Section 2808(c)(3). For a utility's own generating assets, the statute requires that any recovery from ratepayers be just and reasonable under

the terms of the statute. Even if a utility's own prudently incurred generating asset costs are found to be stranded, it still must be demonstrated that recovery from ratepayers of any or all of these costs is just and reasonable.

The generation-related assets being sought for recovery should be truly stranded (on a net non-mitigable basis) after the introduction of retail competition, and under the most reasonable future scenario. If, under the most reasonable future assumptions, the assets in question are able to earn sufficient returns in a competitive environment, there would be no reason to provide special stranded cost recovery.

Duquesne vs. OCA Results

Q. GIVEN THESE STANDARDS AND CRITERIA FOR STRANDED COST RECOVERY, WHAT IS DUQUESNE'S ESTIMATE OF STRANDED COST?

A. Pennsylvania's statute specifies a seven-year transition period for recovery of the utility's stranded cost as of January 1, 1999, the beginning of the customer choice phase-in. Duquesne's filing provides no analysis or estimate of its total stranded costs as of the beginning of the transition period. Rather, the Company provides what it considers to be a provisional estimate of its stranded costs as of the end of the transition period at December 31, 2005. I refer to this as a "provisional estimate" because the Company seeks the opportunity to revisit stranded cost (or market valuation) in 2003 and obtain a final determination at that time.

Based on its updated analysis supplied to the parties in late October, Duquesne estimates that its stranded costs as of December 31, 2005 will be in a range of a negative $233 to a positive $423 million, depending on the post-2005 market price outlook. Moreover, these results are prior to considering the cost savings effects of its proposed merger with Allegheny Power. The Company commits to a further accelerated depreciation of $160 million during the transition period if the merger is completed.

Recognizing this change, the Company's 12/31/2005 stranded costs would be in a range of a negative $393 million to a positive $263 million.

Q. HAVE YOU ESTIMATED DUQUESNE'S STRANDED COSTS AT DECEMBER 31, 2005?

A. No. The purpose of this proceeding is to establish an implementation plan for competition in generation, including the determination of the competitive transition charges (CTCs) to provide the appropriate recovery of stranded cost. This requires a determination of stranded costs as of January 1, 1999 -- not as of 2006. This has been the approach followed by every other electric utility in Pennsylvania and all parties addressing the stranded cost issue.

Instead, my testimony presents the OCA's overall estimate of Duquesne's stranded cost as of the beginning of the transition period. The overall estimate includes the findings of OCA witness Thomas S. Catlin (OCA Statement No. 3) on regulatory assets and certain other items. My testimony analyzes the stranded costs directly related to owned-generation assets. In doing so, I incorporate the fuel costs, non-fuel variable O&M and market revenue for Duquesne's units projected by OCA witness Mr. Douglas Smith.

Q. WHAT ARE YOUR STRANDED COST RESULTS AS OF 12/31/98?

A. Combining owned-generation, regulatory assets and other transition costs, Duquesne's stranded costs at 12/31/98 are $1,566.6 million on a net present value basis. If merger savings (net of costs to achieve) are recognized, the total declines to $1,414.3.[1] The (pre-merger) total breaks down as $1,140.3 million for owned-generation, $408.07 million for other regulatory assets and $18.20 million for other transition costs. This breakdown

[1]Although my testimony identifies the expected generation-related merger savings, this should not be interpreted as OCA support for PaPUC merger approval. The OCA is scheduled to file its direct testimony in the merger docket on November 14, 1997.

classifies the Beaver Valley 2 lease ($513 million) as a component of owned-generation rather than as a regulatory asset. It should be noted that 0.1 percent of stranded costs identified above are allocable to the FERC jurisdiction.

My overall stranded cost summary is shown on Schedule MIK-1, page 1 of 3. Pages 2 and 3 of that schedule provide the supporting information specifically relating to owned-generation stranded costs.

Q. YOUR STRANDED COST ESTIMATE OF $1.4 TO $1.6 BILLION IS QUITE LARGE. WHY IS THAT?

A. It is attributable almost entirely to DLC's three jointly-owned nuclear units, Beaver Valley 1, Beaver Valley 2 and Perry. Inclusive of the Beaver Valley 2 lease and incremental nuclear decommissioning funding needs, the book cost of these plants is in excess of $1 billion. Unfortunately, these plants are so costly to operate on an ongoing basis, they can be expected to provide only modest net revenue over their remaining lives to offset the enormous net book values of the units. By comparison , with the exception of one plant, Duquesne's coal-fired units appear to be economic and have little or no stranded costs.

Q. YOU STATED THAT DUQUESNE HAS NOT PRESENTED A STRANDED COST ANALYSIS FOR THE TRANSITION PERIOD. HOW THEN DOES IT PROPOSE TO ESTABLISH TRANSITION CHARGES TO RECOVER ITS STRANDED COSTS?

A. The plan for recovery of stranded costs is described by Duquesne witnesses Marshall and Clayton and includes the following elements.

Duquesne seeks to retain its capped rates in place over the entire seven-year transition period. During that time period, the Company will reduce its stranded costs through accelerated depreciation and amortization of both its owned-generation plant and

its regulatory assets. The minimum depreciation/amortization commitment over this time period is in excess of $1.7 billion (or about $1.9 billion with the merger). Further accelerations may occur through the so-called ROE spillover, i.e., if Duquesne's earnings exceed 12.0 percent.

During the transition period, the CTC charges would be established annually based on the difference between the frozen generation rate and the actual market price. The actual market price itself would be determined by an auction of a block of power to be conducted annually by Duquesne.

Duquesne intends to initiate a "final" determination of its stranded costs in the year 2003. A three-member arbitration panel would be convened to produce a market valuation of Duquesne's generation units. If they find that market value of the units equals or exceeds net book value at that time, then the CTCs can be terminated prior to the end of the seven-year period. However, if the panel finds that stranded costs are likely to exist at 12/31/2005, Duquesne intends to continue the CTC after that date to recover remaining stranded cost.[2] As a consumer protection, if market prices increase above a certain level, the final valuation could be accelerated to an earlier date (e.g., 2001 or 2002). If the Commission rejects the findings of the arbitration panel and adopts a finding adverse to Duquesne, the Company reserves the right to divest its assets.

Q. UNDER THE COMPANY'S PROPOSAL, WILL OVERALL RATES REMAIN CAPPED AT CURRENT LEVELS?

A. No. Although Duquesne is proposing a rate cap, rates would be capped subsequent to a rate increase of 1.9 mills per kWh (about 2 percent overall). This increase is being proposed in order to reflect the ECR ceiling amount of 14.7 mills per kWh specified in

[2]As Mr. Marshall explains, "the valuation will be the basis for any further relief that Duquesne is entitled to seek under the restructuring legislation." (pages 15-16)

the 1996 Ft. Martin settlement. Duquesne's current rates reflect a lower ECR level of 12.8 mills per kWh.

Q. HOW DOES THE "ROE SPILLOVER" WORK?

A. If during the transition period, Duquesne's earnings exceed 12.0 percent (its 11.5 percent claimed cost of equity plus 50 basis points), the excess earnings would be transferred to a fund earmarked to offset stranded costs, i.e., through accelerated depreciation. If earnings are less than 11.0 percent, then amounts can be withdrawn from the fund, to the extent available, to increase Duquesne's earnings. Company testimony does not provide a description of the administrative and regulatory procedures for determining the Company's earnings levels.

Q. GIVEN DUQUESNE'S INTENTION TO ESTABLISH THE RESIDUAL STRANDED COST IN 2003, WHAT IS THE PURPOSE OF MR. CLAYTON'S STRANDED COST ANALYSIS IN THIS CASE?

A. Mr. Clayton's study estimates stranded cost at 12/31/2005 based on information available today and the pricing scenarios provided by Mr. Schnitzer. His study is intended primarily as a test or a check on the reasonableness of the Duquesne plan. Specifically, if Mr. Clayton's study demonstrates that net stranded costs will exist at 12/31/2005, then it is likely that Duquesne's rate cap will not overrecover transition charges. The exact amount of his stranded cost determination is not important, only the fact that it exceeds zero. In other words, the purpose of Mr. Clayton's stranded cost study is to demonstrate the reasonableness of Duquesne's plan, not to quantify stranded cost.

Q. DOES MR. CLAYTON'S "TEST" SUPPORT THE REASONABLENESS OF DUQUESNE'S PLAN?

A. No. At best, he demonstrates that it is possible that Duquesne might have stranded costs remaining by 2006, but not that it is probable.

Q. PLEASE EXPLAIN.

A. As I mentioned earlier, if the additional accelerated depreciation from the merger (i.e., $160 million) is considered, Mr. Clayton's own estimate of stranded cost is a range of $393 million negative to $263 million positive -- a midpoint of a negative $65 million. However, even these results substantially overstate stranded cost. For example, during the rate cap period, Duquesne could free up additional dollars for accelerated depreciation by shutting down uneconomic plants such as Perry and Elrama, substantially lowering 12/31/2005 stranded cost. Additionally, Mr. Clayton's analysis ignores margin contributions from life extension of the Company's coal plants. He excludes life extension not because it is improper, but because he believes it is best considered at a later date, e.g., in the 2003 reassessment. My own analysis, however, suggests that life extension could provide over $200 million of 2006 NPV margins as a stranded cost offset.

Thus, while Mr. Clayton's study indicates that stranded costs at 12/31/2005 under its plan are possible, a more careful and critical review suggests that it is unlikely, particularly when merger savings are considered. Duquesne's plan does not pass Mr. Clayton's test.

Q. SUPPOSE THE FINAL VALUATION FINDS NEGATIVE STRANDED COSTS. IS THAT A PROBLEM?

A. It may be. Duquesne's position is that negative stranded costs at that time could be handled by an early termination of the CTC. That may or may not avoid an overcollection. The key point is even under the early termination solution (e.g., in 2004), Duquesne customers must wait a very long time before receiving any rate relief.

Q. IS THE ROE SPILLOVER A USEFUL CONSUMER PROTECTION?

A. No, it is not. First, the threshold of 12.0 percent for earnings accumulation is set far too high, in my judgment, far above Duquesne's cost of equity. Second, Duquesne can withdraw earnings from the fund to maintain an earnings floor of 11.0 percent, also in excess of its cost of equity. More importantly, it would not be difficult at all for Duquesne to evade overearnings contributions to accelerated depreciation. For example, excess earnings (or "earnings withdrawals") could be used to fund marketing efforts or rate discounts associated with unregulated market transactions.

Q. DO YOU SUPPORT THE REQUESTED 1.9 MILL RATE INCREASE?

A. No. Mr. Clayton's own projections indicate that Duquesne's earnings are expected to be very strong. Most important of all, Duquesne already has among the highest rates in Pennsylvania, particularly for residential customers. A further rate increase, which Duquesne clearly does not need, should not be permitted.

Q. WHAT IS YOUR REACTION TO THE "FINAL VALUATION" PROPOSAL?

A. The combination of the rate cap/final valuation proposal appears to be motivated by the Company's perception that there is too much uncertainty to reliably estimate stranded cost, and they therefore seek to defer the matter to 2003 or 2004. It is my understanding that it is the purpose of this proceeding to resolve stranded costs and its recovery, not to defer it to a future proceeding. While I concur with Company witnesses that performing market valuations on long-lived plants is a difficult undertaking, the same will be true in 2003. Deferring the task of performing a market valuation and convening a panel of experts will not dispel the uncertainty and controversy.

I must also question the auction method of establishing the annual market price benchmark. My concern is that this will establish a depressed market price proxy, leading to overstated CTC charges at ratepayers' expense and to the benefit of Duquesne.

As Duquesne participates in the emerging competitive market, it will be seeking to market its power supply to customer groups at the highest possible prices in order to maximize its revenue stream. A passive wholesale auction, with no price negotiation, is hardly consistent with the aggressive marketing and revenue maximization we would expect of Duquesne.

Moreover, there is no guarantee or even reason to believe that Duquesne's retail customers will be able to purchase their power supply at these auction prices. Duquesne has offered no assurance that the auction prices will be available to its customers.

Finally, my most serious objection to Duquesne's plan is that it eliminates the possibility of any rate reductions during the transition period.[3] Given Duquesne's very high rates, an effort should be made to lower rates while providing for reasonable stranded cost recovery rather than deferring rate reductions until 2006 (or even later).

Q. WOULD THE FINAL VALUATION METHOD AFFECT DUQUESNE'S INCENTIVE TO CONTROL COSTS OR IMPROVE ASSET VALUE?

A. It might. Knowing that its generation assets will be revalued in 2003, and the valuation at that time will govern stranded cost recovery, Duquesne's incentives to mitigate stranded cost and maximize asset value will be weakened. Poor cost control performance during the intervening years will show up as reduced market value of its power plants in 2003. Ratepayers will incur at least some of that risk under Duquesne's plan.

[3]As part of its merger case, Duquesne offers a rate reduction for distribution rates in 2001 of $25 million.

Q. DOES DUQUESNE'S PLAN PROVIDE FOR A SHARING OF THE COSTS OF THE COMPANY'S UNECONOMIC PLANTS?

A. No. My reading of the plan is that it requires 100 percent stranded cost recovery, including the full return of and a return on its highly uneconomic plants such as Perry and Beaver Valley 2.

Financial Considerations

Q. WHAT IS THE FINANCIAL OUTLOOK FOR DUQUESNE?

A. As demonstrated by Mr. Clayton, Duquesne's financial position is very strong. As shown on Exhibit DJC-2, the Company's earned return on equity has averaged more than 12 percent since 1993. More importantly, his transition period financial projections demonstrate that at the capped rates, Duquesne will generate substantial revenues in excess of the "normal" cost of service. The Company's plan would use this excess for accelerated amortization and depreciation of its generation assets to reduce stranded cost exposure. Mr. Clayton's financial forecast calculates the accelerated amounts which just allows the Company to earn an 11.5 percent rate of return during each year of the transition period.

Q. CAN YOU ILLUSTRATE THE AMOUNT BY WHICH RATES EXCEED THE STANDARD COST OF SERVICE IN MR. CLAYTON'S FORECAST?

A. Yes. This is illustrated on Schedule MIK-2. Mr. Clayton's forecast of the transition period includes $259 million of accelerated depreciation and $25 million per year, or $175 million in total, for acceleration of the Beaver Valley 2 lease. Mr. Clayton assumes in his forecast an earned return on equity (ROE) of 11.5 percent. Reducing the ROE to 10.0 percent would add another $136 million to the excess, for a total of $570 million. In addition to these items, his transition period forecast assumes $180 million of accelerated

depreciation of the Perry nuclear plant from the 1996 Ft. Martin settlement and a 1995 initiative.

One other aspect of the financial forecast should be considered. The forecast assumes that three apparently uneconomic plants (Elrama, Perry and Beaver Valley 2) will continue to operate during the transition period. If these plants instead were to shut down rather than continue to run, Duquesne could save more than $200 million in net operating expenses, after accounting for the added cost of purchasing replacement power (based on Company market prices). According to its forecast, the Company intends to continue to operate these plants through the end of their book lives. Presumably, the Company expects that the plants will become economic at some future time. However, there is no need for ratepayers to subsidize operating losses on these plants during the transition period.

These various items discussed above suggest that the capped rates exceed the "standard" cost of service (i.e., no acceleration, a 10.0 percent ROE and no uneconomic operating costs) by more than $1 billion during the transition period. Additionally, if the merger is completed, there would be a substantial further savings during the transition period.

Q. PLEASE EXPLAIN WHY A RATE REDUCTION IS NEEDED?

A. While I recognize that Duquesne's stranded cost exposure is substantial, this must be balanced against the needs of the Company's ratepayers. As shown on Schedule MIK-3, page 1 of 2, Duquesne's rates are the second highest in Pennsylvania, with only PECO Energy's being higher. The Company's average residential rate is 12.2 cents per kWh, which is nearly 50 percent above the national average.

The Company's plan in this case provides no rate reduction until the end of the transition period in 2006 (unless an early termination is triggered). In fact, the Company

is actually seeking a small rate increase at this time. Duquesne does propose a distribution rate reduction to take effect in 2001, if the merger is completed.

Q. MR. CLAYTON SUGGESTS THAT DUQUESNE'S RESIDENTIAL RATES ARE NOT UNDULY HIGH, AND INTERCOMPANY COMPARISONS CAN BE DISTORTED BY AVERAGE CUSTOMER SIZE. DO YOU AGREE?

A. Mr. Clayton has a valid point in noting that the cents per kWh is a less than perfect measure of the cost of electric service. Specifically, intercompany cents per kWh comparisons can sometimes mislead if customer load patterns differ.

In order to take that criticism into account, I compiled residential "typical bills" for 500 kWh and 1,000 kWh per month, as published by the Edison Electric Institute (EEI). This is a very common method for making intercompany comparisons of the cost of electric service. While Duquesne's relative position appears somewhat better using this measure, as compared to pure cents per kWh, it does not change the underlying conclusion. Duquesne remains the second most expensive electric utility in Pennsylvania for residential service and continues to be far above the national average.

By any standard, Duquesne's residential rates are burdensome.

Q. YOUR TESTIMONY DISCUSSES THE NEED IN THIS CASE FOR A REDUCTION IN RETAIL RATES. IF A RATE REDUCTION RESULTS IN THIS CASE, DOES THAT AFFECT ANY OF THE STRANDED COST ADJUSTMENTS?

A. Yes, it would. One of the claimed transition cost items is the cost to Duquesne of the rate discounts ("incentive credits") associated with the Company's pilot program. As noted by Mr. Catlin, Duquesne has deducted the expected cost of its pilot program incentive credits from the accelerated writedown of its Beaver Valley 2 lease obligation scheduled to take place in 1998 under the Fort Martin settlement. During informal discovery, Mr.

Clayton indicated that the amount of the incentive credits recorded was based on Duquesne's current rates. In addition, the estimate is also based on projected levels of customer participation in the pilot. It is possible that this proceeding will result in a reduction in Duquesne's retail rates which will offset some or all of the 10 percent discount being given to pilot program participants. In addition, the level and/or timing of participation may reduce or increase Duquesne's pilot program incentive credits compared to its forecast. Accordingly, I recommend that the amount of the pilot program incentive credits recognized as a stranded cost should be adjusted to reflect the results of this proceeding with respect to Duquesne's rates and the actual level of program participation prior to the implementation of the final CTC.

III. ANALYSIS FRAMEWORK

Q. PLEASE DESCRIBE MR. CLAYTON'S ANALYTIC FRAMEWORK FOR DETERMINING OWNED GENERATION STRANDED COST.

A. Mr. Clayton uses a cash flow or "margins" analysis to calculate the stranded cost associated with each Duquesne generating unit. The model calculates for each generating unit and each year the market revenue which the unit will provide minus all ongoing operating costs. Those costs would include fuel (and related items), fixed O&M, variable O&M, taxes other than income, capital additions (treated as expenses) and an allocation of A&G. The result is a stream of cash flow margins for that unit. Mr. Clayton then takes the net present value (NPV) of that stream and adjusts the NPV total for income taxes.

This after-tax NPV total is an offset to stranded cost. Mr. Clayton also calculates the NPV of decommissioning costs, which is treated as an addition to stranded cost. For example, assume the net book value of the generating unit at the beginning year of the study is $1 million, the NPV of after-tax margins is $300,000 and the NPV of decommissioning is $50,000. Stranded cost for that unit would be $1,000,000 minus $300,000 plus $50,000 = $750,000.

It should be noted that Mr. Clayton's stranded cost margin analysis begins in 2006 and extends until the unit's assumed retirement date. Thus, all of his NPVs are as of 12/31/2005.

Q. WHAT IS THE SOURCE OF HIS MARKET REVENUES?

A. The market revenues are based on two market price scenarios supplied to Mr. Clayton by DLC witness Schnitzer. These two market price scenarios result in the range of stranded cost results which Mr. Clayton reports.

Q. CAN MR. CLAYTON'S ANALYSIS PRODUCE NPV NEGATIVE MARGINS?

A. Yes, that is possible. That situation would arise if the operating expenses for the plant (including necessary capital additions) exceed market revenue. That result would imply that continued operation of the plant is uneconomic. In such a case, the proper treatment is to set the negative result equal to zero, i.e, there is no margin offset to net book value. It is my understanding that Mr. Clayton sets negative margins to zero, and I have done the same.

Q. WHAT DISCOUNT RATE DOES MR. CLAYTON USE TO COMPUTE HIS PRESENT VALUES?

A. He uses 7.83 percent, which is the Company's claimed net of tax cost of capital after removing the portion of the debt return which provides an income tax savings to the Company.

Q. IS MR. CLAYTON'S ANALYTIC FRAMEWORK ACCEPTABLE?

A. I do not object to the use of a cash flow margin approach to estimating stranded cost, provided that it is reasonably and correctly applied. Moreover, in order to be consistent with Mr. Clayton and to avoid introducing a completely different analytic framework, I have used his model, though with some important modifications.

The most obvious difference is that I am applying the model to a different time period, 1999 until plant retirement, whereas Mr. Clayton's study does not begin until 2006. This is because my study is designed to determine stranded costs as of the beginning of the transition period, whereas Mr. Clayton seeks to estimate stranded costs as of the end of the transition period and after seven years of accelerated depreciation and amortization. The rationale for approaching it this way was described earlier in my testimony.

Q. OTHER THAN THE TIME PERIOD, WHAT ARE YOUR DIFFERENCES WITH MR. CLAYTON?

A. While the general cash flow framework is acceptable, the results can be no more reasonable than the model inputs. My specific disagreements include the following:

- Discount rate. Mr. Clayton is correctly using a net of tax discount rate.[4] In my study, I make two adjustments to his discount rate. The first is to substitute a lower rate of return on equity, and the second is to remove debt reacquisition and issuance costs.

- Market revenue. Mr. Clayton has incorporated the market revenue stream based on Mr. Schnitzer's two scenarios. My analysis incorporates OCA witness Douglas Smith's revenue and fuel cost projections. I also incorporate Mr. Smith's estimates of non-fuel variable O&M in place of Company estimates.

- Productivity. After a period of adjustment, Duquesne projects that its non-fuel generation expenses trend upward with inflation. I believe it is reasonable to factor in some productivity improvement in those later years which would be motivated by a competitive market.

- Power plant life extension. The Company's study makes the overly conservative assumption that most of its coal plants will be retired at the end of their book lives, typically 40 years. As market prices rise, however, it is far more realistic to expect that Duquesne will extend plant lives. This has been common practice within the industry. Life extension will significantly and cost-effectively enhance the revenue stream, thereby reducing stranded cost.

- Fossil decommissioning. Duquesne has included substantial costs in its study for the eventual decommissioning of its fossil fuel plants. As OCA witness Catlin explains, the inclusion of these costs is improper. I therefore have eliminated fossil decommissioning from the analysis.

- Nuclear decommissioning. Nuclear decommissioning costs in excess of current trust fund levels should be taken into account in the analysis. Mr. Catlin has supplied his estimates of these incremental requirements during the transition period, and I have calculated the NPV of these costs at 1/1/99.

- Working capital. Mr. Clayton does not recognize working capital (i.e., fuel inventory and materials and supplies) as an ongoing cash cost and therefore excludes it from his study. I have added working capital to the stranded cost study.

[4]This is the correct discount rate because he applies it to net of tax margins or net revenues. If he made no tax adjustment, then the correct discount rate would have been the pre-tax rate of return.

- Merger savings. Duquesne is presently seeking regulatory approval of its merger with Allegheny Power, and it anticipates that the merger will provide a savings in generation costs. However, its filed stranded cost analysis does not incorporate these savings. If and when the merger closes, it would be proper to account for merger savings as a reduction in estimated stranded costs.

My adoption of Mr. Smith's market revenues also requires making certain consistency adjustments. Specifically, I have adjusted Duquesne's plant expense projections to the inflation rates embedded in Mr. Smith's study. Since he is using a generally higher inflation rate, this is an upward adjustment to those costs. Additionally, Mr. Smith projects higher fuel costs than does Duquesne, and I have incorporated those higher fuel costs.

Q. DOES MR. CLAYTON EVALUATE NUG STRANDED COSTS?

A. No. Duquesne has no long-term NUG contracts and therefore no NUG stranded costs.

Q. GIVEN YOUR DIFFERENCES WITH MR. CLAYTON, WHAT RESULTS DID YOU OBTAIN?

A. My initial stranded cost model results as of 12/31/98 are shown on page 2 of Schedule MIK-1. That schedule lists the net book value of each plant at 12/31/98, the NPV of the after-tax cash flow margins and NPV decommissioning increments. As recommended by Mr. Catlin, decommissioning is recognized only for the nuclear units.

It should be noted that the net book value for Beaver Valley 2 includes the NPV cost of the lease, whereas the Company includes the lease as a regulatory asset. My proposed treatment correctly recognizes that Beaver Valley 2 in reality is "owned" by Duquesne, and the sale leaseback is nothing more than a financing vehicle. This treatment is merely one of classification and does not affect the calculation of the stranded cost total. As a result, the net book value of Duquesne's (operating) generation assets is $1,362.32 million at 12/31/98.

Based on Mr. Smith's projections and Duquesne's (inflation adjusted) expense estimates, these plants will provide NPV after-tax margins totaling $180.1 million. This

is based on my 6.88 percent discount rate. Adding in $44.47 million for decommissioning, the stranded cost total for operating generating units (prior to my adjustments) is $1,226.7 million.

There are two additional stranded cost items on page 2 of Schedule MIK-1. I include $45.62 million for working capital and $64.06 million for plants in cold reserve (including remaining Warwick coal mine net book value), bringing the initial stranded cost total to $1,336.4 million. These are my basic model results prior to certain adjustments which I make outside the model.

Q. HOW DO YOUR ADJUSTMENTS CHANGE THE RESULTS?

A. I show the effects of three adjustments on page 3 of Schedule MIK-1. These include a productivity increase adjustment ($25.32 million), power plant life extension ($170.72 million) and generation-related merger savings ($152.28 million). All of these adjustments are 1/1/99 NPV figures based on the 6.88 percent discount rate. With these adjustments, the total owned-generation stranded costs become $1,140.3 million stand-alone and $988.1 million with the merger savings.

All figures cited above and on Schedule MIK-1 are total company. A small portion (0.1 percent) of these stranded costs is allocable to the FERC jurisdiction.

Q. WHAT IS THE SOURCE OF THE COLD RESERVE STRANDED COST?

A. This is merely the net book value at 12/31/98, as reported by the Company, with a $5 million downward adjustment. Since the Company has no specific plans for returning those units (Phillips and Brunot Island) to service, by definition the net margins offset must be zero. Of course, it is possible that those units have some market value and as market prices rise might someday return to service. But I have made the conservative assumption that market value is zero.

It should be noted that this cold reserve capacity is not used and useful in providing service to Duquesne's customers. Consequently, it is proper that Duquesne recover the principal balance through transition charges with no return.

Q. PLEASE EXPLAIN WHAT ADJUSTMENT YOU HAVE MADE TO THE NET INVESTMENT IN THE COLD RESERVE UNITS.

A. As part of the Ft. Martin Agreement discussed by Mr. Clayton in his testimony, Duquesne agreed to restore the Brunot Island units in cold reserve to service. In conjunction with that commitment, $5 million of the net proceeds from the sale was designated for the refurbishment of Brunot Island Units 2B and 3.

Duquesne has taken the position that this designation of funds was intended only to identify the source of the capital to be used to pay for the refurbishment and was not intended to provide any benefit to ratepayers. However, a more reasonable interpretation is that the $5 million was, in fact, intended to reduce the costs to ratepayers of returning those units to service. If this was not the intent, there would be no reason for the settlement to address the use of the proceeds to refurbish Brunot Island. Consistent with this interpretation, I have reduced the unrecovered net investment in the Brunot Island units in cold reserve by $5 million.

I would note that a portion of the proceeds may have been used to return Unit 2B to service. To the extent that this occurred, the investment in Unit 2B would reflect the amount expended and is therefore captured in my calculated stranded costs. Accordingly, it is appropriate to deduct the full $5 million from the balance of the investment still in cold reserve.

Q. YOUR RESULTS ON SCHEDULE MIK-1, PAGE 2 OF 3, SHOW ZERO NET MARGINS FOR SEVERAL OF DUQUESNE'S PLANTS. WHY IS THAT?

A. All of the nuclear plants and several of the coal units are modeled as having negative net present value operating margins as of 12/31/98. In the case of the nuclear units, this may be partly due to the fact that Mr. Smith adopted less optimistic plant availability factors than the Company making his analysis conservative for those units.

In the case of the coal units, operating costs (including the A&G allocation) plus capital additions in the early years exceed revenue. In most cases, margins turn positive in the later years as output levels and market prices rise. For some units, the positive margins in the later years are not sufficient to cover the early year losses. Again, this is partly due to the fact that, in some instances, Mr. Smith's unit output estimates are conservatively low -- lower than the Company's levels of output.

Q. HOW DID YOU TREAT THESE NEGATIVE MARGINS?

A. A negative net present value result must be treated as zero, since to do otherwise would assume a negative market value for the unit. A negative result, however, does not necessarily mean that the plant should be retired. It may be economical to continue to operate the plant if operating expenses can be reduced and/or if the plant can operate at higher output levels than included in Mr. Smith's analysis. Moreover, if projected early year losses are substantial but later year margins are positive, it may make sense to temporarily shut down the plant and restart it when market conditions warrant a few years hence. This might be an effective mitigation strategy.

Q. HAVE YOU CONSIDERED THIS APPROACH FOR ANY DUQUESNE PLANTS?

A. Yes. The Cheswick plant appears to be potentially one of Duquesne's most valuable assets. Yet, because of early year losses, its NPV margins are negative by about $37

million. After 2005, margins are consistently positive. For modeling purposes, I assume the plant is placed in cold reserve until 2006 to avoid those losses. The 12/31/98 NPV of the post 2005 positive margins is $41.2 million, and that is what I reflect on page 2 of Schedule MIK-2.

I do not mean to imply that the Cheswick unit must be temporarily shut down. The large near term operating losses instead can be mitigated through cost control or expanded sales from the plant over and above the levels estimated by Mr. Smith. My only point is that the stranded cost study need not reflect those early year losses. My approach is merely one method of mitigation.

Q. IS THE TEMPORARY COLD RESERVE APPROACH APPLICABLE TO OTHER DUQUESNE UNITS?

A. Yes, potentially it is. I could have obtained some additional NPV market value if I had used that method with certain other Duquesne units. However, the net benefit from those units is much smaller than with Cheswick and, therefore, I limited this adjustment to the Cheswick plant. Consequently, I show zero market value for several of the Duquesne coal units.

Q. DO YOU HAVE ANY CORRECTIONS TO MR. CLAYTON'S COMPUTER MODEL?

A. I have one minor computational correction. In discounting his cash flow stream to 1/1/99, his model applies a full year of discounting to the first year. I believe it is more accurate only to apply a half-year of discounting to the first year. The half-year method assumes that the cash flow is received evenly throughout the year, whereas the full year of discounting assumes that Duquesne receives its cash flow at year's end. Since the former is more realistic, a small correction (equivalent to a half-year of discounting) is needed to the NPV cash flows produced by his computer model.

IV. DESCRIPTION OF ADJUSTMENTS

Selection of Discount Rate

Q. HOW HAVE YOU DEVELOPED YOUR 6.88 PERCENT DISCOUNT RATE?

A. As stated earlier, I have no conceptual disagreement with Mr. Clayton's use of a net of tax discount rate because the cash flow margin results are themselves adjusted from being pre-tax to after-tax. Thus, the net of tax discount rate provides consistency.

In following Mr. Clayton's approach I have found it necessary to make two adjustments. First, the claimed cost of equity in Duquesne's discount rate, 11.5 percent, is far too high. In the PECO Energy securitization case (Docket No. R-00973877), this Commission approved a return on equity of 10.0 percent, and that return should apply to Duquesne as well. As shown on Schedule MIK-5, I substitute the 10.0 percent for the 11.5 percent.

The second adjustment concerns recovery of debt reacquisition costs. The conventional way to recover these costs is through rate of return. Duquesne's overall rate of return includes debt reacquisition costs as additional interest expense (thereby increasing the embedded cost of debt), and the Company also subtracts the unamortized balance (about $85 million) from its outstanding debt balance. This has the effect of increasing the equity ratio and therefore rate of return. As shown on my Schedule MIK-5, I have reversed both adjustments. As a result, Duquesne's embedded cost of debt falls from the claimed 8.51 percent to 7.57 percent, and the equity ratio also declines.

As a result of both my ROE reduction and removal of debt reacquisition costs, the discount rate falls from Mr. Clayton's 7.83 percent to 6.88 percent.

Q. DOES YOUR ADJUSTMENT DENY DUQUESNE RECOVERY OF DEBT REACQUISITION COSTS?

A. No. It simply removes it from rate of return. Mr. Catlin provides Duquesne a full recovery of the claimed amount over the transition period, including a return on the unamortized balance. My adjustment is merely intended to avoid overrecovery, given Mr. Catlin's full recovery treatment.

Nuclear Decommissioning

Q. HOW HAVE YOU COMPUTED THE NUCLEAR DECOMMISSIONING COST INCREMENT?

A. Mr. Catlin has computed the annual amounts for each of Duquesne's nuclear units which it needs to collect each year of the transition period to fully fund decommissioning. These annual ratepayer contribution amounts are shown on his Schedule TSC-2. To translate these annual contributions into a stranded cost, for each nuclear unit I discounted Mr. Catlin's decommissioning revenue requirement stream back over the seven years to 1/1/99 using the 6.88 percent discount rate.

Working Capital

Q. PLEASE DESCRIBE YOUR METHOD FOR DETERMINING STRANDED COSTS ASSOCIATED WITH WORKING CAPITAL.

A. The Company identifies its power plant working capital balance at 12/31/98 as being $61.53 million. This consists of fuel inventory and materials and supplies at each plant. As I understand Mr. Clayton's study, he makes no claim for working capital stranded cost.

I believe some recognition of working capital is proper, and I start with the Company's balance of $61.53 million. There is, however, a net margin offset. In the last year of the plant's life, I assume that working capital balances will either be consumed

(thereby reducing plant expenses that year) or sold off. Thus, for each generating unit, I compute the NPV of the working capital amount (i.e., the 12/31/98 amount) as of the retirement year of the unit. Moreover, I specify the retirement year assuming 15-year life extension for Duquesne's coal plants (other than Elrama). To compute the NPV figures, I use a real discount rate of 4.0 percent rather than 6.88 percent, in order to recognize that the market value of these inventory amounts will increase with inflation. This procedure provides me with an NPV after tax margin of $15.91 million which is an offset to the 12/31/98 balance of $61.53. Thus, working capital stranded cost becomes $45.62 million.

Fossil Decommissioning

Q. WHAT IS DUQUESNE'S CLAIM FOR FOSSIL DECOMMISSIONING?

A. Duquesne's filed case includes $112.9 million for fossil decommissioning at its 7.83 percent discount rate. This amount is the NPV total at 12/31/2005. If discounted at that rate to 12/31/98, it obviously would be substantially less (roughly $66 million).

Q. WHAT IS THE OCA'S POSITION ON FOSSIL DECOMMISSIONING?

A. As discussed by OCA witness Catlin, the claimed costs associated with the decommissioning of the Company's fossil generating costs should not be included in the stranded cost study for recovery from customers. However, if the Commission determines that projected fossil decommissioning costs should be included, Mr. Catlin urges that Duquesne's estimate be revised to take into account the 15-year life extension of coal units, along with the OCA's inflation rate and discount rate. Moreover, the amounts should be discounted back to 12/31/98, not 12/31/2005.

Q. IN LIGHT OF MR. CATLIN'S TESTIMONY, HOW HAVE YOU ADJUSTED DUQUESNE'S STUDY?

A. I have excluded the claimed fossil decommissioning NPV amounts from my stranded cost determination.

Productivity Enhancements

Q. WHY ARE YOU ADDRESSING DUQUESNE'S PRODUCTIVITY IN YOUR TESTIMONY AND STRANDED COST ANALYSIS?

A. The issue of productivity and efficiency is central to the introduction of competition into electric generation. Certainly, one of the primary reasons of moving from a system of regulated monopoly, subject to cost-plus pricing, to competition is the belief that competition will motivate new efficiencies and cost control benefits not attainable under regulation. Moreover, such efficiencies are not merely a one-time or episodic effort at cost control (e.g., a utility downsizing initiative at a given point in time) but will be continual. Once deregulated, the owners of generation assets will be seeking ways of controlling costs and improving productivity on an ongoing basis.

In the context of electric restructuring cases, in Pennsylvania and elsewhere, such efficiencies are referred to as a form of "mitigation," i.e., offsets to reduce uneconomic costs. Pennsylvania electric utilities are expected to address such mitigation efforts in their respective filings.

Q. IF COMPETITION SERVES TO MOTIVATE FUTURE COST SAVINGS EFFICIENCIES, AS YOU SUGGEST, WHY SHOULDN'T THOSE EFFICIENCIES GO TO SHAREHOLDERS?

A. In the absence of a stranded cost recovery mechanism, this is exactly what would happen. All cost reductions (net of tax) would go to the Company's bottom line, and in such a case, there would be no need to discuss the efficiency gains any further.

The existence of a stranded cost recovery mechanism changes all of that. Take the case of a utility seeking 100 percent stranded cost recovery for its generation assets based on a projection of its embedded costs. The utility seeks to charge its captive ratepayers a transition fee for the difference between its embedded costs and market prices, so that the utility is fully compensated for its above market costs. If the utility reduces its generation costs in the future in response to competitive pressures, but does not reflect such cost savings in its stranded cost projections, then it will have overstated its stranded costs. If the utility's stranded cost figure is accepted, then (1) customers will pay transition charges which, in reality, exceed 100 percent of stranded costs; and (2) competitively induced efficiencies will go to the utility, not ratepayers. For this reason, it is imperative to recognize the competitively-induced efficiencies in the stranded cost determination itself.

Q. ISN'T IT TRUE THAT IN COMPETITIVE MARKETS EFFICIENCY GAINS GO TO SHAREHOLDERS?

A. That is partly true. In a competitive market, firms which achieve productivity gains or succeed in reducing costs below those of their market rivals may reap the reward in the form of excess profits (i.e, profits above the industry average level or cost of capital). That is not what my testimony above is referencing. Rather, I am referring to normal efficiencies associated with moving from cost plus regulation to competition. Merely

meeting the competitive norm (in terms of operating efficiency) does not necessarily imply high profits in a deregulated market.

Q. IN THE CASE OF DUQUESNE, HASN'T IT REDUCED ITS GENERATION COSTS IN RECENT YEARS?

A. Yes. Mitigation is discussed extensively in Duquesne's filing, and the Company has reflected improvements in its cost projections compared to its historically high costs, particularly for its nuclear units. While these changes occurred under standard regulation, such measures are consistent with a transition to competition.

My concern is not with Duquesne's historic mitigation measures, such as those discussed in Mr. Clayton's testimony. Rather, the problem is that the restructuring plan does not adequately identify or incorporate future cost mitigation efforts or productivity gains. The projections included in Mr. Clayton's study simply assume that certain expense items (after the initial transition years) increase with the general rate of inflation. Competition, however, implies a continual search for cost savings.

Q. WHAT TYPE OF PRODUCTIVITY SAVINGS CAN BE EXPECTED FROM COMPETITION?

A. It must be recognized that not all utility embedded costs can be mitigated by increases in productivity. In particular, the "sunk" costs of existing plant -- return on rate base, depreciation and associated income taxes are not amenable to efficiency gains. Utility operating costs, however, can and probably will be reduced as competition is introduced. This could include fuel costs, non-fuel O&M, Administrative and General expenses and even capital additions needed to maintain the units and extend their lives.

Q. ARE YOU AWARE OF ANY ATTEMPTS TO QUANTIFY GENERATION OPERATING COSTS SAVINGS FROM COMPETITION?

A. Yes. In 1996, the Staff of the Federal Energy Regulatory Commission (FERC) conducted an analysis of utility industry efficiency gains resulting from the introduction of wholesale competition from transmission access.[5] The FERC Staff concluded that wholesale competition will lead to generation operating cost savings for the industry ranging from $3.8 to $5.4 billion per year, depending upon the study scenario. Most of these savings relate to fixed O&M expenses at existing plants, as competition motivates cost reductions. Additionally, cost savings are expected to come from improved unit heat rates and plant availability. According to the FERC Staff study, the fixed O&M savings (about $2.1 billion per year) equates to a 15 percent reduction in industry-wide (generation) fixed O&M costs. The FERC study further suggests that an even higher level of savings, about 25 percent, should be considered. (FERC, pp. 5-67 and 5-68).

A recent study conducted by the U.S. Department of Energy (DOE) provides projections of the rate impacts associated with the introduction of retail access nationwide.[6] The DOE analysis assumes that non-fuel operating costs for existing power plants will decline by 25 percent due to the onset of retail competition. The 25 percent cost reduction is merely the study's "Reference Case." The study also considers a "high efficiency" scenario in which competition induces a 40 percent decline in non-fuel operating costs (i.e., non-fuel O&M plus A&G). (DOE, page 16)

[5]The efficiency analysis is submitted as part of the Final Environmental Impact Statement accompanying the FERC's transmission open access and stranded cost rulemakings. FERC Docket Nos. RM95-8-000 and RM94-7-001, April 1996, FERC/EIS-0096.

[6]Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities. Energy Information Administration, August 1997, DOE/EIA-0614.

Q. HAVE PRODUCTIVITY GAINS FOR ELECTRIC UTILITIES BEEN RECOGNIZED IN ANY REGULATORY DECISIONS?

A. Yes. In 1995, the Maine Public Utilities Commission approved an incentive regulation plan for Central Maine Power Company.[7] This plan, which created strong incentives for cost control, included a price cap formula which assumes a 1.0 percent per year productivity gain.

Q. HOW HAVE YOU APPLIED THE CONCEPT OF PRODUCTIVITY GAINS TO DUQUESNE'S STRANDED COSTS?

A. I have reviewed the information in the filing concerning non-fuel operating costs and the projections sponsored by Mr. Clayton and other Duquesne witnesses. According to the Company, budget figures for non-fuel O&M have been developed for the transition period and escalated at the general rate of inflation thereafter. Duquesne's A&G costs assigned to generating units appear to be merely escalated at the general inflation rate.

I would note that the testimony of Mr. Duckworth and Mr. Nelson provides information on historic generating unit operating costs versus projected, and this information shows that the Company is assuming cost control improvements. As Mr. Nelson explains (page 3), O&M expenses are increased from 1999 levels by inflation, subject to work force reductions until 2002.

I believe that it is reasonable to consider additional efficiency gains for Duquesne, particularly after the first few years of retail competition. I compute a productivity gain adjustment on Schedule MIK-6. My adjustment assumes that Duquesne achieves a 1.0 percent per year gain in productivity beginning in 2003 and extending for ten years. That is, I cap the productivity gain at approximately 10 percent in 2012 and hold it constant at that level over the remainder of the study period. This productivity gain adjustment is

[7]MPUC Docket No. 92-345, Phase II, January 10, 1995.

applied only to the Company's non-fuel O&M and A&G expenses, even though there are likely to be other categories of costs which are also susceptible to efficiency improvements. Moreover, my analysis excludes Beaver Valley 2, Perry and Elrama since I obtain negative margins for those units which indicates that they are uneconomic to operate.

It should be noted that this adjustment does not produce an actual reduction in these expenses -- merely a reduction in the rate at which A&G and O&M are projected to increase. That is, during the ten year period (2002-2012), instead of expenses increasing with inflation, they increase by 1.0 percent less than inflation.

Q. WHAT IS THE TOTAL VALUE OF YOUR PRODUCTIVITY ADJUSTMENT?

A. On a 1999 NPV basis, the productivity adjustment provides a savings of $25.32 million. In nominal dollars, this translates into a total reduction of projected fixed O&M and A&G expenses of less than 6 percent. It would be an even smaller percentage if my $25.32 million were compared to a total which includes the Perry, Beaver Valley 2 and Elrama operating expenses.

In my opinion, this is a conservative estimate of the cost control efficiencies which we can expect competition to provide. It is imperative that any Commission decision on stranded costs in this case give recognition to cost control efficiencies expected to be induced by competition.

Power Plant Life Extension

Q. WHAT IS THE TIME FRAME OF MR. CLAYTON'S STUDY?

A. As a general matter, Mr. Clayton calculates revenues lost over the book lives of the generation units. For the Company's major coal-fired generating plants, this assumes a useful life of approximately 40 years.

Q. IS IT COMMON IN THE ELECTRIC UTILITY INDUSTRY TO MAINTAIN MAJOR COAL-FIRED UNITS IN OPERATION BEYOND THEIR 40-YEAR BOOK LIVES?

A. Yes, based on my experience it is quite common. For example, PECO Energy included the life extension of three of its major coal-fired power plants in its restructuring case.

Q. GIVEN THAT LIFE EXTENSION IS COMMON PRACTICE, WHY HAS MR. CLAYTON ASSUMED RETIREMENT AT THE END OF BOOK LIFE?

A. It should be noted that for most of Duquesne's plants, book retirement dates are many years from now (Elrama is the only major exception). For Duquesne's coal-fired steam units, book retirement dates range from 2010 for Sammis to 2019 for Mansfield 3. Hence, Duquesne will not need to plan for life extension for a number of years which may explain the relative lack of attention to this issue. In fact, the OCA has received no life extension studies in response to its request. As Mr. Clayton explains (pp. 33-34), the issue of the most realistic remaining life is best considered at the time of Duquesne's proposed "final valuation" in 2003.

Life extensions of major coal plants will require significant capital outlays, and Duquesne believes that addressing life extension for its units at this time would be premature. In particular, whether or not life extension investments will be cost effective will depend upon both the market price outlook at that time and whether substantial additional environmental controls (beyond those already planned) or other such costs will be required. Mr. Clayton acknowledges that life extension studies will be prepared and made available for the 2003 valuation.

Q. IS THE COMPANY'S POSITION REASONABLE?

A. The Company's position is certainly understandable if the purpose is merely one of reporting an integrated resource plan. In reality, the Company would defer life extension

investment decisions until the years shortly before book retirement date due to the inherent uncertainty of making such decisions this far in advance.

The Company's position, however, is not reasonable in the context of a stranded cost study intended to provide the basis for customer transition charges. Such a study must incorporate all reasonable mitigation measures to reduce costs or enhance the plant revenue stream, and life extension is a potential mitigation which Duquesne should consider.

The Company is also correct that future new environmental regulations (not reflected in the Company's study) could affect the attractiveness of life extension. However, it is one-sided to arbitrarily assume, for stranded cost purposes, that these unspecified environmental requirements would prevent life extension for every unit.

Q. MR. CLAYTON STATES THAT LIFE EXTENSION SHOULD BE CONSIDERED AT THE TIME OF THE FINAL VALUATION IN 2003, BUT NOT AT THIS TIME. DO YOU ACCEPT THIS VIEW?

A. No, I do not. First, it is the purpose of this proceeding not some future proceeding to establish stranded cost. Hence, I do not accept Duquesne's framework with its 2003 "final valuation." Second, even within that framework, life extension benefits must be considered at this time. This is because Mr. Clayton's post 2005 stranded cost study is intended as a "test" of Duquesne's seven-year rate cap plan. If life extension is ignored, then Mr. Clayton's test is potentially biased and distorted. He may find positive stranded costs when including life extension could reverse that finding.

Q. WHAT ARE TYPICAL COSTS ASSOCIATED WITH LIFE EXTENSIONS OF COAL PLANTS?

A. Such costs can vary depending on plant and site specific factors, and unfortunately, detailed estimates are not available for Duquesne's coal plants. However, useful

information was provided in the PECO Energy restructuring case for three coal plants (Conemaugh, Keystone and Eddystone). In addition, West Penn Power Company has life extended its Armstrong plant and has supplied budget figures for Mitchell 3 in its restructuring case. I show this information on Schedule MIK-7. This suggests that a *reasonable estimate for the cost of life extending a coal-fired power plant is roughly $200* per kW (or less) in today's dollars. In fact, the Mitchell 3 budget cost is approximately $106 per kW.

In light of this information, I have employed a "base case" cost of $200 per kW in 1997 dollars. However, in light of the environmental uncertainties and the possibility of other unknown costs being omitted from my study, I have also considered a capital cost of $300 per kW in 1997 dollars.

Q. HOW HAVE YOU CONDUCTED YOUR LIFE EXTENSION ANALYSIS?

A. As shown on Schedule MIK-8, I have prepared a separate screening study for each Duquesne coal unit, beginning with Sammis. Life extension benefits are calculated for an assumed 15-year extension period using projected market revenue (based on OCA witness Douglas Smith's projections) minus the sum of fuel costs, non-fuel O&M[8] (including capital additions) and life extension costs. Fuel costs and variable non-fuel O&M are also based on Mr. Smith's analysis and all costs in the analysis are based on the DRI inflation forecast which Mr. Smith uses for his market revenue and fuel expenses. Following Mr. Clayton's cash flow approach, the life extension investment is entered as a year 0 negative cash flow. In all cases, the initial year fuel costs, market revenues and *non-fuel O&M costs were escalated at the DRI 3.61 percent.*

[8]Non-fuel O&M expenses are based on company estimates averaged over the five years prior to book retirement. They include capital additions, taxes other than income, A&G and fixed O&M. These expenses are inflation adjusted to the first year of the life extension period and escalated at 3.61 percent thereafter.

Q. WHICH UNITS DID YOU SCREEN FOR LIFE EXTENSION?

A. I screened Sammis, Cheswick, Eastlake, and each of the three Mansfield units. As shown on Schedule MIK-8, in each case the life extension was shown to be cost effective at $200 per kW although cost ineffective for two units (Eastlake and Mansfield 1) at $300 per kW.

Q. WHAT ARE YOUR LIFE EXTENSION RESULTS?

A. I have summarized the NPV of life extension net benefits for the nine units on Schedule MIK-8, page 7 of 7. These benefits total $210 million using a "base case" cost of $200 per kW and $171 million using a $300 per kW cost, net of tax. Thus, a reasonable range of life extension net benefits would be $210 to $171 million expressed as 1/1/99 NPV at a 6.88 percent discount rate. To be conservative, I have selected this lower end net benefit figure as my adjustment to Duquesne's stranded costs.

Q. DID YOU CONSIDER NUCLEAR LIFE EXTENSION?

A. No, I did not. Duquesne has not yet considered nuclear life extension, and it therefore remains a possibility. It should be noted that the retirement dates for the nuclear units are 2015 for Beaver Valley 1 and 2026 for Beaver Valley 2 and Perry. Hence, life extension decisions for those plants are far in the future.

Merger Savings

Q. HAS DUQUESNE CONSIDERED THE EFFECT OF ITS PROPOSED MERGER WITH DUQUESNE ON ITS STRANDED COSTS?

A. Yes, in a limited way. The Company indicates a willingness to reflect $160 million of additional accelerated depreciation during the transition period if the merger is completed.

Q. SHOULD THESE SAVINGS BE RECOGNIZED?

A. They should be recognized if the merger is approved and completed.[9] Since the outcome of the merger will not be known until sometime in 1998, I believe it is necessary to consider stranded costs both with and without merger savings. It is improper, though, to totally omit merger savings from the stranded cost study.

Q. HOW HAVE YOU QUANTIFIED GENERATION-RELATED MERGER SAVINGS?

A. I have estimated those savings using the information in Mr. O'Brien's Exhibit MKO-2 in the merger docket (Docket No. A-110150F0015). Mr. O'Brien's study provides the year-by-year net merger savings (i.e., net of costs to achieve) for Duquesne each year through 2007. For example, in 1999 the net merger savings for Duquesne (net of costs to achieve) are $29.884 million. Mr. O'Brien also provides some information on merger savings for Duquesne by major function. According to his study, Duquesne's generation-related net merger savings (other than joint dispatch savings) are 48.34 percent of its net total merger savings during the first ten years.

Using this rule of thumb relationship, I calculate the year-by-year Duquesne merger savings relating to generation on Schedule MIK-9. After calculating Duquesne's generation savings, I add $2.5 million per year (escalated at 2.7 percent) for joint dispatch savings.[10] After 2007, the merger savings are assumed to increase by 2.7 percent per year. Since I have not applied the DRI inflation adjustment to these merger savings, the results on Schedule MIK-9 are conservatively low.

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[9]This statement is not meant to imply support by the OCA for PaPUC approval of the merger. The OCA is scheduled to file its testimony in the merger docket on November 14, 1997.

[10]Mr. O'Brien estimates dispatch savings of $2.5 million annually for Duquesne and each APS operating company. However, his study does not include an escalation factor. I have assumed escalation at 2.7 percent.

Q. WHAT ARE THE GENERATION-RELATED MERGER SAVINGS?

A. I estimate those savings at $152.28 million at 1/1/99 NPV on an after tax basis. These NPV net of tax savings provide an offset to stranded cost.

Q. SINCE YOU HAVE REFLECTED MERGER SAVINGS, SHOULD COSTS TO ACHIEVE THESE MERGER SAVINGS BE RECOVERED AS A TRANSITION COST?

A. No, that is not necessary. My merger savings on Schedule MIK-9 already net out an allocated share of Duquesne's (generation-related) merger costs to achieve. Therefore, a separate consideration of merger costs to achieve is not needed.

V. CONCLUSIONS

Q. WHAT RESULTS DID YOU OBTAIN FOR THE OWNED-GENERATION PORTION OF STRANDED COST?

A. Duquesne's owned-generation stranded costs are substantial, ranging from $988.1 million with the merger to $1,140.3 million on a stand-alone basis. What is striking about these results is that virtually the entire amount is attributable to Duquesne's three partially owned nuclear units. When life extension benefits are considered, there are no significant stranded costs associated collectively with the non-nuclear units, even when cold reserve capacity is included. Moreover, the nuclear units account for only about one-quarter of Duquesne's installed capacity.

There are two reasons why the nuclear units produce such a serious problem for Duquesne. First, the investment costs, and hence the net book values, are very high, despite the progress made under the Ft. Martin initiative. Second, the operating costs of these plants are very high making it very difficult to generate significant net margins from competitive market sales. Hence, there is little net revenue to offset net book value. There is little doubt that these plants should be considered to be "economic excess capacity" if this were a standard rate case.

Q. WHAT DOES THIS IMPLY CONCERNING STRANDED COST RECOVERY?

A. With respect to owned-generation stranded cost, Pennsylvania's statute does not guarantee 100 percent recovery. Rather, the utility is to recover a "just and reasonable" amount of stranded cost from its ratepayers.

Given the "just and reasonable" standard and the fact that virtually all of the owned-generation stranded cost would normally be considered "economic excess capacity," a sharing mechanism is clearly appropriate. One reasonable way of providing such a sharing would be to allow the recovery in transition charges of the principal amount of

the owned generation stranded cost over the seven-year transition period, but with no return applied to the unamortized balance.

Q. GIVEN THE JUST AND REASONABLE STANDARD, HOW HAS DUQUESNE PROPOSED THAT ITS OWNED-GENERATION STRANDED COSTS BE SHARED?

A. My interpretation of Duquesne's plan is that it provides no sharing at all. Potentially, all stranded costs are recovered under its seven-year frozen rates proposal. If its final valuation indicates stranded costs will exist at the end of 2005, Company witnesses suggest that Duquesne will seek recovery.

Q. IS DUQUESNE'S POSITION REASONABLE?

A. Given the circumstances, Duquesne's position that ratepayers must absorb 100 percent of stranded costs for the Company's uneconomic nuclear units is not reasonable. It is inconsistent with past ratemaking policy in Pennsylvania, which has not allowed a return on plant which was not used and useful. Duquesne's expensive nuclear plants are not used and useful in the sense that they do not provide a net economic benefit to customers. Shareholders who are accountable for these past nuclear investments, and who have benefited in recent years from the Company's favorable earnings, should bear some of the costs of these uneconomic investments. As mentioned above, not including a return on the stranded costs in the CTC would provide such a sharing.

Q. IS IT YOUR POSITION THAT DUQUESNE SHOULD NOT RECEIVE A RETURN ON ITS GENERATION ASSETS?

A. No. Denial of a return on the owned generating stranded cost amount does not mean that Duquesne cannot earn a return on its in-service generating plants. My analysis suggests little or no stranded costs, in the aggregate, for Duquesne's coal plants. Based on the

market price outlook, the Company can expect to earn reasonable, very attractive returns in the competitive market on those plants.

The stranded costs are limited to the nuclear assets. My stranded cost analysis includes no net operating revenue (i.e., net margins) for those plants. Duquesne, however, can earn positive margins on those plants if it lowers operating costs and improves performance. For example, OCA witness Smith's analysis includes much less optimistic nuclear plant availability than Duquesne itself believes it can achieve. Thus, given my stranded cost recovery recommendation, Duquesne has the potential to achieve earnings on its nuclear plants in the competitive market if cost control and operations are successful. In addition, I make the conservative assumption that Duquesne's cold reserve capacity has no market value.

Q. WHAT DO YOU CONCLUDE REGARDING MR. CLAYTON'S STRANDED COST ANALYSIS?

A. Mr. Clayton's study is merely a test designed to show that some positive amount of net stranded cost will remain at 12/31/2005 after the seven years of accelerated amortization and depreciation calibrated to a return of 11.5 percent. For a variety of reasons, I do not believe that he has successfully demonstrated that positive stranded costs are likely to exist at 12/31/2005. First, by avoiding uneconomic expenses, and accepting a return closer to its cost of capital, far more accelerated depreciation could be accomplished under the rate cap than is reflected in Mr. Clayton's study. Consequently, he overstates 12/31/2005 net book value. Second, important adjustments (such as life extension) were omitted from his stranded cost study. Third, his findings ignore merger savings. Taking all of these deficiencies into account, it is clear that Duquesne's plan fails Mr. Clayton's test.

1 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

2 A. *Yes, it does.*

APPENDIX A

QUALIFICATIONS OF MATTHEW I. KAHAL

MATTHEW I. KAHAL

Mr. Kahal is a senior economist and founding principal at Exeter Associates, Inc. His fields of expertise include energy economics, public utility regulation and financial analysis. Over the past decade, his work has encompassed electric utility integrated resource planning (IRP) and a wide range of utility financial issues. In the IRP area he has performed or supervised numerous studies concerning need for power, load forecasting, avoided cost and independent power contracting, Clean Air Act compliance and supply-side evaluations. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's more recent work has shifted to electric utility restructuring, mergers and competition in generation.

Mr. Kahal has testified on more than 150 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power contracts, merger economics and various other regulatory policy issues.

Education:

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidate - University of Maryland, completed all course work and qualifying examinations.

Previous Employment:

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park).

1975-1977 - Lecturer in Business/Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than fifteen years experience conducting consulting assignments relating to public utility economics and regulation. Exeter Associates, Inc. has served as Integrator for

Economic Studies with the Maryland Department of Natural Resources, and Mr. Kahal has directed that effort. In that capacity, he has supervised a team of senior level economists and engineers at Exeter and several subcontractors. He has also conducted consulting assignments for the U.S. Department of Energy, numerous state utility commissions, consumer advocacy agencies and private corporations.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR. He also developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College. As an Instructor at the University of Maryland, he taught courses on economic principles and economic development. As a Lecturer in business and economics at Montgomery College, Mr. Kahal developed and taught courses in macro and microeconomic principles, economic development and business.

Publications and Consulting Reports:

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

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A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

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An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum)

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

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Conference and Workshop Presentations:

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic impacts of proposed rate increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test year sales and revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test year sales, revenues, costs and load forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-use pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load forecasting, marginal cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for plant, load forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-use pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-use rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load forecasting, load management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of return, CWIP

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of return, capital structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of return
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of return, incentive *rates, rate base*
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of return, capital structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of return, rate phase-in plan

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of return
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co. regulation	Kentucky	Attorney General	Rate of return, incentive
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	NA	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et. al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of return
99.	90-256 January 1991	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
100.	U-17949A February 1991	South Central Bell Telephone Co.	Louisiana	Louisiana PSC	Rate of return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Co.	Maryland	Dept. of Natural Resources	Environmental controls
103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Co. Pennsylvania Electric Co.	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Co.	New Jersey	Rate Counsel	Rate of return
108.	91-5032 August 1991	Nevada Power Co.	Nevada	U.S. Dept. of Energy	Rate of return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of return
115.	GR910813931 March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of return
116.	P-870235 et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts
117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
128.	U-19904 November 1992 competition issues	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power supply clause
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power plant certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of return
137.	P-00930715 December 1993	Bell Telephone Co. of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of return, financial projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
139.	8583 February 1994	Conowingo Power Co.	Maryland	Dept. of Natural Resources	Competitive bidding for power supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Co.	Minnesota	Attorney General	Rate of return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of return

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
142.	92-345, Phase II June 1994	Central Maine Power Co.	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Co.	Nevada	Federal Executive Agencies	Rate of return
144.	94-0065 May 1994	Commonwealth Edison Co.	Illinois	Federal Executive Agencies	Rate of return
145.	GR94010002J June 1994	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of return
146.	WR94030059 July 1994	New Jersey-American Water Co.	New Jersey	Rate Counsel	Rate of return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Co.	Rate of return
149.	R-00942986 July 1994	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Rate of return, emission allowances
150.	94-121 August 1994	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger savings and allocations
152.	IPC-E-94-5 November 1994	Idaho Power Co.	Idaho	Federal Executive Agencies	Rate of return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of return (rebuttal only)
154.	90-256 December 1994	South Central Bell Telephone Co.	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of return Industrial contracts Trust fund earnings

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class cost of service issues
160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of capital spending program
163.	ER95-625-000 et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of return
164.	P-00950915 et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration contract amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital

Expert Testimony
of Matthew I. Kahal

171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues
175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

NOVEMBER 1997

EXETER
Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

DUQUESNE LIGHT COMPANY

OCA Overall Stranded Cost Summary
as of 12/31/98
(millions $)

Owned Generation[1]	$1,140.33
Regulatory Assets[2]	408.07
Transition Costs[2]	18.20
Total stand-alone[3]	$1,566.60
Total w/merger[3]	$1,414.32

(1) Source: Schedule MIK-1, page 3 of 3. This is stand-alone amount.

(2) Source: Schedule TSC-1. The Beaver Valley 2 lease, which is included on Mr. Catlin's regulatory asset schedule, is removed from the regulatory assets reported above and classified under owned-generation.

(3) 0.1 percent of total should be allocated to FERC jurisdiction.

DUQUESNE LIGHT COMPANY

Owned-Generation Stranded Cost Summary
Before Adjustments
(millions $)

Plant	Net Book Value @ 12/31/98	NPV Net Margins[1]	NPV Decommissioning Cost[3]	Stranded Cost
Perry	$232.34	$0	$18.93	$251.27
Beaver Valley 1	212.14	0	17.52	229.66
Beaver Valley 2[4]	545.84	0	8.02	553.86
Elrama	90.39	0	-	90.39
Cheswick	105.46	41.2[6]	-	64.26
Mansfield	94.81	129.6	-	(34.79)
Sammis	33.31	3.4	-	29.91
Eastlake	30.97	0	-	30.97
Brunot Island	17.06	0	-	17.06
Owned-Units Subtotal	$1,362.32	$180.1[2]	$44.47	$1,226.69
Working Capital	$61.53	$15.91		$45.62
Cold Reserve Plants[5]	$64.06	$0.00	-	$64.06
Total	**$1,487.91**	**$196.01**	**$44.47**	**$1,336.37**

(1) Excludes fossil decommissioning costs. Negative net margins are treated as zero.

(2) The total has been increased by 3.4 percent (a half-year of discounting) to account for the fact that Duquesne's cash flow model applies a full year discount in the first year.

(3) Source: Schedule TSC-2. Mr. Catlin's annual revenue requirement for 1999-2005 is converted to a NPV amount at 1/1/99 using a 6.88 percent discount rate.

(4) Beaver Valley 2 amount is the sum of reported net book value ($32.48 million) plus the NPV of the lease ($513.36 million). Source: Schedule TSC-1.

(5) This includes $3.48 million of remaining net book value for the Warwick mine at 12/31/98.

(6) This is based on post-2005 margins for Cheswick present valued back to 12/31/98. That is, it is assumed that Duquesne would not operate the plant at an operating loss during 1999-2005.

DUQUESNE LIGHT COMPANY

Owned-Generation Stranded
Cost Summary with Adjustments
(millions $)

Basic Model Results Before Adjustments:	$1,336.37[1]
Productivity Adjustment:	(25.32)[2]
Life Extension:	(170.72)[3]
Net Merger Savings:	(152.28)[4]
Net Stranded Cost w/o Merger	**$1,140.30**
Net Stranded Cost w/Merger	**$ 988.05**

[1] Source: Schedule MIK-1, page 2 of 3.
[2] Source: Schedule MIK-6, page 1 of 1.
[3] Source: Schedule MIK-8, page 7 of 7. Based on $300 per kW cost assumption.
[4] Source: Schedule MIK-9, page 1 of 1.

DUQUESNE LIGHT COMPANY

Excess Pre-Tax Earnings
During Transition Period
($ million)

	Beaver Valley Lease Amortization	Accelerated Depreciation	ROE @ 10%*	Total
1999	$25.0	$2.3	$22.6	$49.9
2000	25.0	2.2	21.6	48.8
2001	25.0	17.8	20.6	63.4
2002	25.0	68.8	19.3	113.1
2003	25.0	51.2	18.2	94.4
2004	25.0	62.0	17.4	104.4
2005	25.0	55.0	16.3	96.3
Total	$175.0	$259.3	$136.0	$570.3

*Reduction in the rate of return on equity target from 11.5 to 10.0 percent.

Source: Exhibit___(DLC-3), page 3 of 67, October 1997 update. Response to OCA 3-27, page 2 of 2 (updated).

DUQUESNE LIGHT COMPANY

Retail Rate Comparisons for 1996
(cents per kWh)

	Residential	Commercial	Industrial
Duquesne Light Co.	12.17¢	8.28¢	5.77¢
Metropolitan Edison Co.	8.83	7.86	6.03
Pennsylvania Electric Co.	8.72	7.48	5.45
Pennsylvania Power Co.	9.44	7.72	4.82
Pennsylvania Power & Light Co.	8.47	7.84	5.54
PECO Energy	12.84	11.53	7.22
West Penn Power Co.	6.80	5.86	4.45
Industry Average	8.64¢	7.63¢	4.46¢

Source: Regulatory Research Associates.

DUQUESNE LIGHT COMPANY

Residential Typical Monthly Bill Comparisons
Summer 1996

	500 kWh per Month	1,000 kWh per Month
Duquesne Light Co.	$62.80	$119.22
Metropolitan Edison Co.	48.28	89.88
Pennsylvania Electric Co.	45.89	84.98
Pennsylvania Power Co.	60.55	84.92
Pennsylvania Power & Light	47.55	85.49
PECO Energy	70.17	144.53
West Penn Power Co.	36.18	67.35
National Average	$46.37	$87.97

Source: Edison Electric Institute, Typical Residential, Commercial and Industrial Bills, Summer 1996.

DUQUESNE POWER COMPANY

DRI vs. Duquesne Inflation Rate Forecasts[1]

Year	DRI	Duquesne[3]
1997	1.90%	2.4%
1998	2.36	2.5
1999	2.49	2.5
2000	2.62	2.5
2001	2.92	2.6
2002	2.83	2.6
2003	3.01	2.7
2004	3.26	2.7
2005	3.32	2.7
2006	3.53	2.7
2007	3.48	2.6
2008	3.58	2.6
2009	3.60	2.7
2010	3.54	2.7
2011	3.55	2.7
2012	3.56	2.7
2013	3.56	2.7
2014	3.56	2.7
2015	3.61[2]	2.7

(1) Annual rates of increase in the U.S. GDP Deflator, Data Resources, Inc., Spring 1997 Forecast.

(2) Post 2015, it is assumed that inflation continues at 3.61 percent.

(3) Source: Exhibit MGK-4.

DUQUESNE LIGHT COMPANY

Derivation of the Discount Rate[1]

Capital Type	Balance[2] (000$)	% of Total	Cost Rate	Weighted Cost	Net of Tax Weighted Cost[4]
Long-term Debt	$1,325,876	51.88%	7.57%[3]	3.93%	2.30%
Preferred/Preference	239,330	9.37	7.45	0.70	0.70
Common Equity	990,236	38.75	10.0	3.88	3.88
Total	$2,555,442	100%	--	8.51%	6.88%

(1) Source: Item No. H-1, page 2 of 2 and 2-3, page 1 of 1, in Company Filing Requirements.

(2) Computed based on restoring $85,114,000 of unamortized debt reacquisition costs to the long-term debt balance. Duquesne had subtracted this amount from debt balance for capital structure purposes.

(3) Calculated as:

Interest expense	$105,126,200
+ Commitment fees	135,000
- Debt reacquisition amortization (1997)	4,944,045
	$100,317,155

Cost of debt = $100,317, 155/$1,325,876,000 = 7.57 percent
Source: Items H-2, page 6 of 6 and OCA I-8.

(4) Based on an effective income tax rate of 41.4935%.

DUQUESNE LIGHT COMPANY

Productivity Enhancement Savings[1]
($ millions)

Year	O&M	A&G	Total	Productivity Adjustment Factor[2]	Savings	Present Value Savings @ 6.88 %
1999	$61.70	$31.25	$92.95	--	--	--
2000	50.84	33.20	84.05	--	--	--
2001	54.10	36.11	90.21	--	--	--
2002	55.08	36.84	91.92	--	--	--
2003	58.41	38.35	96.75	0.0100	$0.97	$0.72
2004	55.15	44.32	99.47	0.0201	2.00	1.39
2005	62.41	41.62	104.03	0.0303	3.15	2.05
2006	59.89	43.86	103.75	0.0406	4.21	2.56
2007	64.02	47.75	111.78	0.0510	5.70	3.24
2008	65.92	48.26	114.18	0.0615	7.02	3.73
2009	69.99	50.56	120.55	0.0721	8.70	4.32
2010	64.31	56.32	120.63	0.0829	9.99	4.65
2011	68.50	47.58	116.08	0.0937	10.88	4.73
2012	62.14	41.97	104.11	0.1046	10.89	4.44
2013	64.21	44.75	108.96	0.1046	11.40	4.34
2014	65.68	45.69	111.37	0.1046	11.65	4.15
2015	14.32	23.77	38.09	0.1046	3.99	1.33
2016	4.98	11.06	16.04	0.1046	1.68	0.52
2017	3.20	8.81	12.01	0.1046	1.26	0.37
2018	3.66	9.81	13.47	0.1046	1.41	0.39
2019	3.77	9.60	13.37	0.1046	1.40	0.36
Totals	$1,012.29	$751.47	$1,763.76	--	$96.30	$43.28
Total (net of tax)						**$25.32**

[1]Excludes costs associated with Perry 1, Beaver Valley 1 and Elrama.
[2]Assumes a productivity or cost savings gain of 1.0 percent per year beginning in 2003 for ten years.

DUQUESNE POWER COMPANY

PECO and West Penn Power Life-Extension
Costs for Coal Plants

PECO Units[1]	Cost in 1997 $ (000s)	Unit Size (mW)	Cost per kW 1997$
Conemaugh	$75,000	352	$213
Keystone	$75,000	357	$210
Eddystone 2	$51,000	302	$169
West Penn Units[2]			
Mitchell 3	$30,169	284	$106
Armstrong 1, 2	$54,454	352	$155

(1) Source: Exhibit TPH-3, page 4, PaPUC Docket No. R-00973953 (PECO restructuring case).

(2) Source: Exhibit WEC-1 and WEC-2 in PaPUC Docket No. R-00973981. All figures are in actual year dollars.

DUQUESNE LIGHT COMPANY

Cheswick Life Extension Costs and Net Benefits
($000s)

Year	Life Extension Capital Cost[1]	Non-Fuel O&M Expenses[2]	Fuel Costs[3]	Market Revenues[3]	Net Benefits[4]	PV Factor @ 6.88 %	1999 NPV Net Benefits
2014	$195,419				$(195,419)	0.3565	$(69,674)
2015	0	62,573	107,238	214,658	44,847	0.3336	14,960
2016	0	64,832	111,109	222,407	46,466	0.3121	14,503
2017	0	67,173	115,120	230,436	48,143	0.2920	14,059
2018	0	69,598	119,276	238,755	49,881	0.2732	13,629
2019	0	72,110	123,582	247,374	51,682	0.2556	13,212
2020	0	74,713	128,043	256,304	53,547	0.2392	12,808
2021	0	77,410	132,666	265,557	55,481	0.2238	12,416
2022	0	80,205	137,455	275,143	57,483	0.2094	12,036
2023	0	83,100	142,417	285,076	59,559	0.1959	11,668
2024	0	86,100	147,558	295,367	61,709	0.1833	11,311
2025	0	89,208	152,885	306,030	63,936	0.1715	10,965
2026	0	92,429	158,404	317,078	66,244	0.1605	10,629
2027	0	95,766	164,123	328,524	68,636	0.1501	10,304
2028	0	99,223	170,048	340,384	71,114	0.1405	9,989
2029	0	102,805	176,186	352,672	73,681	0.1314	9,683
Total							**$112,495**

(1) Based on $200 per kW in 1997$ escalated to year of retirement at DRI inflation rates.

(2) Based on non-fuel plant expenses (fixed O&M, A&G, taxes other than income, capital additions) averaged over the five years prior to book retirement. The five-year average was inflation adjusted to the first year of life extension and escalated at 3.61 percent thereafter.

(3) Includes both fuel and non-fuel variable O&M as supplied by OCA witness Doug Smith. Based on cost or revenue per kWh in initial year of life extension. Generation output based on a five-year average. Figures escalated at 3.61 percent after first year.

(4) Market revenue minus the sum of fuel cost, non-fuel O&M and life extension cost.

DUQUESNE LIGHT COMPANY

Sammis Life Extension Costs and Net Benefits
($000s)

Year	Life Extension Capital Cost[1]	Non-Fuel O&M Expenses[2]	Fuel Costs[3]	Market Revenues[3]	Net Benefits[4]	PV Factor @ 6.88 %	1999 NPV Net Benefits
2011	$55,733				$(55,733)	0.4353	$(24,261)
2012	0	17,393	26,922	61,352	17,037	0.4073	6,939
2013	0	18,021	27,894	63,567	17,652	0.3811	6,726
2014	0	18,672	28,901	65,862	18,289	0.3565	6,521
2015	0	19,346	29,944	68,239	18,949	0.3336	6,321
2016	0	20,044	31,025	70,703	19,633	0.3121	6,128
2017	0	20,768	32,145	73,255	20,342	0.2920	5,940
2018	0	21,518	33,306	75,899	21,076	0.2732	5,759
2019	0	22,294	34,508	78,639	21,837	0.2556	5,582
2020	0	23,099	35,754	81,478	22,625	0.2392	5,412
2021	0	23,933	37,044	84,420	23,442	0.2238	5,246
2022	0	24,797	38,382	87,467	24,288	0.2094	5,086
2023	0	25,692	39,767	90,625	25,165	0.1959	4,930
2024	0	26,620	41,203	93,896	26,074	0.1833	4,779
2025	0	27,581	42,690	97,286	27,015	0.1715	4,633
2026	0	28,576	44,231	100,798	27,990	0.1605	4,491
Total							**$60,231**

(1) Based on $200 per kW in 1997$ escalated to year of retirement at DRI inflation rates.

(2) Based on non-fuel plant expenses (fixed O&M, A&G, taxes other than income, capital additions) averaged over the five years prior to book retirement. The five-year average was inflation adjusted to the first year of life extension and escalated at 3.61 percent thereafter.

(3) Includes both fuel and non-fuel variable O&M as supplied by OCA witness Doug Smith. Based on cost or revenue per kWh in initial year of life extension. Generation output based on a five-year average. Figures escalated at 3.61 percent after first year.

(4) Market revenue minus the sum of fuel cost, non-fuel O&M and life extension cost.

DUQUESNE LIGHT COMPANY

Eastlake Life Extension Costs and Net Benefits
($000s)

Year	Life Extension Capital Cost[1]	Non-Fuel O&M Expenses[2]	Fuel Costs[3]	Market Revenues[3]	Net Benefits[4]	PV Factor @ 6.88 %	1999 NPV Net Benefits
2012	$57,414				$(57,414)	0.4073	$(23,384)
2013	0	16,861	23,865	47,420	6,694	0.3811	2,551
2014	0	17,470	24,727	49,132	6,935	0.3565	2,473
2015	0	18,101	25,619	50,906	7,186	0.3336	2,397
2016	0	18,754	26,544	52,743	7,445	0.3121	2,324
2017	0	19,431	27,502	54,647	7,714	0.2920	2,253
2018	0	20,133	28,495	56,620	7,992	0.2732	2,184
2019	0	20,859	29,524	58,664	8,281	0.2556	2,117
2020	0	21,612	30,590	60,782	8,580	0.2392	2,052
2021	0	22,393	31,694	62,976	8,889	0.2238	1,989
2022	0	23,201	32,838	65,249	9,210	0.2094	1,928
2023	0	24,039	34,023	67,605	9,543	0.1959	1,869
2024	0	24,906	35,252	70,045	9,887	0.1833	1,812
2025	0	25,806	36,524	72,574	10,244	0.1715	1,757
2026	0	26,737	37,843	75,194	10,614	0.1605	1,703
2027	0	27,702	39,209	77,909	10,997	0.1501	1,651
Total							**$7,676**

(1) Based on $200 per kW in 1997$ escalated to year of retirement at DRI inflation rates.

(2) Based on non-fuel plant expenses (fixed O&M, A&G, taxes other than income, capital additions) averaged over the five years prior to book retirement. The five-year average was inflation adjusted to the first year of life extension and escalated at 3.61 percent thereafter.

(3) Includes both fuel and non-fuel variable O&M as supplied by OCA witness Doug Smith. Based on cost or revenue per kWh in initial year of life extension. Generation output based on a five-year average. Figures escalated at 3.61 percent after first year.

(4) Market revenue minus the sum of fuel cost, non-fuel O&M and life extension cost.

DUQUESNE LIGHT COMPANY

Mansfield Unit 1 Life Extension Costs and Net Benefits
($000s)

Year	Life Extension Capital Cost[1]	Non-Fuel O&M Expenses[2]	Fuel Costs[3]	Market Revenues[3]	Net Benefits[4]	PV Factor @ 6.88 %	1999 NPV Net Benefits
2015	$80,986				$(80,986)	0.3336	$(27,016)
2016	0	19,670	17,194	44,686	7,822	0.3121	2,441
2017	0	20,380	17,815	46,299	8,104	0.2920	2,367
2018	0	21,116	18,458	47,971	8,397	0.2732	2,294
2019	0	21,878	19,124	49,702	8,700	0.2556	2,224
2020	0	22,668	19,815	51,497	9,014	0.2392	2,156
2021	0	23,486	20,530	53,356	9,339	0.2238	2,090
2022	0	24,334	21,271	55,282	9,676	0.2094	2,026
2023	0	25,213	22,039	57,277	10,026	0.1959	1,964
2024	0	26,123	22,834	59,345	10,388	0.1833	1,904
2025	0	27,066	23,659	61,487	10,763	0.1715	1,846
2026	0	28,043	24,513	63,707	11,151	0.1605	1,789
2027	0	29,055	25,398	66,007	11,554	0.1501	1,735
2028	0	30,104	26,315	68,390	11,971	0.1405	1,681
2029	0	31,191	27,265	70,859	12,403	0.1314	1,630
2030	0	32,317	28,249	73,417	12,851	0.1230	1,580
Total							**$2,711**

(1) Based on $200 per kW in 1997$ escalated to year of retirement at DRI inflation rates.

(2) Based on non-fuel plant expenses (fixed O&M, A&G, taxes other than income, capital additions) averaged over the five years prior to book retirement. The five-year average was inflation adjusted to the first year of life extension and escalated at 3.61 percent thereafter.

(3) Includes both fuel and non-fuel variable O&M as supplied by OCA witness Doug Smith. Based on cost or revenue per kWh in initial year of life extension. Generation output based on a five-year average. Figures escalated at 3.61 percent after first year.

(4) Market revenue minus the sum of fuel cost, non-fuel O&M and life extension cost.

DUQUESNE LIGHT COMPANY

Mansfield Unit 2 Life Extension Costs and Net Benefits
($000s)

Year	Life Extension Capital Cost[1]	Non-Fuel O&M Expenses[2]	Fuel Costs[3]	Market Revenues[3]	Net Benefits[4]	PV Factor @ 6.88 %	1999 NPV Net Benefits
2016	$22,818				$(22,818)	0.3121	$(7,122)
2017	0	5,527	10,032	26,012	10,453	0.2920	3,053
2018	0	5,726	10,394	26,951	10,830	0.2732	2,959
2019	0	5,933	10,769	27,924	11,221	0.2556	2,869
2020	0	6,147	11,158	28,932	11,627	0.2392	2,781
2021	0	6,369	11,561	29,976	12,046	0.2238	2,696
2022	0	6,599	11,978	31,059	12,481	0.2094	2,613
2023	0	6,837	12,411	32,180	12,932	0.1959	2,533
2024	0	7,084	12,859	33,342	13,399	0.1833	2,456
2025	0	7,340	13,323	34,545	13,882	0.1715	2,381
2026	0	7,605	13,804	35,792	14,383	0.1605	2,308
2027	0	7,879	14,302	37,084	14,903	0.1501	2,237
2028	0	8,164	14,819	38,423	15,441	0.1405	2,169
2029	0	8,459	15,354	39,810	15,998	0.1314	2,102
2030	0	8,764	15,908	41,247	16,576	0.1230	2,038
2031	0	9,080	16,482	42,736	17,174	0.1150	1,976
Total							**$30,048**

(1) Based on $200 per kW in 1997$ escalated to year of retirement at DRI inflation rates.

(2) Based on non-fuel plant expenses (fixed O&M, A&G, taxes other than income, capital additions) averaged over the five years prior to book retirement. The five-year average was inflation adjusted to the first year of life extension and escalated at 3.61 percent thereafter.

(3) Includes both fuel and non-fuel variable O&M as supplied by OCA witness Doug Smith. Based on cost or revenue per kWh in initial year of life extension. Generation output based on a five-year average. Figures escalated at 3.61 percent after first year.

(4) Market revenue minus the sum of fuel cost, non-fuel O&M and life extension cost.

DUQUESNE LIGHT COMPANY

Mansfield Unit 3 Life Extension Costs and Net Benefits
($000s)

Year	Life Extension Capital Cost[1]	Non-Fuel Expenses[2]	Fuel Costs[3]	Market Revenues[3]	Net Benefits[4]	PV Factor @ 6.88 %	1999 NPV Net Benefits
2019	$45,027				$(45,027)	0.2556	$(11,511)
2020	0	10,852	41,646	106,340	53,842	0.2392	12,878
2021	0	11,243	43,149	110,179	55,786	0.2238	12,484
2022	0	11,649	44,707	114,156	57,800	0.2094	12,102
2023	0	12,070	46,321	118,277	59,886	0.1959	11,732
2024	0	12,506	47,993	122,547	62,048	0.1833	11,373
2025	0	12,957	49,726	126,971	64,288	0.1715	11,025
2026	0	13,425	51,521	131,555	66,609	0.1605	10,688
2027	0	13,909	53,381	136,304	69,014	0.1501	10,361
2028	0	14,412	55,308	141,224	71,505	0.1405	10,044
2029	0	14,932	57,304	146,323	74,086	0.1314	9,736
2030	0	15,471	59,373	151,605	76,761	0.1230	9,438
2031	0	16,029	61,517	157,078	79,532	0.1150	9,150
2032	0	16,608	63,737	162,748	82,403	0.1076	8,870
2033	0	17,208	66,038	168,624	85,378	0.1007	8,598
2034	0	17,829	68,422	174,711	88,460	0.0942	8,335
Total							**$145,303**

(1) Based on $200 per kW in 1997$ escalated to year of retirement at DRI inflation rates.

(2) Based on non-fuel plant expenses (fixed O&M, A&G, taxes other than income, capital additions) averaged over the five years prior to book retirement. The five-year average was inflation adjusted to the first year of life extension and escalated at 3.61 percent thereafter.

(3) Includes both fuel and non-fuel variable O&M as supplied by OCA witness Doug Smith. Based on cost or revenue per kWh in initial year of life extension. Generation output based on a five-year average. Figures escalated at 3.61 percent after first year.

(4) Market revenue minus the sum of fuel cost, non-fuel O&M and life extension cost.

DUQUESNE LIGHT COMPANY

Power Plant Life Extension Summary[1]
(millions $ 1/1/99 NPV)

Plant	Net Benefit @ $200 kW	Net Benefit @ $300 kW
Cheswick	$112.50	$77.66
Sammis	60.23	48.10
Eastlake	7.68	(4.02)
Mansfield 1	2.71	(10.80)
Mansfield 2	30.05	26.49
Mansfield 3	145.30	139.55
Total	**$358.47**	**$291.80[2]**
Total (net of tax)	**$209.73**	**$170.72[2]**

(1) Based upon a 6.88 percent discount rate.

(2) Negative values are set to zero. That is, it is assumed that life extension would not occur at $300 per kW if market revenue was insufficient to warrant the investment.

DUQUESNE LIGHT COMPANY

Generation Net Merger Savings
($000)

Year	Duquesne Net Merger Savings[1]	Dispatch[2]	Merger Savings Net of Dispatch	Generation Savings w/o Dispatch	Generation Savings w/Dispatch	PV Factor @ 6.88%	PV Net of Tax Savings
1999	$29,884	$2,500	$27,384	$13,237	$15,737	0.9673	$8,906
2000	31,653	2,568	29,153	14,093	16,660	0.9050	8,227
2001	34,119	2,637	31,619	15,285	17,921	0.8468	8,879
2002	36,222	2,708	33,722	16,301	19,009	0.7923	8,812
2003	37,994	2,781	35,494	17,158	19,939	0.7413	8,648
2004	36,145	2,856	33,645	16,264	19,120	0.6935	7,758
2005	38,361	2,933	35,861	17,335	20,269	0.6489	7,695
2006	46,720	3,013	44,220	21,376	24,388	0.6071	8,663
2007	49,130	3,094	46,630	22,541	25,635	0.5680	8,519
2008	50,457	3,177	47,889	23,150	26,404	0.5315	8,211
2009	51,819	3,263	49,182	23,775	27,196	0.4973	7,913
2010	53,218	3,351	50,510	24,416	28,012	0.4653	7,478
2011	54,655	3,442	51,874	25,076	28,852	0.4353	7,348
2012	56,131	3,535	53,274	25,753	29,718	0.4073	7,082
2013	57,646	3,630	54,713	26,448	30,609	0.3811	6,825
2014	59,202	3,728	56,190	27,162	31,528	0.3565	6,576
2015	60,801	3,829	57,707	27,896	32,473	0.3353	6,370
2016	62,443	3,932	59,265	28,649	33,448	0.3121	6,108
2017	64,129	4,038	60,865	29,422	34,451	0.2920	5,886
2018	65,860	4,147	62,509	30,217	35,485	0.2732	5,672
Totals					**$516,855**		**$152,280**

(1)Source: Exhibit MKO-2 in Docket No. A110150.
(2)Escalated at 2.7 percent.
(3)Duquesne net savings minus $2,500 through 2007. Escalated at 2.7 percent thereafter.
(4)Generation net savings equal to 48.34 percent of total net savings (excluding dispatch).

OCA Statement No. 1S

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

SURREBUTTAL TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

DECEMBER 1997

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

SURREBUTTAL TESTIMONY OF MATTHEW I. KAHAL

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. My business address is 12510 Prosperity Drive, Silver Spring, Maryland 20904. I am a Senior Economist and Principal at Exeter Associates, Inc., a consulting firm specializing in public utility regulation and energy studies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes. In November, I submitted direct testimony on behalf of the Office of Consumer Advocate (OCA) addressing the stranded costs and the plan for recovery of those costs of Duquesne Light Company (DLC or the Company).

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. On December 2, 1997, Duquesne Light Company (DLC or the Company) filed rebuttal testimony responding to the direct testimony of the parties, including the OCA. My surrebuttal testimony replies to that testimony addressing issues concerning stranded cost estimation and aspects of stranded cost recovery.

Q. AFTER REVIEWING DUQUESNE'S REBUTTAL TESTIMONY, ARE YOU MAKING ANY MODIFICATIONS TO YOUR STRANDED COST ESTIMATE?

A. Yes. I have provided an update to Schedule MIK-1 which summarizes the OCA's stranded cost presentation. Page 1 of that schedule indicates stranded cost of $1,659.6 million, or $1,507.3 if the merger with Allegheny Energy is completed. This is an increase of $93 million compared to my original testimony. The entire increase is related to owned-generation. There are no changes to either the regulatory assets or the transition costs sponsored by OCA witness Catlin. The reasons for the update are described later in my surrebuttal testimony.

Q. BEFORE TURNING TO THE REBUTTAL FILING, PLEASE SUMMARIZE DUQUESNE'S ORIGINAL STRANDED COST RECOVERY PLAN.

A. The Duquesne plan is based on keeping in place the capped generation rates over the entire seven-year transition period.[1] The transition charges would be based on the difference between the capped generation rates and actual market prices, with the latter to be determined by Duquesne's annual auctions. Duquesne proposes to recover its stranded costs (i.e., generation investments) through a schedule of accelerated depreciation/amortization over the seven years. That schedule or minimum commitment is calibrated using the Company's financial projections so as to provide a return on equity of 11.5 percent.

Mr. Clayton conducted a stranded cost projections study as of 12/31/2005 intended to "test" whether this approach will overcollect stranded cost. He concluded that it probably would not. However, in light of the uncertainty associated with any study conducted at this time, Duquesne proposes a final valuation be initiated in 2003.

[1]There is one notable exception. Duquesne proposes a rate increase of 1.9 mills per kWh to incorporate the ECR ceiling (14.7 mills per kWh compared to the rolled in 12.8 mills per kWh) under the 1996 Ft. Martin settlement.

Depending on the outcome, the rate cap and stranded cost recovery could be terminated early, maintained through 2005 or extended beyond 2005.

In mid-October, Duquesne filed an extensive update of its cost projections. This resulted in changes to the schedule of accelerated depreciation/amortization and the 12/31/2005 stranded cost estimate, but Duquesne did not recommend any changes to the broad outlines of its stranded cost recovery plan.

Q. HOW HAVE DUQUESNE WITNESSES ADDRESSED STRANDED COST RECOVERY IN THE DECEMBER 2, 1997 REBUTTAL FILING?

A. The rebuttal filing introduces some changes to the stranded cost recovery plan along with extensive new information concerning the estimation of stranded cost. The major changes and new information include the following:

- Duquesne suggests a divestiture of its generation assets in 2003 as a market-based method for resolving stranded costs.

- Duquesne is willing to make modifications to its RFP auction approach which is intended to establish the market prices during the transition period.

- The rebuttal testimony recognizes that continued operation of, and investment in, its uneconomic units may be problematic. The Company therefore proposes to file a plant shutdown study with the Commission by the end of 1998 recommending a course of action to mitigate the stranded costs associated with potentially uneconomic operations.

In addition to the policy proposals, Duquesne's filing introduces the following new information.

- Mr. Clayton's rebuttal testimony provides, <u>for the first time</u>, an analysis of the net present value of the Company's stranded costs at December 31, 1998, i.e., the start of the transition period. The only evidence he previously presented on stranded costs (in both the original filing and the mid-October update) related to the balance of such costs as of December 31, 2005 -- the end of the transition period.

- Mr. Clayton's rebuttal testimony introduces <u>for the first time</u> a new theory concerning how stranded cost should be quantified, regardless of when the quantification takes place. According to this new theory, the stranded costs of a unit can exceed the net book value of the unit plus decommissioning costs. In cases where a unit provides no market revenue in excess of its ongoing costs, the stranded cost calculation (according to this theory) must also include various other alleged

costs. In other words, according to Mr. Clayton's rebuttal, stranded cost quantification should incorporate negative market values for generating units.

The Stranded Cost Recovery Plan

Q. WHAT WERE YOUR MAIN REASONS FOR OPPOSING DUQUESNE'S ORIGINAL PLAN?

A. I criticized the originally filed Duquesne plan on a number of grounds.

- The plan provides no rate relief from Duquesne's very high rates (12.2 cents per kWh for residential customers) until after 2005 (except for the merger-related reduction in 2001). This is the most serious defect in that plan.

- It is the purpose of this proceeding to establish stranded costs and their recovery. It should not be deferred to a final valuation six years from now.

- The auction method may understate market prices, but in any event it fails to establish transition charge amounts within this proceeding.

- The justification for the "capped rate" plan is that all excess earnings will be returned to customers in the form of accelerated amortization. I questioned whether the "ROE spillover" mechanism is workable given that Duquesne will be partially deregulated.

- As a factual matter, Mr. Clayton's 12/31/2005 stranded cost analysis did not convincingly pass his own test.

For all of these reasons, I recommended rejection of the Duquesne's plan.

Q. DO THE PLAN MODIFICATIONS AND NEW INFORMATION ALTER YOUR OPINION REGARDING THE MERITS OF THE PLAN?

A. No. While Duquesne is showing some flexibility concerning its stranded cost recovery plan in rebuttal testimony, the principal defects remain. These include: no rate decrease for retail customers for many years; a flawed "ROE spillover" mechanism; and deferring for many years the resolution of stranded cost quanification.

Q. MR. MARSHALL RAISES GENERATION DIVESTITURE AS AN OPTION. IS THIS A REASONABLE APPROACH?

A. I interpret Mr. Marshall's testimony as stating that Duquesne would be willing to proceed with a divestiture if directed to do so by the Commission rather than being an affirmative

proposal to divest generation. Furthermore, Mr. Marshall insists that any such divestiture be deferred until at least 2003 due to the Company's obligation to provide generation service during the divestiture.

Although Mr. Marshall's apparent acceptance of generation divestiture is constructive, the specific plan that he proposes retains the shortcomings which I discussed. Specifically, the divestiture plan seems to rule out any rate relief for retail customers for six years or longer, and it similarly delays the quantification of stranded cost. All it accomplishes is the substitution of a market auction for the proposed arbitration panel mechanism in 2003. While divestiture in concept has merit, Duquesne's rebuttal filing does not propose an acceptable plan.

Q. MR. MARSHALL INSISTS THAT A DIVESTITURE CANNOT TAKE PLACE BEFORE 2003 DUE TO THE OBLIGATION TO SERVE PROBLEM. DO YOU AGREE?

A. This is an issue which would require further study and discussion among the parties. I would note that a similar issue exists for the Rhode Island and Massachusetts utilities which are conducting generation divestiture and which retain an obligation to provide generation service during a transition period. Those utilities resolved that problem by transferring the temporary "backstop" service obligation (at predetermined generation prices) to the buyers of the assets. A transfer mechanism such as this could be explored for Duquesne, which would permit the divestiture to proceed prior to the introduction of customer choice on January 1, 1999.

Potentially, a divestiture in 1998 could overcome many of the objections to Duquesne's plan discussed in my testimony. Unfortunately, the limited time between the receipt of rebuttal and the filing of surrebuttal does not leave sufficient time to develop a workable divestiture plan.

Q. SUPPOSE THAT DUQUESNE IS ABLE TO PROCEED WITH A DIVESTITURE IN 1998. WOULD THAT SET ASIDE THE ISSUE OF STRANDED COST SHARING?

A. No, it would not. Divestiture may provide a more accurate quantification of stranded cost and thereby eliminate considerable controversy over such issues. It does not in anyway eliminate the need for an appropriate sharing of stranded costs between ratepayers and shareholders.

Q. DUQUESNE'S REBUTTAL TESTIMONY CONTINUES TO DEFEND THE CAPPED RATE PLAN FOR RECOVERY OF STRANDED COST. DOES THE INFORMATION IN THE REBUTTAL FILING DEMONSTRATE WHY MAINTAINING CAPPED RATES IS APPROPRIATE?

A. No. The information which has become available on rebuttal convincingly demonstrates why that plan cannot be accepted. Duquesne's argument for retaining its capped rates relies upon the legal argument that it has a right to those capped rates as long as any excess earnings will be used to eliminate stranded costs. The "ROE spillover" mechanism is intended to do just that, thereby satisfying the legal condition. Thus, the validity of the ROE spillover is key to the integrity of Duquesne's plan.

My direct testimony criticized the "ROE spillover" on several grounds. First, the threshold for allocating earnings of 11.5 percent is far too high and exceeds the Company's fair return. Second, the Company has not proposed any sort of a reasonable or workable process for determining what its earnings would be on a regulatory basis. Moreover, measuring Duquesne's regulated earnings may prove to be a practical impossibility during the transition period when Duquesne has one foot in the competitive market for power supply. The risk is that ratepayers might end up subsidizing

unregulated operations through the ROE spillover. Third, there may be issues of prudence if Duquesne insists on operating uneconomic generating units.

The rebuttal filing provides additional information which helps to explain, but not resolve, this last issue of operating losses. Mr. Clayton's financial projections support accelerated depreciation/amortization of $1.8 billion (at an 11.5 percent ROE). However, based on his new stranded cost study, we now have information on the magnitude of those losses. I have constructed Schedule MIK-10 which documents the operating losses each year for each Duquesne power plant, excluding those plants which the Company claims have a positive market value (i.e., Mansfield and Beaver Valley 1). The operating losses are on the order of $100 million per year, or $690 million for the transition period. Arguably, it may be imprudent for Duquesne to incur all of these losses.

Q. HAS THE COMPANY ATTEMPTED TO ADDRESS THESE PROBLEMS?

A. In part. Dr. Makholm attempts to defend the 11.5 percent return on equity.[2] Mr. Clayton and other Duquesne witnesses attempt to provide cost data in their rebuttal demonstrating that at least some of these operating losses are unavoidable and therefore may not represent imprudence.

The problem is that there is no real opportunity to investigate these allegedly avoidable operating costs associated with the uneconomic generating units since this information was introduced for the first time in rebuttal testimony. Moreover, Duquesne itself seems very unsure as to how much of the projected losses are prudently incurred costs and how much could be avoided. As explained by Mr. Marshall, Duquesne proposes to conduct a shut down study during 1998 to make that determination because it does not know at this time the amount of savings available from shutdown.

[2]Dr. Makholm's rebuttal provides no real explanation concerning why this Commission's 10.0 percent ROE finding for PECO should not apply to Duquesne.

Q. WHAT IS YOUR OBJECTION TO A SHUTDOWN STUDY?

A. My objection is primarily one of timing. The information on operating losses on my Schedule MIK-10 is not new. Aside from the October update revisions to cost data, the existence of these operating losses and the economic viability of its generating units was known to Duquesne well before it filed its case on August, 1 1997. Duquesne made a conscious and deliberate decision not to address this problem and not to reveal the operating losses, instead burying the losses within its financial projections.

After the issue of unnecessary operating losses was raised by the OCA (and others), Duquesne then proceeded to introduce in rebuttal cost data indicating that some of the operating losses may be unavoidable when there is no realistic opportunity to analyze and study those data. Moreover, conceding that some of the losses may be avoidable, Duquesne agrees to study the issue after this proceeding is over. Since avoidance of operating losses is an issue of mitigation, I believe that Duquesne has an obligation to address the issue in this proceeding, not study it at some future time. The lack of clear evidence on this issue is one reason why the rate cap plan cannot be accepted.

Q. ARE THERE ANY OTHER ISSUES CONCERNING THE STRANDED COST RECOVERY PLAN WHICH YOU WOULD LIKE TO ADDRESS?

A. Yes. I believe implicit in the Company's plan is the assumption that it has a right to 100 percent recovery of and return on its owned generation stranded costs.[3] Pennsylvania's statute does not specify 100 percent stranded cost recovery but a "just and reasonable" level of recovery. Certainly, one should be mindful of Pennsylvania's past policy on cost recovery for "uneconomic" generating capacity under standard regulation.

[3]To be fair, Duquesne's plan (which includes a minimum accelerated depreciation) provides, in concept, an opportunity for 100 percent cost recovery but not a guarantee. Thus, there is some risk. It is accurate, however, to observe that the plan does not explicitly provide for sharing.

The information developed in this case, by both the OCA and the Company, demonstrates very clearly just how uneconomic the Company's generating capacity is. This is not a matter of using some new standard or measuring stick for "economic excess capacity." Rather, the revenue requirements for Duquesne's nuclear power plants enormously exceed the cost of all reasonable alternatives and the benefits those plants provide to customers.

It seems clear that if standard ratemaking were to continue, some sharing of the excess cost burden would be required. If anything, the transition to competition heightens the need for sharing.

Q. IS THE OCA'S SHARING FORMULA UNREASONABLE?

A. No, I don't believe so. As Mr. Clayton points out, the denial of return approach to sharing means that shareholders absorb about one-third of the stranded cost revenue requirements associated with owned generation. Since owned-generation is about two-thirds of the stranded cost total, this means that ratepayers effectively absorb about 75 percent of total stranded cost. Thus, the end result of the OCA's approach is a 75 percent ratepayer/25 percent shareholder split of the total stranded cost. I do not consider this to be unreasonable or punitive to the Company.

It should also be noted that although the Company is denied an explicit return, it is permitted to recover its uneconomic nuclear investments within seven years. This is considerably shorter than the remaining 30 years over which recovery of the costs for units such as Perry and Beaver Valley 2 would occur under standard regulation.

Stranded Cost Quantification

Q. HAS THE COMPANY SUBMITTED A NEW STRANDED COST STUDY?

A. Yes. For the first time in this case, Duquesne has provided an estimate of its stranded costs at December 31, 1998. It appears that this study was prepared only for the purpose

of attacking the estimates of the other parties, not for purposes of setting competitive transition charges. Given the very short time between rebuttal and surrebuttal testimony, there is no realistic opportunity to conduct discovery and review the analysis in detail. Thus, a lack of detailed comments should not be interpreted as concurrence.

Q. DO THE RESULTS OF THIS STUDY APPEAR TO BE REASONABLE?

A. No, they are not. Mr. Clayton presents a summary of his new 12/31/98 stranded cost study on his Exhibit No. DJC-10. According to his study the net book value of the Company's generating plant is $1,237 million, and the owned-generation stranded cost is $1,542 million. It should be noted that the stranded cost figure is inclusive of about $57 million of unfunded nuclear decommissioning, and absent that amount, stranded cost would be about $1,485 million. Since stranded cost exceeds net book value, the implication is that Duquesne's entire portfolio of power supply assets has a negative market value of approximately $200 million. Moreover, the $200 million negative market value assumes that Duquesne retains the nuclear decommissioning obligation rather than the buyer of the assets. This implies that if Duquesne decided to sell its generation assets, it would have to pay a buyer over $200 million to take the assets, even if Duquesne retained the nuclear decommissioning obligation. This is not a plausible result and should not be accepted.

Q. WHAT ACCOUNTS FOR THIS VERY PESSIMISTIC RESULT?

A. There appear to be two main reasons. First, Mr. Clayton's analysis produces very little net operating revenue, i.e., only $27 million life time net present value for all units combined. By comparison, my analysis obtains approximately $300 million of net revenues, which I believe is a very modest result. Second, Mr. Clayton's study introduces for the first time the concept of operating losses as a separate stranded cost

component. This comes to over $200 million in Mr. Clayton's study. (He refers to this as "PV of Costs Independent of Operation.")

Q. WAS THERE ANY RECOGNITION OF THIS COST COMPONENT IN HIS ORIGINAL STUDY FILED WITH HIS DIRECT TESTIMONY OR OCTOBER 1997 UPDATE?

A. No. In his original study, negative market values (except for decommissioning) were set to zero. There was no discussion, analysis or presentation of "PV of Costs Independent of Operation." This is a basic change in methodology introduced for the first time in rebuttal.

Q. SHOULD THIS CHANGE IN METHODOLOGY BE ACCEPTED?

A. No, it should not. First, I do not believe stranded costs should be set on the basis of negative market values as Mr. Clayton proposes. I believe his original approach of setting market value equal to zero (except for nuclear decommissioning) is reasonable if a plant cannot provide any net operating margins. Second, there is not adequate time to investigate the factual basis for those new claims that Duquesne's plants have negative value.

Q. IS MR. CLAYTON'S STRANDED COST FINDING CONSISTENT WITH MARKET ASSET TRANSACTION SALES EXPERIENCE?

A. No, it is not. The best example is Duquesne's sale last year of its 50 percent ownership in the Ft. Martin 1 coal unit. Duquesne received proceeds of $169 million, which is about six times its net present value margins ($27 million) for all of its units combined.

Debt Reacquisition Costs

Q. MR. CLAYTON CRITICIZES YOUR TREATMENT OF DEBT REACQUISITION COSTS. WHAT IS HIS CONCERN?

A. Mr. Catlin provides Duquesne with dollar for dollar recovery of unamortized debt reacquisition costs (and related items), inclusive of a return on the unamortized balance. This recovery is provided as a regulatory asset over the seven-year transition period. By any definition, this is 100 percent recovery of those unamortized costs.

Mr. Clayton's complaint is that I removed debt reacquisition costs from rate of return (lowering the cost of debt and slightly altering capital structure). Given that Mr. Catlin allows recovery of debt reacquisition costs as a regulatory asset, it is necessary for me to remove it as a component of rate of return. Unless I do that, Duquesne will recover those costs twice. Thus, my removal from rate of return is merely a consistency adjustment.

Q. WHAT IS MR. CLAYTON'S CRITICISM?

A. Mr. Clayton objects because removal of the reacquisition costs from rate of return leads to a lower cost of debt (too low in his opinion) and too high of a debt ratio (too high in his opinion).[4] Significantly, Mr. Clayton does not allege a calculation error. Rather, with debt reacquisition costs removed, I am using the actual cost of debt in the rate of return calculation and Duquesne's actual capital structure. It is unclear why he finds my use of actuals to be objectionable. For example, if Duquesne believes its actual capital structure to have too much debt, management can add equity to reach the desired level.

Dr. Makholm observes that recovery of debt reacquisition costs within rate of return is a standard treatment, and I agree. My treatment is necessitated by the fact that this is a stranded cost study, not a standard rate case. Debt reacquisition costs are being afforded special cost recovery treatment as a regulatory asset.

[4]This occurs because Duquesne subtracts the unamortized balance of debt reacquisition costs from debt outstanding to compute its capital structure ratio. When Mr. Catlin provides regulatory asset recovery, it is necessary to reverse that adjustment.

Changes to Stranded Cost

Q. WHAT CHANGES HAVE YOU MADE TO YOUR ORIGINAL STRANDED COST STUDY?

A. I have made two changes to my stranded cost estimate. The first change relates to the Cheswick unit. In my direct testimony, I noted that the Cheswick plant was projected to incur large near-term operating losses but long-term net margins. The life extension analysis contributes to those margins. Thus, in order to mitigate the losses and maximize the economic value of the plant, I assumed that the near-term losses could be avoided. I indicated that one method of avoiding those losses could be through temporary shutdown. Alternatively, the losses could be avoided through cost control measures plus expanded sales. The near-term (i.e., 1999-2005) operating losses (pre-tax) for the Cheswick unit using OCA witness Douglas Smith's projections are substantial.

Q. WHY ARE THE LOSSES SO LARGE IN THE NEAR-TERM?

A. Mr. Smith's analysis obtains a very conservative level of sales during those initial seven years from the Cheswick unit, only about 13,600 GWh which is about half what Duquesne is projecting. If Cheswick was assumed to generate at the level assumed by Duquesne's model, the near-term operating loss which I cited would greatly diminish. That is why I stated in my direct testimony that the temporary shut down was only one potential means of avoiding the near-term operating losses.

Q. WHY ARE YOU CHANGING YOUR ANALYSIS?

A. I am doing so to reduce controversy and to recognize the Company's legitimate point that there would be shutdown and restart costs (and ongoing caretaker costs) associated with a shutdown. Based on Company cost data, it appears that there may be some savings available under a temporary shutdown scenario, but since there is insufficient time to

conduct the detailed analysis, I am using the more conservative (and simpler) approach of assuming continued operations with the losses.

As shown on Schedule MIK-1, page 2 of 2 (update), there is an overall stranded cost loss from Cheswick of $36.9 million. Despite this loss, Cheswick should be retained because of the life extension benefits shown in my original study.

Q. WHAT IS YOUR SECOND ADJUSTMENT?

A. My original study included a productivity adjustment of 1.0 percent per year for ten years beginning in 2003 applied to fixed O&M and A&G. The purpose of this adjustment was to recognize that in competitive markets we would expect cost control efforts on an ongoing basis to result in operating costs increasing less rapidly than inflation. Fixed O&M and A&G expenses are a potential area of cost control.

I continue to believe that an adjustment for productivity is appropriate and reasonable. However, for reasons of consistency I have made a revision to that adjustment. Since my analysis finds only three of Duquesne's units to be economically viable (Cheswick, Sammis and Mansfield), I have revised the adjustment so that it applies only to those three plants. As a result of this restriction, the net of tax adjustment declines from $25.2 million to $13.0 million, as shown on Schedule MIK-6, December 1997 update.

I would note that even for these three plants, this is a very modest adjustment amounting to only about 5 percent of projected fixed O&M and A&G costs. Duquesne witness Karl erroneously suggests that I am attempting to impose a 40 percent reduction. I believe he may have misread my testimony in which I cited a U.S. Department of Energy study. That study suggested a 40 percent savings as a high efficiency sensitivity case, but I did not adopt it. Also, it should be noted that my study assumes no cost savings efficiencies for nuclear plants.

1 Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

2 A. Yes, it does.

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

SCHEDULES ACCOMPANYING THE

SURREBUTTAL TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

DECEMBER 1997

EXETER
Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

DUQUESNE LIGHT COMPANY

OCA Overall Stranded Cost Summary
as of 12/31/98
(millions $)

Owned Generation[1]	$1,233.31
Regulatory Assets[2]	408.07
Transition Costs[2]	18.20
Total stand-alone[3]	$1,659.58
Total w/merger[3]	$1,507.30

(1) Source: Schedule MIK-1, page 3 of 3, December 1997 Update. This is stand-alone amount.

(2) Source: Schedule TSC-1. The Beaver Valley 2 lease, which is included on Mr. Catlin's regulatory asset schedule, is removed from the regulatory assets reported above and classified under owned-generation.

(3) 0.1 percent of total should be allocated to FERC jurisdiction.

DUQUESNE LIGHT COMPANY

Owned-Generation Stranded Cost Summary
Before Adjustments
(millions $)

Plant	Net Book Value @ 12/31/98	NPV Net Margins[1]	NPV Decommissioning Cost[3]	Initial Stranded Cost
Perry	$232.34	$0	$18.93	$ 251.27
Beaver Valley 1	212.14	0	17.52	229.66
Beaver Valley 2[4]	545.84	0	8.02	553.86
Elrama	90.39	0	-	90.39
Cheswick	105.46	(36.9)	-	142.36
Mansfield	94.81	129.6	-	(34.79)
Sammis	33.31	3.4	-	29.91
Eastlake	30.97	0	-	30.97
Brunot Island	17.06	0	-	17.06
Owned-Units Subtotal	$1,362.32	$99.4[2]	$44.47	$1,307.39
Working Capital	$61.53	$15.91	-	$ 45.62
Cold Reserve Plants[5]	$64.06	$0.00	-	$ 64.06
Total	**$1,487.91**	**$115.31**	**$44.47**	**$1,417.07**

(1) Excludes fossil decommissioning costs. Negative net margins are treated as zero.

(2) The total has been increased by 3.4 percent (a half-year of discounting) to account for the fact that Duquesne's cash flow model applies a full year discount in the first year.

(3) Source: Schedule TSC-2. Mr. Catlin's annual revenue requirement for 1999-2005 is converted to a NPV amount at 1/1/99 using a 6.88 percent discount rate.

(4) Beaver Valley 2 amount is the sum of reported net book value ($32.48 million) plus the NPV of the lease ($513.36 million). Source: Schedule TSC-1.

(5) This includes $3.48 million of remaining net book value for the Warwick mine at 12/31/98.

DUQUESNE LIGHT COMPANY

Owned-Generation Stranded
Cost Summary with Adjustments
(millions $)

Basic Model Results Before Adjustments:	$1,417.07[1]
Productivity Adjustment:	(13.04)[2]
Life Extension:	(170.72)[3]
Net Merger Savings:	(152.28)[4]
Net Stranded Cost w/o Merger	**$1,233.31**
Net Stranded Cost w/Merger	**$1,081.03**

[1] Source: Schedule MIK-1, page 2 of 3, December 1997 Update.
[2] Source: Schedule MIK-6, page 1 of 1, December 1997 Update.
[3] Source: Schedule MIK-8, page 7 of 7. Based on $300 per kW cost assumption.
[4] Source: Schedule MIK-9, page 1 of 1.

DUQUESNE LIGHT COMPANY

Productivity Enhancement Savings[1]
($ millions)

Year	O&M	A&G	Total	Productivity Adjustment Factor[2]	Savings	Present Value Savings @ 6.88 %
1999	$22.06	$20.24	$42.30	--	--	--
2000	18.07	22.93	41.00	--	--	--
2001	19.91	24.47	44.38	--	--	--
2002	19.89	24.14	44.04	--	--	--
2003	21.20	26.39	47.58	0.0100	$0.48	$0.35
2004	17.18	31.66	48.84	0.0201	0.98	0.68
2005	23.46	27.81	51.27	0.0303	1.55	1.01
2006	20.66	29.94	50.60	0.0406	2.05	1.25
2007	22.87	33.37	56.24	0.0510	2.87	1.63
2008	23.72	33.35	57.06	0.0615	3.51	1.87
2009	24.42	34.88	59.29	0.0721	4.28	2.13
2010	18.29	40.23	58.52	0.0829	4.85	2.26
2011	21.39	30.51	51.90	0.0937	4.86	2.12
2012	20.38	32.43	52.81	0.1046	5.52	2.25
2013	22.33	35.20	57.53	0.1046	6.02	2.29
2014	22.42	35.56	57.97	0.1046	6.07	2.16
2015	6.19	12.60	18.79	0.1046	1.97	0.66
2016	4.98	11.06	16.04	0.1046	1.68	0.52
2017	3.20	8.81	12.01	0.1046	1.26	0.37
2018	3.66	9.81	13.47	0.1046	1.41	0.39
2019	3.77	9.60	13.37	0.1046	1.40	0.36
Totals	$360.06	$534.97	$895.03	--	$50.75	$22.28
Total (net of tax)						**$13.04**

[1]Includes only O&M and A&G for the following plants: Cheswick, Sammis and Mansfield 2 and 3.
[2]Assumes a productivity or cost savings gain of 1.0 percent per year beginning in 2003 for ten years.

DUQUESNE LIGHT COMPANY

Projected Pre-Tax Operating Losses During Transition
(millions $)

Plant	1999	2000	2001	2002	2003	2004	2005	Total
Cheswick	$18.15	$22.12	$17.68	$14.96	$29.02	$69.56	$13.91	$185.21
Sammis	6.18	2.60	11.52	3.56	4.97	0.96	5.40	35.19
Eastlake	5.98	4.61	10.93	11.80	5.97	7.87	10.37	87.53
Elrama	37.92	36.95	30.73	25.88	26.90	21.44	-	179.82
Beaver Valley 2	11.82	2.64	7.19	6.74	0.63	5.45	5.24	39.71
Perry	28.44	17.78	24.50	16.51	22.61	14.56	21.63	146.03
Brunot Island	3.27	1.68	1.70	1.73	1.75	6.57	0.44	17.14
	$111.76	$88.38	$104.25	$81.18	$91.85	$126.41	$56.99	$690.82

Source: Exhibit DJC-20, page 3-16. This schedule excludes the operating losses of Mansfield and Beaver Valley 1 since the Company's analysis indicates that those plants have some positive market value.

OCA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF DUQUESNE LIGHT COMPANY FOR APPROVAL OF RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	:	Docket No. R-00974104

DIRECT TESTIMONY

OF

DOUGLAS C. SMITH

On Behalf of:

OFFICE OF CONSUMER ADVOCATE

NOVEMBER 1997

TESTIMONY OF DOUGLAS C. SMITH

Introduction

Q: PLEASE STATE YOUR NAME, CURRENT OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Douglas C. Smith. I am Technical Director at La Capra Associates, 333 Washington Street, Boston, MA 02108.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I received a Bachelor of Science degree in Mechanical Engineering from Brown University, Providence, Rhode Island, in May, 1986. I joined the Vermont Department of Public Service ("the Department") as Power Cost Analyst in 1986, and was promoted to the position of Electrical Planning Engineer in 1988. My responsibilities at the Department included the examination of electric utility power costs for ratemaking purposes, the analysis of short and long term power purchases, and other electric utility planning analyses.

Since joining La Capra Associates in 1991, I have worked for a range of clients in the energy industry, including regulated utilities, state regulatory agencies, non-utility power producers, and customers. I have performed dispatch simulations of numerous electric utility systems -- including the New England Power Pool, the Puerto Rico Electric Power Authority, the state of Maharashtra (India), and numerous individual U.S. utilities -- to examine the cost and reliability implications of alternative resource choices and planning assumptions. I have conducted solicitations for electric energy and capacity transactions, and have managed the power supply of the Vermont Electric Cooperative, Inc. since 1991. I have provided expert testimony regarding electric utility planning issues, avoided

costs, and power costs in the context of rate cases. A copy of my resume is attached as Exhibit DCS-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present an analysis of Duquesne Light Company's ("Duquesne") future variable generation costs and generation market revenues for use in OCA witness Matthew Kahal's analysis of stranded generation costs. My analysis provides a basis for the Commission to evaluate Duquesne's future generation revenue consistently with that of the other Pennsylvania utilities. I have presented a similar analysis (using the same general methodology and input assumptions) on behalf of the OCA in restructuring dockets involving PECO Energy, Pennsylvania Power and Light, Met-Ed/Penelec, and West Penn Power.

Q. PLEASE SUMMARIZE YOUR ANALYSIS.

A. I have conducted a detailed generation market analysis of the Allegheny Power System and Duquesne Light ("APS/DQL"), similar in structure to market analyses presented by other Pennsylvania electric utilities, based largely on publicly available input data. The analysis reflects what I believe to be reasonable input assumptions regarding the cost of new electric generation options, and the way generators will bid their output in a market environment. The analysis reflects fuel price escalation rates from the Spring 1997 *DRI World Energy Service U.S. Outlook*. Based on the methodology and input assumptions described below, my analysis presents a reasonable estimate of the likely generation market conditions that Duquesne will face, and thus an appropriate basis upon which to estimate Duquesne's stranded generation costs.

Q. WHY DID YOU CONDUCT AN INDEPENDENT GENERATION MARKET ANALYSIS?

A. First and perhaps most important, my analysis provides the Commission with a practical

mechanism to assess the stranded costs and restructuring plans of all Pennsylvania utilities using a common basis of methodology and assumptions.

Moreover, my analysis is intended to assist the Commission by providing a balanced, non-utility perspective on generation market issues. As discussed above, the Commission should be aware that some assumptions supporting the Company's stranded cost analysis appear optimistic, or are not well supported and could turn out significantly differently. My approach in developing assumptions and methods for use in my alternative analysis was not to develop a high bound on market prices and revenues; I have attempted to seek a reasonable expected value outcome on each issue. I believe that I have chosen assumptions that have an equivalent likelihood of being above or below the actual outcome.

Finally, Duquesne has not presented a projection of market price and generation revenue beginning in 1999.

Market Price Methodology

Q. PLEASE SUMMARIZE THE FUTURE GENERATION MARKET IN WHICH DUQUESNE WILL SELL THE OUTPUT OF ITS GENERATING UNITS.

A. My estimate of generation market revenues assumes that there will exist a competitive spot market for wholesale electricity in which bidders (i.e., generators) offer their services at market-based prices of their own choosing. A system operator will select from among the available bids with the goal of minimizing the total system cost. All successful bidders during a given period (e.g., an hour) are assumed to receive the price of the highest successful bidder. Such wholesale electricity markets are being established in several areas of the U.S., including New England, New York, the Pennsylvania-New Jersey-Maryland Interconnection ("PJM"), and California. Such a market has not yet been established in the eastern area of the East Central Area Reliability Coordination

Agreement ("ECAR") where Duquesne's generating sources are located, and the specific transaction rules that may govern the market are not yet known. I believe, however, that my general approach -- to value the output of its generating units' output at the marginal cost of production for the region in which they operate -- is reasonable and consistent with the rules that have been (or are being) established for other major electricity markets. A market participant in the region evaluating a potential wholesale power transaction would likely utilize a similar approach.

The principal buyers of energy and capacity will be load serving entities, which today consist of electric utilities like Duquesne which sell electricity to retail customers. Under retail competition, load serving entities could also include new entrants that seek to sell electricity at retail, and either generate their own power or purchase it from others. Load serving entities will require sufficient electric energy to serve their customers' peak electricity demand, along with a reserve margin of installed generating capacity to call upon in times of high demand and/or outages of major generating units. The electricity market represents an hourly interaction between supply (the various generating units available within the market area, and purchases from outside the area) and demand; I have approximated this interaction using the ENPRO production simulation model, as I will describe below.

I assume that new market entrants (i.e., newly constructed generating units) and existing generating units will enter and leave the market based on market price signals -- i.e., whether their expected energy revenues are sufficient to cover their expected going-forward costs of operation. Depending on the market structure ultimately selected, the products traded would likely include energy and ancillary services (e.g., spinning reserve), and could also include installed capacity (as proposed in NEPOOL and PJM).

Q. PLEASE SUMMARIZE THE METHODOLOGY UPON WHICH YOUR MARKET

PRICE ANALYSIS IS BASED.

A. To simulate the interaction between the supply of and demand for electricity, I conducted a dispatch analysis of the APS/DQL system using the ENPRO dispatch simulation model. ENPRO is a detailed, chronologic model well suited to represent a large electric system. The model is used by utilities and others for a range of operational and planning analyses. ENPRO represents unplanned (or "forced") outages of generating capacity randomly on a daily basis, and planned outages are scheduled to the extent possible during offpeak periods. ENPRO was used to represent the APS/DQL system as a single market area. Imports are represented explicitly as available sources to be dispatched when economic. I have represented the energy market in terms of bids for delivered energy from each generating unit, with each bidder assumed to bid a price sufficient to recover its **average variable cost**, based on the unit's historical as-operated heatrate.

I assume that over time, market prices must be sufficient to support the cost of the new market entrants: newly constructed CT units for peaking duty, and CC units for baseload/intermediate duty.

Q. AT WHAT PRICES DO YOU ASSUME GENERATORS WILL OFFER THEIR OUTPUT TO THE MARKET?

A. In general, offers by owners of generating units will cover each unit's variable cost of operation (fuel and variable O&M costs). An owner offering a unit's output at prices above the variable cost runs the risk that the unit will not be selected to operate during some profitable hours. An owner offering output at prices below the unit's variable cost runs the risk that the unit will be selected to operate at a loss. In order for a generating unit to operate profitably, its energy bid will need to reflect its expected fuel consumption over the expected duty cycle, including startup costs (costs associated with the fuel, labor, and operating procedures to start the unit) and potential operation at relatively inefficient output levels. For the purpose of forecasting wholesale energy market prices, I have

approximated the energy bids of most thermal generating units based on their "as-operated" average heatrates, which reflect the units' efficiency under actual operating conditions.

For units that tend to be operated strictly at full load, the as-operated heatrate will tend to approximate the unit's full load average heatrate.[1] For units that are operated regularly at less efficient partial output levels, the as-operated heatrate can noticeably exceed the full load average heatrate.[2] The as-operated heatrate reflects the realistic efficiencies incurred by thermal generating units during operation (including low load and cycling conditions), and the fuel consumed during startups. The actual fuel consumption during relatively short start/stop cycles, and during cycles in which a unit is operated regularly at part load, can also exceed the annual as-operated heatrate.

Q. WHAT OTHER REVENUES, ASIDE FROM ENERGY, MAY DUQUESNE'S GENERATING UNITS OBTAIN FROM THE GENERATION MARKET?

A. One potential source of additional revenue is ancillary services, such as spinning reserve. In addition to procuring energy to meet hourly loads in ECAR, the system operator will also need at all times to procure adequate spinning reserve to maintain system reliability. The term spinning reserve refers to capacity from a generating unit that is online and operating at less than full output, and capable of increasing its output quickly. To the extent that markets are established for ancillary services, as they have been proposed in

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[1] The heatrate (BTU/kWh) is an expression of a generation unit's thermal efficiency: the amount of fuel heat input (in BTU) required to produce each kWh of net electrical output. A low heatrate therefore represents a relatively efficient generating unit. The full load average heatrate represents a generating unit's efficiency operating at full output for a sustained period.

[2] For example, the average heatrate of Fort Martin Unit 1 at full load is 8,808 BTU/kWh, while its 1996 average as-operated heatrate was 9,692 BTU/kWh. Similarly, Bruce Mansfield Unit 1 features a full load average heatrate of 9,348 BTU/kWh, and an average as-operated heatrate of 10,415 kWh.

NEPOOL and PJM, generating units that are able to operate at part load and change output relatively quickly may obtain revenues from providing spinning reserve. My market revenue analysis does not reflect the impact that some ancillary services will have on energy prices. The magnitude of revenues associated with ancillary services could be significant in absolute dollars, although for most generating units it will probably be relatively small compared to energy revenues.

Depending on the market rules that are established, capacity products (such as the Installed Capacity and Operable Capacity products in NEPOOL) may also be traded. Prices of the product(s) that are traded (from a single product of delivered energy to several products) will vary in response to supply and demand. Market participants' entry and exit decisions will reflect the total revenues that they are able to achieve from the products traded, and long run market prices will be shaped substantially by the costs of actual and potential market entrants.

Fuel Prices

Q. HOW WILL FUEL PRICES AFFECT DUQUESNE'S GENERATION MARKET REVENUES AND STRANDED GENERATION COSTS?

A. Duquesne owns generating units which burn a range of fuels, primarily coal. As a result, the Company's future operating costs will depend strongly on the delivered cost of coal, and to a lesser extent on the cost of other fuels such as natural gas and oil.

The market revenues that Duquesne will receive for the output of its generating units will depend significantly on fuel prices faced by the "marginal" generating units in its market region. The existing supply mix in ECAR is similar to Duquesne's, with coal-fired units defining marginal costs during most hours. During some hours of high demand and/or major generating unit outages, marginal sources for Duquesne and ECAR can be more costly oil-fired units, or purchases from neighboring utilities. This coal-dominated power

supply differs from the PJM electricity market, in which higher-cost steam units burning natural gas and oil are more likely to define market prices, particularly during peak hours.

These relationships indicate that in the immediate term, Duquesne's fuel costs and generation market revenues will be much more strongly affected by the price of coal than the price of other fossil fuels. Over time, gas-fired combined cycle generating units are expected to have an increasing effect on market prices, while Duquesne's fuel costs will still be driven primarily by coal. This means that, in general, higher gas prices in the future would tend to increase market energy prices and revenues received by Duquesne's existing generating units and to lower the stranded generation costs associated with those units.

New Generating Capacity

Q. WHAT NEW GENERATING CAPACITY OPTIONS WILL BE AVAILABLE TO MEET DEMAND GROWTH AND REPLACE EXISTING GENERATING UNITS THAT RETIRE?

A. While a range of electric generation technologies may help meet some portions of future electric demands, I have assumed two primary options for new electric generating capacity. For baseload and cycling duty, I assume that large scale combined cycle combustion turbine ("CC") plants burning natural gas will be available for construction when needed. For peaking duty, large scale simple cycle combustion turbine ("CT") units are assumed to be available. Based on current planning assumptions regarding costs, emissions, and other characteristics, the CC and CT options are appropriate and the most favorable for their respective operating roles.

Q. IN PROJECTING GENERATION MARKET PRICES, WHAT ASSUMPTIONS HAVE YOU MADE REGARDING THE COST AND EFFICIENCY OF NEW GENERATING

CAPACITY?

A. In my market price analysis, I have assumed all-in capital costs of $560/kW ($1997) for the CC option, and $296/kW ($1997) for the CT option.[3] I developed these values based on a review of industry data and estimates provided by other Pennsylvania utilities. Exhibits DCS-2a and DCS-2b illustrate the derivation of the new CC and CT capital costs. I expect that many new units will incur higher capital costs than I have assumed, due to one or more of the following factors:

- Greater interest costs during construction;
- Increase in CC/CT equipment costs from current market conditions, which represent a historical low point;
- Greater land costs (my figures reflect a generic land price from the Electric Power Research Institute's "Technical Assessment Guide");
- Greater project development costs, representing the "soft costs" needed for the legal, financing, and permitting efforts needed to develop a successful project;
- Non-standardized plant features, reflecting tradeoffs between plant design and capital cost. For example, combined cycle units with the most complex and efficient steam cycles will tend to cost more, as will units with reliability features such as a bypass stack or multiple shaft design. The 1996 Gas Turbine World Handbook (which I used as a source for equipment costs) states: "These turnkey plant price levels, as noted, are for 'plain vanilla' plant equipment and services. Extended site work such as cogeneration process steam or utility plant tie-ins are not covered, nor are extensive buildings, nor a large inventory of operational

[3] To the extent possible, capital costs for generating units should be compared on a consistent basis. In addition to direct equipment costs, a power plant developer also incurs significant costs for land, electrical interconnection, gas interconnection (as needed), interest during construction, and development costs such as financing and permitting. In this case, I refer to the "all-in" capital cost needed to deliver a generating facility to commercial operation on a given date, which is intended to include all of the items mentioned above.

spares such as combustor baskets, blades and vanes, etc." I have assumed quite competitive reliability (annual availabilities on the order of 90 percent) and thermal efficiencies (as-operated heatrate of 6,700 BTU/kWh) for new CC units; it is unlikely that these high-performance units will also be the cheapest;

- Selective catalytic reduction ("SCR") equipment for control of NOx emissions on CC units. The turnkey equipment costs underlying my estimate include dry low-NOx burners, but not equipment for catalytic reduction of NOx or CO_2 emissions. To the extent that SCR or other control measures are actually required for some or all of the new CC generating units built in PJM, additional capital and operating costs would be required;
- General plant. My cost estimates treat the CC and CT options as stand-alone facilities, and do not include an allocation of general plant which would presumably be incurred by generating companies in the ECAR market.

Any or all of these factors could increase the cost of new capacity (and therefore market power prices) relative to my analysis. I chose somewhat optimistic capital cost assumptions to reflect the fact that: (1) new units at the most preferable sites (e.g. sites with close proximity to fuel and electrical interconnections) may be able to reduce their infrastructure costs somewhat compared to a "greenfield" site; and (2) there is potential for additional improvement in the CT and CC technologies over the planning horizon.

Q. GIVEN THE CAPITAL COST ASSUMPTIONS DESCRIBED ABOVE, WHAT LEVEL OF MARKET PRICES WILL THE CC AND CT OPTIONS REQUIRE IN ORDER TO BE ECONOMICALLY VIABLE?

A. I have represented the capital-related costs (including return of and on investment, property tax, insurance, and income taxes) associated with new generating units in terms of an annual "fixed charge rate" (or, carrying charge rate) expressed as a percent of the project's initial capital cost.

For the purpose of my analysis, I have assumed a "real-levelized" carrying charge rate of 12.75 percent. This means that for every $100 of capital cost for a new CC or CT plant, the revenue needed to provide recovery of and on the initial investment would be $12.75 in the first year of operation, and in each subsequent year would increase at the rate of general inflation. My experience with actual projects under development indicates that higher market revenues, implying a carrying charge rate several percentage points higher, may be required for a project to be attractive from the perspective of potential equity investors and lenders.

Q. HOW WILL GENERATORS COVER THEIR FIXED COSTS OF OPERATION?

A. My analysis assumes that all generators selling into the spot market at any given time (e.g., hour) will receive the same price for their output, and that the price will reflect the highest bid accepted by the system operator. This means that during the hours when a particular generator is selected to operate, it will receive a price equal or greater than its own bid, resulting in a "contribution" of net revenue to offset the generator's fixed costs of owning and operating its generating source(s). The extent of the contribution that each generator earns will determine the generator's economic competitiveness. In order to be economically viable a generator will, on a sustained basis, need to recover both its variable and fixed costs from the generation market. As discussed above, I assume that each generating unit in the market will bid its hourly output based only on its variable cost. If this is the case, then those generating units with relatively high variable costs that run infrequently would receive little or no contribution toward their fixed costs.

On the one hand, this is an expected and desirable result. Generating units that are relatively costly or inefficient will have difficulty competing in the market. On the other hand, the assumption of bids based strictly on variable costs can conflict with the fact that a reliable electric system will require some amount of "peaking" capacity

designed for occasional use when other generating units experience outages, or during very high demand periods. Without some mechanism for achieving additional revenue during peak periods, such generating units with the highest variable costs would receive little or no energy revenues to offset their fixed costs, and would not be economic to operate on a going-forward basis.

In actual practice, there will likely be several ways for generators in ECAR to be compensated for the "reliability value" of their generating units. First, generating units (i.e. combustion turbines) that are likely to define the market price during peak hours may attempt to bid in excess of their variable costs at times; I have assumed no such bidding in my ENPRO analysis. To the extent that **bids above variable cost** do not exceed the willingness of customers to pay for peak electricity, such bids may be a realistic option.

Second, customers may be willing to reduce their consumption at times, in exchange for **interruptible demand** payments that exceed the variable cost of generating units in the market. In such instances, the market energy price would presumably be defined by the highest price paid to curtail customer load.

The third option is **bilateral transactions**. In order to ensure that they are able to deliver the reliability level(s) that their particular customers require, load serving entities may choose to contract directly with suppliers for the output of specific generating units or system power, rather than relying on the spot market for all of their needs. Similarly, developers of new generating capacity (particularly units intended for peaking duty) will have an incentive to seek a secure market for their output, rather than relying on spot market revenues during volatile peak hour conditions.

Finally, as I noted earlier, some generating units will likely obtain revenues for providing **ancillary services**. While these revenues are difficult to predict, and we have not attempted to quantify them in this analysis, they could provide a source of revenues above the hourly energy market.

Q. DO YOU EXPECT THAT GENERATION MARKET PRICES WILL REFLECT SOLELY THE VARIABLE COST OF THE MOST COSTLY GENERATING UNIT OPERATING IN EACH HOUR?

A. No, I expect that a combination of the mechanisms I described above will yield market prices sufficient to support the level of system reliability that customers desire, or that is established through minimum capacity requirements. Thus, generation market prices will most likely exceed the variable cost of the highest-cost generating unit(s) in the market during some fraction of the year, resulting in what I will call "reliability-related" prices and revenues. The exact form and timing of these reliability-related revenues is uncertain, but it is reasonable to expect that they will be concentrated in relatively few peak hours, or (equivalently) received through fixed payments not tied to actual energy production.

For the purpose of my market price analysis, I assume that generating units will be able to achieve reliability-related revenues which in the long run are capped at the estimated cost of peaking capacity -- that is, the real-levelized carrying cost of a newly constructed combustion turbine. I assumed that these revenues would be concentrated in only the highest-demand hours, so that all generating units would receive the same reliability-related revenues on a per-kW basis. I assumed that sufficient generating capacity will be constructed to maintain an eight percent reserve margin of installed capacity, above the annual peak demand.

Q. COULD ACTUAL MARKET PRICES TURN OUT HIGHER?

A. Yes, for several reasons. First, the neighboring PJM market requires a higher capacity reserve margin than Duquesne or ECAR, and is expected to need additional generating capacity earlier. To the extent that some generating capacity in ECAR is sold to PJM, upward pressure would be exerted on ECAR market prices sooner than I have assumed. Similarly, NEPOOL will have a need for significant additional capacity in the next several years, due primarily to the retirement of the Connecticut Yankee (560 MW) and Maine Yankee (880 MW) units, and to the continued unavailability of three units on the Nuclear Regulatory Commission's Watch List: Millstone Units 1, 2 and 3, with a total capacity of over 2,600 MW. I also understand that during 1997 Ontario Hydro has shut down several thousand MW of nuclear generating capacity. To the extent that these or other major generating units in the Northeast and Mid-Atlantic remain unavailable, upward pressure will be exerted on energy and capacity prices.

Second, the generation market will be affected not only by the amount of installed capacity, but also by the economic competitiveness of that capacity. Because revenues will not be guaranteed in a competitive generation market, the owner of a generating unit with relatively high going-forward costs may choose to close the unit for economic reasons, even if the unit is still physically operable. I did not test the economic viability of the existing generating units in ECAR, and assumed that the existing units would continue to operate. To the extent that any "economic retirements" occur, actual market electricity prices will exceed those projected in my analysis.

Q. PLEASE SUMMARIZE THE PRIMARY INPUT ASSUMPTIONS UTILIZED IN YOUR PJM MARKET ANALYSIS.

A. The fundamental input assumptions (or groups of assumptions) in my analysis are generally based on publicly available data. The primary assumptions are as follows:

- **Generating units** and their seasonal maximum **capacities** were identified from the 1996 NERC Electricity Supply and Demand database, and the FERC Form 1.

The APS/DQL control area was defined to include generating capacity owned by affiliates of APS (West Penn, Monongahela Power, and Potomac Edison), and Duquesne.

- Actual annual **fuel prices** for existing generating units were obtained on a station basis for calendar year 1996, from FERC Form 423. From 1997 forward, fuel prices for most units were escalated according to major fuel type (e.g., coal, residual oil, distillate oil, natural gas), based on escalation rates from DRI's Spring 1997 price forecast; these annual escalation values are presented in Exhibit DCS-3;
- The base **fuel prices** at Hatfield Ferry, Bruce Mansfield, Elrama, and Mitchell stations were adjusted downward from historical values to reflect the anticipated expiration of above-market coal supply contracts. The base prices assumed for Hatfield Ferry and Mitchell are those assumed by West Penn in Docket R-00973981; the base prices assumed for Bruce Mansfield and Elrama are those assumed by Duquesne witness Mark Karl.
- **Fuel prices** at Hatfield Ferry, Harrison, and Pleasants were adjusted from the year 2003 forward to reflect the planned utilization of gas reburn to control NO_x emissions.
- **Variable O&M costs** of existing generating units were based on assumptions presented by PECO in Docket R-00973877. These values, which include only direct O&M costs and not emission adders, are the same as those assumed by West Penn in Docket R-00973981.
- **Emission adders** for SO_2 and NO_x were added to the dispatch price of thermal units, using the real ($1997) values estimated by West Penn in Docket R-00973981. I did not assume any additional costs or adders associated with the control of CO_2 or particulates.
- **Heatrates**: the energy bid of each thermal generating unit is represented based on its average as-operated heatrate for 1996, as obtained from the FERC Form 1.

This is the bid which will, over a generating unit's dispatch cycle, approximate the unit's total actual variable costs;

- Generating unit **availabilities** were developed for major classes of generating units, based on NERC records of 1990-1994 actual generating unit availabilities, with the following exceptions: (1) Output of the Lake Lynn hydro station was based on the annual output of 197.8 Gwh assumed by WPP in Docket R-00973981; (2) The Perry and Beaver Valley nuclear generating stations were assumed to produce at a 75 percent annual capacity factor.
- **Non-utility generating capacity** was projected in accordance with the NERC 1996 Electric Supply and Demand Database. Unit cost and energy production assumptions were developed from the FERC Form 1.
- Projected **peak load and energy** requirement growth rates were based on the 1996 NERC Electricity Supply and Demand database; the hourly load shape was based on an average of the 1995 and 1996 actual hourly shapes.

Q. WHY HAVE YOU UTILIZED THE DRI FORECAST AS THE BASIS FOR PROJECTING FOSSIL FUEL PRICES IN YOUR ANALYSIS?

A. In Docket R-00973953, the OCA reviewed projections of market price and stranded costs presented by PECO Energy; two of PECO's three projections in that case were developed using the DRI Spring, 1997 fuel price forecast. The OCA chose to evaluate PECO's stranded costs using the same fuel price and inflation outlook because the values in the DRI forecast appear reasonable for planning purposes. DRI is a well-known forecasting firm that has been used in numerous electric industry analyses, and the use of common planning assumptions would focus the discussion on differences in methodology and other input assumptions. Those reasons remain valid today. Because one of the OCA's goals is to facilitate an evaluation of stranded costs for all Pennsylvania utilities on a common basis, I have estimated generation market revenues for PECO, Pennsylvania Power and Light, Penelec, Met-Ed, and now Duquesne and West Penn using the same

input assumptions and methodology.

Market Price Results

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR MARKET PRICE ANALYSIS.

A. Exhibit DCS-4 and DCS-5 summarize the results. Exhibit DCS-4 presents the projected annual average market energy price, annual market capacity price, and total market price (including energy and capacity) from 1999 to 2015. These values represent the unweighted average of market prices for all hours of the year, and would represent the realized wholesale market revenue of a generating source producing at maximum capacity during all hours of the year.

Exhibit DCS-5 presents the average annual energy and capacity revenues projected to be achieved by Duquesne's generating units in each year of the analysis. Because some of the Duquesne generating units are load-following, and tend to produce during the higher-cost peak hours, the achieved market prices in Exhibit DCS-5 are somewhat higher than the unweighted averages in Exhibit DCS-4.

Q. PLEASE DESCRIBE THE CONSTRAINTS ON YOUR MARKET ANALYSIS.

A. My energy market analysis is conservative (i.e. tends to understate market prices) in at least three ways. Most important, my analysis assumes that (with the exception of specific retirements outlined above), the existing stock of generating units in APS/DQL and the rest of ECAR will continue to operate through the planning horizon. West Penn's analysis in Docket R-00973981 indicates that this assumption may be optimistic, and that a significant amount of existing coal-fired capacity may not be economically viable in a competitive market based on going-forward costs. To the extent that any existing capacity is retired, higher-cost generating units will be called upon to operate more frequently and actual market prices will exceed those projected in my analysis.

Second, my analysis reflects generation and costs to serve only load in the APS/DQL area, and does not reflect any future sales for resale. In the past Duquesne has made significant sales for resale, largely to PJM utilities. While such resales cannot be predicted with certainty, it appears that typical market prices in PJM will remain higher than in ECAR for some time, and that Duquesne will therefore be able to make profitable sales for resale. To the extent that resales occur, they will increase generation from the Company's marginal generating units, increase the net margins of those units, and potentially raise the clearing price received by all Duquesne units.

Finally, the commitment and dispatch of generating units in my analysis does not reflect spinning reserve requirements, which will tend to require commitment of additional, more costly thermal generating units.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My analysis of market prices and generation market revenues provides a practical way for the Commission to implement consistent market price assumptions in its determination of stranded generation costs for Pennsylvania utilities. It is important to note that my analysis was not developed to represent a high bound on market prices and revenues. A host of factors -- including environmental compliance costs, higher fossil fuel costs, poor performance of existing generating units, higher costs or carrying charge rates for new generation, and profitable sales for resale -- could significantly increase Duquesne's net generation revenue relative to my analysis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

44568

DOUGLAS C. SMITH

Mr. Smith is Technical Director at La Capra Associates with over ten (10) years of experience in utility economics and planning. In four years as Electrical Planning Engineer and Power Cost Analyst for the Vermont Department of Public Service, Mr. Smith specialized in electric utility power costs, resource planning, and modeling issues. Since joining La Capra Associates in 1991, Mr. Smith has assisted a range of utility and non-utility clients in the areas of resource planning, operational issues, and market transactions.

Mr. Smith's professional accomplishments include:

- Manages and conducts all power transactions of the Vermont Electric Cooperative, Inc., a New England Power Pool member. Responsibilities include initial evaluations of capacity and energy need, system simulations, negotiation with potential trading partners, and development of contract terms.

- On behalf of several electric utility clients, evaluated and ranked numerous multi-year power supply proposals, based on analysis of the proposals' performance (individually and in combination) in the purchasers' power supply portfolios.

- Presented expert testimony before state regulatory commissions in dockets relating to electric utility planning, rate cases, and future market prices in a competitive generation market.

- Participated in La Capra Associates' 1997 analysis of future wholesale electricity prices in a deregulated generation market, on behalf of the New Hampshire Public Utilities Commission.

- Performed detailed, probabilistic dispatch simulations of electric utility systems -- including the New England Power Pool, the state of Maharashtra (India), and numerous individual U.S. utilities -- to identify the production cost implications of alternative resource choices and planning assumptions.

- Examined in detail the technical and economic feasibility of self-generating steam and chilled water to serve the medical campus of Boston City Hospital and Boston University.

- Determined the amount of additional generating capacity required by the Puerto Rico Electric Power Authority to maintain its reliability objectives, and identified how those needs would vary under alternative planning assumptions. Supported the results in oral testimony before the Planning Board of Puerto Rico.

- On behalf of the World Bank, assisted in the firm's review of technical and policy issues related to the acquisition of non-utility power in India.

- On behalf of state regulatory agencies, performed comprehensive analyses of numerous wholesale electric power transactions, including domestic and international transactions of up to 20 years in duration.

- Played a lead role in the solicitation, evaluation, and negotiation of long term power supply agreements for the Nantucket Electric Company and the Vermont Electric Generation &Transmission Cooperative, Inc.

- Critically evaluated a long term transmission contract between two New England electric utilities. Identified inappropriate assignment of costs to transmission customers, and an overstatement of electrical losses associated with deliveries to the customers. Developed written testimony for submission to the Federal Energy Regulatory Commission. Participated in the negotiation of a successful settlement, which will provide the customer with a substantial refund of back charges and a significant reduction in future charges.

- Developed a generating unit dispatch plan to minimize fuel and operating costs for the Nantucket Electric Company, taking into account factors such as part load thermal efficiencies and system operating reserve.

- Managed the development of Integrated Resource Plans for several electric utilities.

- Developed "avoided cost" rates to represent the value of electric power from Qualifying Facilities, and from demand modifications associated with utility Demand-Side Management ("DSM") programs.

Mr. Smith has previously served in the following professional capacities:

- Electrical Planning Engineer, VERMONT DEPARTMENT OF PUBLIC SERVICE. October, 1988 to December, 1990.
- Power Cost Analyst, VERMONT DEPARTMENT OF PUBLIC SERVICE. June, 1986 to October, 1988.

EDUCATIONAL BACKGROUND:

- Sc.B. in Mechanical Engineering with Energy Conversion emphasis, **BROWN UNIVERSITY**, Providence, Rhode Island.
- EPRI Seminars on Utility Planning and Production Costing Techniques.
- Users' group and other training seminars associated with the UPLAN and ENPRO production costing models.

New Combined Cycle Non-Fuel Cost Assumptions

Unit Characteristics		Source
Nominal Size (MW)	500 MW	Based on data from Gas Turbine World 1996 Handbook
Summer MW (90 degrees F)	450 MW	1993 EPRI TAG
Primary Fuel	Natural Gas	
HHV Heat Rate at ISO	6,700 Btu/kWh	Based on data from GTW 1996 Handbook

Components of Capital Cost		Source
Turnkey Capital Costs at ISO (1996$/kW)	425 $/kW	Low end based on data from GTW 1996 Handbook
Switchgear Cost	25 $/kW	Obtained from GE by PHB; PECO mkt. price testimony
Gas Pipeline Cost (5 miles)	4 $/kW	Oil and Gas Journal, 25 Nov. 1996 *
Electrical Transmission (10 miles)	4 $/kW	Obtained from GE by PHB; PECO mkt. price testimony *
Land Cost (100 acres)	0.1 $/kW	1993 EPRI TAG *
Infrastructure	9 $/kW	PHB estimate; PECO mkt. price testimony *
More Complex CC Design	0 $/kW	
SCR for NOx Control	0 $/kW	
Decommissioning	0 $/kW	
Plant Development / Siting	10 $/kW	LCA estimate
Interest During Construction (5%)	19 $/kW	LCA estimate
All-in Costs (1996$/kW)	**496 $/kW**	
All-in Costs @ Summer Rating (1996$/kW)	**550 $/kW**	

* Note that these per kW costs are based on installation at a 1125 MW station.

New Combustion Turbine Non-Fuel Cost Assumptions

Plant Characteristics		Source
Nominal Size (MW)	250 MW	Based on data from Gas Turbine World 1996 Handbook
Summer MW (90 degrees F)	220 MW	1993 EPRI TAG
Primary Fuel	Natural Gas	
Secondary Fuel	FO2	
HHV Heat Rate at ISO	11,000 Btu/kWh	Based on data from GTW 1996 Handbook

Components of Capital Cost		Source
Turnkey Capital Costs at ISO (1996$/kW)	185 $/kW	Low end based on data from GTW 1996 Handbook
Delivery Charges (3%)	6 $/kW	
Step-up Transformer & Switchgear Cost	40 $/kW	Obtained from GE by PHB; PECO mkt. price testimony
Gas Pipeline Costs	0 $/kW	
Distillate Tank	2 $/kW	1995 Means Site Work and Landscape Cost data *
Electrical Transmission (10 miles)	5 $/kW	Obtained from GE by PHB; PECO mkt. price testimony *
Land Cost (100 acres)	0.1 $/kW	1993 EPRI TAG *
Infrastructure	5 $/kW	PHB estimate; PECO mkt. price testimony *
Plant Development / Siting	8 $/kW	LCA estimate
Interest During Construction (2.5%)	4 $/kW	LCA estimate
All-in Costs (1996$/kW)	**255 $/kW**	
All-in Costs @ Summer Rating (1996$/kW)	**290 $/kW**	

* Note that these per kW costs are based on installation at a 1000 MW station.

SPRING 1997 DRI FUEL PRICE ESCALATION RATES *

YEAR	GAS	COAL 1	COAL 2	F02	FO6
1997	-10.5%	-0.8%	1.9%	-7.2%	-4.9%
1998	-10.6%	-0.8%	1.6%	-0.8%	-2.5%
1999	-1.1%	0.8%	3.2%	-0.6%	-1.9%
2000	1.7%	1.5%	3.3%	2.9%	2.6%
2001	6.2%	1.5%	2.2%	5.4%	5.6%
2002	5.1%	1.5%	2.1%	4.7%	4.7%
2003	3.9%	1.5%	1.5%	4.9%	4.8%
2004	3.7%	2.2%	2.5%	4.6%	4.7%
2005	3.8%	1.4%	1.1%	5.8%	6.2%
2006	4.0%	2.1%	2.0%	5.3%	5.3%
2007	4.8%	2.0%	1.9%	5.2%	5.2%
2008	4.9%	2.7%	2.0%	5.3%	5.3%
2009	4.9%	1.9%	2.0%	5.3%	5.6%
2010	5.2%	2.5%	2.7%	5.2%	5.2%
2011	4.8%	2.5%	0.2%	5.6%	5.8%
2012	4.4%	2.4%	2.7%	5.4%	5.4%
2013	5.6%	3.0%	2.7%	5.5%	5.7%
2014	5.2%	2.3%	2.7%	5.5%	5.7%
2015	5.6%	2.8%	2.7%	5.7%	5.7%

* Nominal escalation rates assuming a 1996 base year.
Escalation rates for Gas, FO2, FO6, and Coal 2 are for fuel delivered to the Mid-Atlantic region. The escalataion rate for Coal 1 is for fuel delivered to the East North Central region.

EXHIBIT DCS-4

APS-DQL MARKET PRICE ESTIMATE

YEAR		DELIVERED ENERGY $/MWh
		ALL-HOURS
1999		18.83
2000		19.36
2001		19.51
2002		21.60
2003		26.36
2004		27.33
2005		29.15
2006		30.51
2007		32.75
2008		34.90
2009		36.84
2010		38.68
2011		41.70
2012		45.11
2013		47.96
2014		51.27
2015		53.70

DQL WEIGHTED
GENERATION PRICE

YEAR	$/MWH
1999	19.42
2000	19.91
2001	19.96
2002	22.54
2003	29.28
2004	30.25
2005	31.45
2006	32.70
2007	35.08
2008	37.31
2009	39.18
2010	41.00
2011	44.13
2012	47.64
2013	50.47
2014	53.67
2015	56.25

* Delivered Energy

25

OCA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF DUQUESNE LIGHT COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	:	Docket No. R-00974104

SURREBUTTAL TESTIMONY

OF

DOUGLAS C. SMITH

On Behalf of:

OFFICE OF CONSUMER ADVOCATE

DECEMBER 1997

Introduction

Q: PLEASE STATE YOUR NAME, CURRENT OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Douglas C. Smith. I am Technical Director at La Capra Associates, 333 Washington Street, Boston, MA 02108.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted OCA Statement No. 2 and accompanying Exhibits DCS-1 to DCS-5.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I will respond to several issues raised by Duquesne in the rebuttal testimony of Mr. Mark Karl. In particular, I will address Mr. Karl's comments with respect to installed capacity reserve margins and requirements, and with respect to various planning assumptions that include generating unit availability; system load shapes; generating unit heatrates; and fossil fuel prices.

Mr. Karl's observations relating to my testimony focus primarily on generic limitations of input assumptions used in market price forecasts. None of his observations refute the reasonableness of the input assumptions or methodology used in my analysis; in fact, Mr. Karl confirms the reasonableness of some assumptions. Potential variations in the assumptions which Mr. Karl does question would not likely alter the results of my generation market analysis in a substantial way. My analysis remains an appropriate basis upon which to evaluate the future market revenues of the Company's generating sources, and provides the Commission with a basis for evaluating the generation market revenues of all Pennsylvania utilities using a consistent set of planning assumptions.

Capacity Reserves/Market Structure

Q. PLEASE ADDRESS MR. KARL'S COMMENTS WITH RESPECT TO THE USE OF CAPACITY RESERVE TARGETS IN YOUR MARKET ANALYSIS.

A. Mr. Karl correctly states that I have used an 8 percent capacity reserve margin in my generation market analysis; he implies (page 2) that I have assumed this value to represent an administratively determined installed capacity requirement for ECAR. Mr. Karl goes on to state that "It is inappropriate for these witnesses to assume that any particular level of reserves will be required by ECAR in the future; it may be that ECAR permits the market to determine the level of reserves that it is willing to pay for (with the exception, as indicated, of the 6% daily operating reserves.)" (Karl rebuttal, page 3).

First, as a matter of clarification, my analysis is not based on the assumption that the wholesale power market in ECAR will feature an administratively determined capacity payment. Capacity requirements (i.e., the installed capacity reserve margin) are determined by reliability concerns. This reserve margin could be arrived at through an energy-only wholesale market (as the result of interactions between customers and load serving entities), or through the rules (with or without a specific installed capacity requirement) established for particular markets and control areas. However, the magnitude of reliability-related revenues will depend primarily upon the cost of market participants, not the particular market rules. My initial testimony discussed several sources of reliability-related revenue. I did not list an administratively determined capacity payment, although that is one possible market structure.

My analysis does reflect the premise that market entrants will tend to build new generating capacity when expected market prices will support the all-in cost of that capacity. A reliable electric system will include some margin of installed capacity above the peak demand. In an energy-only market, these units will be able to cover their costs in the spot market by receiving energy bids above variable cost, or through bilateral contracts outside the spot market. In a market that includes an installed capacity requirement, the revenue options would also include payments for the product of installed capacity.

Regardless of the market structure, it is not possible to know with precision the level of

reliability, and therefore capacity reserve margins, that customers will prefer in the future. I have assumed that customers will seek a level of system reliability comparable to historical minimum targets, which have been estimated to require approximately an eight percent regional installed capacity reserve margin. It is reasonable to use this approach in the context of forecasting generation market prices.

Generator Availability Assumptions

Q. PLEASE EXPLAIN THE ROLE OF GENERATING UNIT AVAILABILITY ASSUMPTIONS IN YOUR ANALYSIS, AND RESPOND TO MR. KARL'S CONCERNS REGARDING THE SOURCE OF YOUR ASSUMPTIONS.

A. By "availability" we mean the fraction of time during which a generating unit is available to produce electrical output. Units are sometimes unavailable due to planned maintenance projects that are scheduled in advance, and sometimes due to "forced" outages which are unplanned and cannot be deferred. Generating unit availability assumptions can have an effect on forecasted market prices, since outages of baseload units with low variable costs tend to cause the operation of more expensive replacement units. I based the assumed availability of existing generating units on historical availability records for major classes of generating units, as assembled by the North American Electric Reliability Council ("NERC").

Mr. Karl observes (page 4) that the NERC availability data is only available for groupings of plants, and suggests that it is problematic to represent unique units/plants such as Elrama using grouped availability data. While Mr. Karl is correct that the NERC data is published only for groups of units, this is not a fundamental flaw. The future availability of generating units is, of course, uncertain, and even unit-specific availability records provide no guarantee of future performance. In addition, small variations in availability for particular generating units would have only a limited effect on the market prices in an electric system of significant size like the APS/DQL area included in my analysis. For the purpose of forecasting generation market prices and operation across a significant market,

the grouping of availability assumptions is not an important limitation.

System Load Shape

Q. PLEASE ADDRESS THE COMPANY'S COMMENTS REGARDING SYSTEM LOAD SHAPES.

A. The system load shape is one of numerous input assumptions to a market price analysis. In the ENPRO dispatch simulation model, the available generating units and purchases are dispatched to meet the projected system load on an hourly basis. My analysis of the APS/DQL area assumes that annual peak demands and energy requirements will increase as projected for ECAR in the 1996 NERC Electricity Supply and Demand database; the hourly load shape was based on an average of the 1995 and 1996 actual hourly shapes.

Mr. Karl states (page 7) that "Development of a combined load shape [incorporating Allegheny and Duquesne loads] requires an assessment of the individual customer classes of each company." With respect to the base year, this is not the case. The combined load for the two systems in each hour is simply the sum of the hourly loads for the two systems. It appears that Mr. Karl's comments may be directed toward forecasting trends in load shape over time. The hourly load shape in future years is, of course, uncertain, but the relatively stable nature of installed loads and usage patterns make the historical curve the best basis from which to forecast. In addition, short term trends in load shape will likely have only a secondary effect on market prices. Other factors, such as the overall magnitude of electricity demand growth, fossil fuel prices, and the cost of new market entrants, will likely be more important. In the long term, it is reasonable to expect that changes in the system load shape will be partially or entirely offset by changes in the generation mix, with the amounts and type of new market entrants developed to "fit" the actual load shape and market price signals.

Generating Unit Heatrates

Q. PLEASE ADDRESS MR. KARL'S COMMENTS WITH RESPECT TO YOUR REPRESENTATION OF GENERATING UNITS BASED ON THEIR "AS-OPERATED" HEATRATES FROM FERC FORM 1.

A. Mr. Karl does not raise a fundamental disagreement with my use of the as-operated heatrates. My use of historical heatrates, that is, using generating units' recent historical operating roles as a proxy for their future operating roles, is a reasonable approach. Mr. Karl correctly points out that changes in a generating unit's operating role over time could alter the unit's as-operated efficiency and heatrate. A change in a unit's projected capacity factor does not, however, necessarily produce a change in the unit's thermal efficiency. Generating units that are called upon to operate in the same manner (for example, a typical operating cycle of 16 hours, with a typical pattern of startup, ramping to full load, and ramping down) as they were in the past, but are simply called upon to do so more often, are unlikely to experience material changes in their as-operated heatrates.

Fuel Price Assumptions

Q. PLEASE ADDRESS MR. KARL'S TESTIMONY WITH RESPECT TO FUTURE NATURAL GAS PRICES.

A. Mr. Karl states (page 11) that the DRI forecast used in my analysis is a reasonable source of escalation data for coal or nuclear fuel. Mr. Karl raises a general concern with respect to natural gas price forecasts, based largely on Duquesne's finding that past gas price forecasts have overstated actual market prices.

My analysis of generation market prices is intended to reflect the outlook for fuel prices presented in the Spring 1997 *DRI World Energy Service U.S. Outlook*. DRI is a well-known forecasting firm that has been used in numerous electric industry analyses, including some analyses presented by Pennsylvania utilities in their restructuring proceedings. Mr. Karl has not demonstrated that the DRI forecast is flawed in any way. With respect to natural gas prices, it is important to recognize that DRI assumes

substantial decreases in delivered gas prices relative to recent history. For example, in 1996 the actual price of natural gas delivered to electric generators in the Mid-Atlantic and East North Central regions averaged about $2.90/MBTU. For context, DRI projects a delivered natural gas price of $2.34/MBTU for the Mid-Atlantic region in 1999 (the first year of my analysis), and average gas price escalation of about 1 percent per year in real terms over the following decade.

Mr. Karl is, of course, correct that future fossil fuel prices are uncertain and that regardless of the details of current price forecasts, actual prices in the future are likely to be different. This does not mean that fuel price forecasts should not be used to estimate the Company's generation revenues, or that the Company's proposal to value its generating assets at a future date would avoid the uncertainty of fossil fuel prices. In order to value the Company's generating assets--whether through an administrative proceeding, an actual sale of the assets, or an alternative method such as that proposed by Mr. Schnitzer--the process will explicitly or implicitly reflect a best estimate of future generation and market prices based on the information (including forecasted fossil fuel prices) available at a particular point in time. The actual value of output from the Company's generating units ten years hence will depend in part on how actual conditions (including fossil fuel prices and many other factors) turn out, relative to these best estimates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

44985

OCA Statement No. 3

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

DIRECT TESTIMONY OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

NOVEMBER 1997

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

TABLE OF CONTENTS

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

Direct Testimony of Thomas S. Catlin

Introduction

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland 20904. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Master of Science Degree in Water Resources Engineering and Management from Arizona State University (1976). Major areas of study for this degree included pricing policy, economics, and management. I received my Bachelor of Science Degree in Physics and Math from the State University of New York at Stony Brook in 1974. I have also completed graduate courses in financial and management accounting.

Q. WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. From August 1976 until June 1977, I was employed by Arthur Beard Engineers in Phoenix, Arizona, where, among other responsibilities, I conducted economic feasibility, financial and implementation analyses in conjunction with utility construction projects. I also served as project engineer for two utility valuation studies.

From June 1977 until September 1981, I was employed by Camp Dresser & McKee, Inc. Prior to transferring to the Management Consulting Division of CDM in April 1978, I was involved in both project administration and design. My project administration responsibilities included budget preparation and labor and cost monitoring and forecasting. As a member of CDM's Management Consulting Division, I performed cost of service, rate, and financial studies on approximately 15 municipal and private water, wastewater and storm drainage utilities. These projects included: determining total costs of service; developing capital asset and depreciation bases; preparing cost allocation studies; evaluating alternative rate structures and designing rates; preparing bill analyses; developing cost and revenue projections; and preparing rate filings and expert testimony.

In September 1981, I accepted a position as a utility rates analyst with Exeter Associates, Inc. I became a principal and vice-president of the firm in 1984. Since joining Exeter, I have continued to be involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I have been extensively involved in the review and analysis of utility rate filings, as well as other types of proceedings before state and federal regulatory authorities. My work in utility rate filings has focused on revenue requirements issues, but has also addressed service cost and rate design matters. I have also been involved in analyzing affiliate relations, alternative regulatory mechanisms, and regulatory restructuring issues. This experience has involved telephone, natural gas transmission and distribution and water utilities, as well as electric companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS ON UTILITY RATES?

A. Yes. I have previously presented testimony on more than 140 occasions before the Federal Energy Regulatory Commission and the public utility commissions of Arizona,

California, Colorado, Delaware, the District of Columbia, Florida, Idaho, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Ohio, Oklahoma, Rhode Island, Utah, Virginia and West Virginia, as well as before this Commission. I have also filed rate case evidence by affidavit with the Connecticut Department of Public Utility Control. A copy of my resume with a complete listing of my prior testimony is included as Attachment A to my testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am appearing on behalf of the Pennsylvania Office of Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the OCA to assist in the review and evaluation of Duquesne Light Company's (Duquesne's or the Company's) proposed restructuring plan. In particular, I have been asked to address certain components of Duquesne's stranded cost claims including nuclear and fossil decommissioning costs, regulatory assets and liabilities including income taxes, and other transition costs. The purpose of my testimony is to present my findings and discuss the adjustments which I have determined should be made to the Company's claims.

Q. HAVE YOU PARTICIPATED IN THE RESTRUCTURING PROCEEDINGS OF OTHER PENNSYLVANIA UTILITIES?

A. Yes. I have previously submitted testimony on behalf of the OCA in PECO Energy Company's, Pennsylvania Power and Light Company's, Metropolitan Edison Company's and Pennsylvania Electric Company's restructuring filings. I am also currently involved in the restructuring proceedings of West Penn Power Company, UGI Utilities and Pennsylvania Power Company.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Schedules TSC-1 and TSC-2 are attached to my testimony. These schedules present my proposed adjustments to Duquesne's stranded cost claims.

Q. PLEASE SUMMARIZE YOUR FINDINGS WITH REGARD TO REGULATORY ASSETS.

A. In its revised filing, Duquesne has claimed a nominal balance of regulatory assets of $762.19 million as of December 31, 1998. In comparison, I have identified regulatory assets with a nominal balance totaling $936.94 million as of December 31, 1998. The present value of the regulatory assets which I have identified is $882.29 million at Duquesne's net of tax discount rate of 7.83 percent and $921.43 million at the 6.88 percent net of tax discount rate identified by my associate, Mr. Matthew I. Kahal. A breakdown of the individual components of Duquesne's claims and my recommendations regarding regulatory assets is shown on Schedule TSC-1.

In addition to existing regulatory assets, Duquesne also added $18.2 million of transition costs to its regulatory asset claim.[1] At the time of preparation of this testimony, I was still awaiting discovery responses pertaining to these transition costs. Pending receipt of additional cost detail, I have recognized the Company's claimed transition costs as an additional regulatory asset. However, I may revise my recommendation at the time of my surrebuttal testimony.

Q. WHY IS THE LEVEL OF REGULATORY ASSETS WHICH YOU HAVE IDENTIFIED GREATER THAN DUQUESNE'S CLAIM?

A. In its filing, Duquesne has not made a determination of stranded costs as of December 31, 1998. Instead, the Company has compared projected revenues to projected revenue requirements for the years 1999-2005 and used any excess revenues to fund the

[1]Page 2 of Mr. Clayton's revised Exhibit DJC-4, which summarizes Duquesne's regulatory asset claims, includes transition expenses of $18.10 million. However, the breakdown of transition expenses shown on Exhibit DJC-5 shows total costs of $18.2 million.

accelerated amortization of its generation investment. As part of this approach, the Company amortized its regulatory assets as of December 31, 1998 over seven years and included that amortization as part of its revenue requirements. However, in determining the balance of regulatory assets as of December 31, 1998, the Company did not include costs which would already be recovered in rates over the period 1999-2005. Hence, Duquesne's balance of regulatory assets as of December 31, 1998 does not include any amounts related to unamortized debt costs or the Beaver Valley 2 lease payments for the years 1999-2005 because those costs were separately included in revenue requirements.

Under the OCA's approach, a determination of stranded costs as of December 31, 1998 is being made. Therefore, it was necessary for me to calculate the balance of regulatory assets based on the total balance of costs recoverable under traditional regulation as of that date. Accordingly, the balance of regulatory assets which I have identified includes unamortized debt costs and Beaver Valley 2 lease related costs for the years 1999-2005 which were not included as regulatory assets by Duquesne.[2]

Q. WHY HAVE YOU NOT PROVIDED A COMPARISON OF THE NET PRESENT VALUE CLAIMED BY DUQUESNE FOR ITS REGULATORY ASSETS WITH YOUR RECOMMENDATIONS?

A. Consistent with its approach of not making a determination of stranded costs as of December 31, 1998, Duquesne did not calculate the net present value of its claimed regulatory assets. Instead, the Company either included in or excluded from rate base each of its regulatory assets over the proposed seven-year recovery period. For those regulatory assets that were included in rate base, the net present value claimed by

[2]It should be noted that while I have included the present value of the Beaver Valley 2 lease payments as a regulatory asset consistent with Duquesne's presentation, Mr. Kahal has transferred the lease obligation from regulatory assets to owned-generation for purposes of his analysis.

Duquesne is effectively the same as the nominal balance. For those regulatory assets excluded from rate base, Duquesne has effectively claimed a net present value which is less than the nominal balance. In the discussion of my adjustments to regulatory assets, I have noted whether or not Duquesne included the unamortized balance in rate base.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH REGARD TO DECOMMISSIONING COSTS.

A. As explained in more detail in my subsequent testimony, Duquesne has treated the existing nuclear decommissioning trust fund contributions for Beaver Valley 1, Beaver Valley 2 and Perry as a revenue requirement for the years 1999-2005. The Company then has calculated the additional funding which would be required after 2005 to fully fund nuclear decommissioning costs and treated that additional amount as a stranded cost as of that date. Consistent with the OCA's overall approach, I have calculated the annual funding contributions which are necessary to fully fund future decommissioning costs over the 1999-2005 transition period. These fund contributions are developed and summarized on Schedule TSC-2. As indicated there, the total required contributions to fully fund decommissioning costs by 2005 are $7,949,000 per year over the period 1999-2005. In developing this contribution requirement, I have utilized Duquesne's projections of cost escalation rates, fund earnings rates, and expenditure timing. The one change which I made to the Company's cost estimates was to reduce the contingency allowance built into the costs from an average of approximately 20 percent to 10 percent.

I have also adjusted Duquesne's claims for stranded fossil decommissioning costs. In particular, as discussed later in my testimony, it is my recommendation that fossil decommissioning costs should not be considered as an element of stranded costs at all. However, if the costs are to be recognized, the contingencies incorporated in the Company's projected costs should be adjusted downward to a level of no more than ten

percent. In addition, if these costs are to be considered, the determination of the net present value of fossil decommissioning costs should recognize any life extensions for Duquesne's generating units. Finally, the cost escalation rates used to estimate future cost levels and the discount rates used to calculate the net present value of those future expenditures should be consistent with the overall assumptions adopted by the Commission for the determination of stranded costs.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into sections corresponding to the issues which I will address. These topics are summarized in the table of contents for my testimony.

Unamortized Debt Costs

Q. PLEASE EXPLAIN HOW DUQUESNE TREATED UNAMORTIZED DEBT COSTS IN ITS ANALYSIS.

A. Consistent with the overall approach which it took to determining stranded costs, Duquesne divided unamortized debt costs into two components. The first component is the portion of those costs which will be recovered through interest expense in the years 1999 through 2005 as part of the Company's revenue-requirements. The second component is the portion of the unamortized debt costs which would otherwise be recovered as interest expense subsequent to 2005. This second component was treated as a generation-related regulatory asset.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THIS TREATMENT OF UNAMORTIZED DEBT COSTS?

A. As discussed by Mr. Kahal, the OCA is proposing that a determination of Duquesne's stranded costs be made as of December 31, 1998. Consistent with this approach, I am

proposing to recognize the full generation-related balance of unamortized debt costs as of December 31, 1998 as a regulatory asset. Since I am including the balance of these costs entirely as a regulatory asset rather than treating a portion of the costs as being recovered through interest expense, Mr. Kahal has adjusted Duquesne's claimed cost of debt to exclude the recognition of the unamortized debt costs.

Q. WHAT IS THE BALANCE OF REGULATORY ASSETS WHICH YOU ARE PROPOSING TO INCLUDE FOR UNAMORTIZED DEBT COSTS?

A. The balance of unamortized debt costs which I am proposing to recognize as a generation related regulatory asset as of December 31, 1998 is $45.77 million. These costs are eligible to earn a return during the recovery period so that the nominal balance and net present value are the same. I would note that this balance does not include the unamortized debt costs associated with the Beaver Valley 2 sale/leaseback. I have separately accounted for those costs in conjunction with the other costs related to the Beaver Valley 2 sale/leaseback.

Q. HOW DOES YOUR RECOMMENDATION COMPARE TO DUQUESNE'S CLAIMED REGULATORY ASSET?

A. Duquesne has included $29.92 million of unamortized debt costs as a regulatory asset and has recognized an additional $16.76 million of unamortized debt costs as being recovered through interest expense. This total of $46.68 million differs slightly from the regulatory asset which I have identified because the amortization which Duquesne recognized as occurring in 1997 and 1998 is slightly less than the generation percentage of the amortization actually scheduled for those two years.

Beaver Valley 2 Sale/Leaseback

Q. WHAT CLAIM HAS DUQUESNE MADE FOR COSTS RELATED TO THE BEAVER VALLEY 2 SALE/LEASEBACK?

A. Duquesne's claim for costs related to the Beaver Valley 2 (BV2) sale/leaseback is comprised of three separate items: the unamortized balance of the costs incurred in conjunction with the original sale/leaseback; the unamortized balance of the premiums incurred in conjunction with the refinancing of the original lease; and the lease payments themselves. As with unamortized debt costs, the Company has divided these costs into two separate components. The first component consists of the lease payments and amortization which are scheduled for the years 1999 through 2005. Duquesne has included these costs as part of its revenue requirements analysis for those years. The second component relates to the lease payments and amortization scheduled to occur after 2005. Duquesne has included the present value of these costs as regulatory assets.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THE TREATMENT OF THE COSTS ASSOCIATED WITH THE BEAVER VALLEY 2 SALE/LEASEBACK?

A. Consistent with Mr. Kahal's proposal to determine stranded costs as of December 31, 1998, I am calculating the net present value of the lease payments and amortization amounts for 1999 through the end of the lease. In calculating this regulatory asset, the annual lease payments and the amortization amounts for issuance costs and refinancing premiums which I have recognized are the same as those used by Duquesne. I have simply included all of the costs as a regulatory asset rather than dividing the costs into two components as Duquesne has done.

Q. WHAT IS THE AMOUNT OF THE REGULATORY ASSET WHICH YOU DETERMINED FOR THE COSTS ASSOCIATED WITH THE BEAVER VALLEY 2 SALE/LEASEBACK?

A. Based on the Company's proposed discount rate of 7.83 percent, the net present value of the Beaver Valley 2 lease payments and the amortization of the issuance costs and refinancing premium is $539.61 million. At the discount rate of 6.88 percent identified by Mr. Kahal, the net present value of these costs is $577.02 million.

Q. ARE ANY ADJUSTMENTS TO THESE NET PRESENT VALUES NECESSARY?

A. Yes. In calculating the net present value of its Beaver Valley 2 lease payments, Duquesne included additional reductions in the lease obligation of $25 million in 1997 and $38.66 million in 1998.[3] These reductions are intended to reflect the benefits of the Ft. Martin sales agreement which was agreed to in 1996. Consistent with the Company's proposed recognition, I am proposing to reduce the net present value of the Beaver Valley 2 sale/leaseback costs by $63.66 million to reflect these additional reductions. As a result, the regulatory asset which I have identified as attributable to the Beaver Valley 2 sale/leaseback is $475.95 million at the Company's proposed discount rate and $513.36 million at the OCA's discount rate. I would also note that while I have included the present value of the lease payments as a regulatory asset consistent with Mr. Clayton's presentation, Mr. Kahal has treated the present value of the lease as company-owned generation and has transferred the balance from regulatory assets to net plant for purposes of his analysis.

[3]The additional reduction reflected in 1999 has been reduced from $50 million to $38.66 million to reflect an offset for pilot program incentive credits.

Pre-Accrued Nuclear Outage Costs

Q. WHAT HAS DUQUESNE CLAIMED WITH REGARD TO PRE-ACCRUED NUCLEAR OUTAGE COSTS?

A. Duquesne has historically accounted for and been allowed to recover nuclear maintenance outage costs by deferring those costs when incurred and amortizing those costs over the interval between outages. The Company is proposing to revise its accounting treatment of the costs of nuclear maintenance outages so that the costs of an outage are accrued prior to that outage taking place. Consistent with this proposed change in accounting, Duquesne has also proposed to include the pre-accrual of nuclear outage costs as a regulatory asset to be recovered through the CTC.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO DUQUESNE'S CLAIMED REGULATORY ASSET FOR PRE-ACCRUED NUCLEAR OUTAGE COSTS?

A. I am proposing to exclude pre-accrued nuclear outage costs from the balance of regulatory assets. In determining the stranded costs associated with Duquesne's company-owned generating units, my associate, Mr. Kahal, has relied on the cash flow analysis provided by Duquesne which compares projected market revenues to generating unit operating costs. The projected operating costs for the Company's nuclear units include the full cost of the maintenance outages in the years the costs are projected to be incurred. Therefore, there is no need or basis for including a regulatory asset for the pre-accrual of those same costs under the OCA's methodology. To do so would result in double-counting of the costs for which the pre-accrual is made.

Q. IF THE COMMISSION ADOPTS DUQUESNE'S PROPOSED PROCEDURE FOR ADDRESSING STRANDED COSTS, SHOULD PRE-ACCRUED NUCLEAR OUTAGE COSTS BE RECOGNIZED AS A REGULATORY ASSET?

A. No. The historical procedure utilized by Duquesne and approved by the Commission of normalizing nuclear outage costs by deferring and amortizing them over the interval between outages properly matches outage costs to the period to which they apply.[4] Duquesne has not provided any basis for abandoning that practice in favor of pre-accrual and recovery of nuclear maintenance outage costs. Moreover, the Company's revenue requirements analysis for the period 1999-2005 includes a normalized level of outage costs as an expense. Therefore, recognition of the pre-accrued balance of nuclear outage costs which Duquesne proposes to create would result in recovery of more than seven years of outage costs over that seven-year period.

Q. WHAT IS THE EFFECT OF EXCLUDING PRE-ACCRUED NUCLEAR OUTAGE COSTS ON DUQUESNE'S CLAIMED BALANCE OF REGULATORY ASSETS?

A. Excluding pre-accrued nuclear outage costs reduces the nominal balance of regulatory assets as of December 31, 1998 by $22.65 million.[5] As shown in the revised response to OCA Set I, No. 13 (OCA-I-13), this represents the total costs to be incurred during 1999 for the refueling outages at the Company's three nuclear units. As shown in response to OCA-I-21, these same costs have been recognized as operation and maintenance (O&M) cash outlays in 1999.

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[4]The costs of an outage clearly apply to the period following the outage since there are no outage costs when a unit goes into service until the first outage and the last outage will occur prior to the time the unit is retired.

[5]Duquesne did not include these costs in the balance of regulatory assets eligible to earn a return. Hence, the net present value of Duquesne's claim is less than the nominal balance.

Deferred Coal Costs

Q. PLEASE SUMMARIZE DUQUESNE'S CLAIM FOR DEFERRED COAL COSTS.

A. Duquesne has included deferred coal costs in the amount of $13.5 million in its claimed balance of regulatory assets as of December 31, 1998. The balance represents amounts which Duquesne paid for coal in excess of the coal costs which it was permitted to flow through the ECR under the terms of the settlement reached among the parties and approved by the Commission in Docket Nos. P-890386 and P-890387.

Q. WHAT ADJUSTMENT ARE YOU PROPOSING TO MAKE TO THE DEFERRED COAL COSTS CLAIMED BY DUQUESNE?

A. I am proposing to eliminate the balance of deferred coal costs from the balance of regulatory assets eligible for recovery through the CTC. This has the effect of reducing Duquesne's claimed balance of regulatory assets by $13.50 million.

Q. WHY ARE YOU PROPOSING TO EXCLUDE DEFERRED COAL COSTS FROM THE ALLOWABLE BALANCE OF REGULATORY ASSETS?

A. In his direct testimony at page 3, Mr. O'Brien has characterized the Commission approved settlement in Docket Nos. P-890386 and P-890387 as providing for the recovery of all deferred coal costs at some future time. However, that is not the case. The settlement in those dockets allowed the Company to defer costs in excess of a market based price cap for future recovery at such time as its costs were less than the capped price. (Per page A-42 to A-43 of Joint Petition for Settlement, dated April 6, 1990 in Docket Nos. P-890386 and P-890387.) To the extent actual costs did not fall below the market based price cap, the settlement did not provide any other mechanism for the recovery of the deferred costs. In other words, the settlement did not provide assured recovery of any costs which Duquesne was required to defer because the price paid for

coal exceeded the price cap. Therefore, the deferred balance of excess coal costs is not eligible for recovery as a regulatory asset.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING DUQUESNE'S CLAIM FOR DEFERRED COAL COSTS?

A. Yes. Duquesne has treated the balance of deferred coal costs as being eligible to earn a return during the recovery period. The settlement in Docket Nos. P-890386 and P-890387 does not provide for the Company to earn a return on any deferred coal costs. In the event that recovery of these costs was to be granted, the value of the regulatory asset would need to be reduced to recognize the net present value of recovery with no return on the unrecovered balance.

Deferred Caretaker Costs

Q. PLEASE SUMMARIZE DUQUESNE'S CLAIM FOR DEFERRED CARETAKER COSTS.

A. Duquesne has proposed to include the balance of deferred caretaker costs as of December 31, 1998 as a regulatory asset. Deferred caretaker costs represent the costs which the Company has incurred to maintain the Phillips and Brunot Island units during their time in cold reserve. Mr. O'Brien has indicated that the Commission approved recovery of these costs in Docket No. P-900485. The total balance of deferred caretaker costs for which Duquesne has sought recovery as a regulatory asset is $6,770,000.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION WITH REGARD TO DEFERRED CARETAKER COSTS.

A. I am recommending that deferred caretaker costs not be recognized as a regulatory asset. Docket No. P-900485, which Mr. O'Brien cites as providing for the recovery of these costs, was resolved by a settlement agreement which was approved by the Commission.

That settlement allowed Duquesne to defer the costs for preserving the Phillips and Brunot Island units while they were in cold reserve until those units were reactivated. The settlement provided that recovery of the deferred caretaker costs was only to take place at the time the units were returned to service.[6] No provision or assurance was made for recovery of the deferred costs if the units were not returned to service.

In this proceeding, Duquesne is taking the position that the Phillips and Brunot Island units which remain in cold reserve are not expected to be returned to service. Consistent with this position, the Company has not recognized any market revenues from these units to help recover the undepreciated book investment. Because the units are not being returned to service, Duquesne is not entitled to any recovery of the deferred caretaker costs as a regulatory asset.

To the extent that either or both facilities are ever returned to service, it will be because the revenues produced will exceed Duquesne's ongoing costs. If this occurs, then Duquesne will recover its deferred costs from the margins generated. Accordingly, there is no basis for including the deferred caretaker costs as a regulatory asset in this proceeding unless some estimates of the margins which Duquesne would realize are also included.

Q. WHAT IS THE EFFECT OF THIS ADJUSTMENT ON DUQUESNE'S CLAIMED BALANCE OF REGULATORY ASSETS?

[6]At the time of Docket P-900485, it was anticipated that Phillips and Brunot Island would be returned to service in conjunction with a proposed power sale by Duquesne to the GPU companies. Recovery of the investment in Phillips and Brunot Island, including the deferred caretaker costs was to take place through the power sales clause to be implemented in conjunction with the sales. The transaction with GPU was never completed.

A. Excluding deferred caretaker costs reduces Duquesne's claimed balance of regulatory assets by $6.77 million. Duquesne has included these deferred costs in the balance of regulatory assets eligible to earn a return.

SFAS No. 109 Plant Balance

Q. PLEASE EXPLAIN WHAT IS MEANT BY SFAS NO. 109 RECOVERABLE TAXES GENERALLY AND WHAT THE SFAS NO. 109 PLANT BALANCE IS?

A. Pursuant to Statement of Financial Accounting Standards No. 109 (SFAS No. 109), Duquesne is required to record its future tax liabilities on its balance sheet. One component of this future tax liability is the future tax obligation associated with tax-book timing for which the benefits have been flowed through to ratepayers. Duquesne has identified this as its "regulatory tax receivable." A second component of this future tax liability relates to the differences between the costs capitalized as part of plant costs for book purposes and tax purposes (basis differences). This component is primarily attributable to the fact that the allowance for funds used during construction (AFUDC) on Duquesne's nuclear units was recorded on a net of tax basis. Duquesne has identified this future tax liability as "SFAS No. 109 plant."

Q. WHAT ADJUSTMENT ARE YOU PROPOSING WITH REGARD TO THE BALANCE OF SFAS NO. 109 PLANT?

A. At the time Duquesne adopted SFAS No. 109, it recorded the future tax liability associated with plant basis differences as an increase in the plant balances for its nuclear generating units. For purposes of its presentation in this proceeding, Duquesne removed the SFAS No. 109 plant tax liability from the balance of plant in service as of January 1, 1999 and included this balance as a regulatory asset. This was necessary to provide for

the recovery of the cost during the CTC period based on the Company's proposed procedure for addressing stranded costs.

For purposes of the OCA's analysis, I have removed the SFAS No. 109 plant balance from the balance of regulatory assets. This is necessary because the SFAS No. 109 plant tax liability is included in the plant balances associated with the Company's nuclear generating units as of December 31, 1998. Since Mr. Kahal is utilizing the plant balances as of December 31, 1998 to determine stranded costs, he has already accounted for the SFAS No. 109 plant tax liability in his analysis and it is unnecessary to also include this balance as a regulatory asset.

Q. WHAT IS THE EFFECT OF YOUR ADJUSTMENT ON THE BALANCE OF REGULATORY ASSETS?

A. Removing the SFAS No. 109 plant balance reduces the balance of regulatory assets claimed by Duquesne by $62.94 million. Duquesne treated this balance as eligible to earn a return during the recovery period.

Q. DO YOU HAVE ANY OTHER COMMENTS WITH REGARD TO SFAS NO. 109 RECOVERABLE TAXES?

A. Yes. In the restructuring cases of several of the other Pennsylvania electric utilities (e.g., PECO, Met-Ed, Penelec, West Penn), I have identified an issue regarding the claimed regulatory asset for SFAS No. 109 recoverable taxes. This issue relates to the fact that these companies have claimed the nominal balance of SFAS No. 109 recoverable taxes as a regulatory asset rather than valuing the regulatory asset at the net present value of the revenue stream which the Company would have received under traditional regulation. The procedure which Duquesne has used to account for SFAS No. 109 recoverable taxes properly results in only the net present value of the SFAS No. 109 recoverable taxes being included as a stranded cost.

Nuclear Decommissioning Costs

Q. PLEASE EXPLAIN DUQUESNE'S CLAIM FOR NUCLEAR DECOMMISSIONING COSTS.

A. Consistent with its approach of calculating the remaining stranded costs as of December 31, 2005, Duquesne has recognized nuclear decommissioning costs as an offset to the market value of its generating units as of that date. To accomplish this, Duquesne escalated the current estimates of decommissioning costs for Beaver Valley 1, Beaver Valley 2 and Perry to projected price levels at the time those costs are expected to be incurred using a 4.0 percent per year escalation rate. It then calculated the nuclear decommissioning trust fund balance which would need to exist as of December 31, 2005 in order to fund these future costs assuming that trust fund earnings would equal 7.5 percent per year. Next, the Company calculated the projected trust fund balance which would exist at December 31, 2005 based on maintaining the current level of funding contributions and including earnings at 7.5 percent per year. Finally, Duquesne compared the projected trust fund balances with the required balances for each unit at December 31, 2005 to determine the offset to market value.

Q. WHAT CHANGE ARE YOU PROPOSING TO MAKE TO THE TREATMENT OF NUCLEAR DECOMMISSIONING COSTS?

A. I am proposing to change the treatment of nuclear decommissioning expenses to be consistent with the OCA's proposal to determine stranded costs as of December 31, 1998 rather than December 31, 2005. To accomplish this, I have calculated the annual funding contributions which are required over the years 1999 to 2005 to fully fund nuclear decommissioning costs prior to December 31, 2005.

Q. IN MAKING YOUR CALCULATION, HAVE YOU MADE ANY ADJUSTMENTS TO THE COMPANY'S ESTIMATES OF DECOMMISSIONING COSTS?

A. Yes. The Company's estimates of decommissioning costs for Beaver Valley 1, Beaver Valley 2 and Perry include allowances for contingencies of 21.70 percent, 21.74 percent and 16.71 percent, respectively. I am proposing to adjust the Company's cost estimates to reflect an allowance for contingencies of ten percent.

Q. WHAT PRECEDENT EXISTS FOR REDUCING THE ALLOWANCE FOR CONTINGENCIES TO TEN PERCENT?

A. In its Order in Pennsylvania Power & Light Company's last rate case at Docket No. R-00943271, the Commission eliminated the contingencies built into that company's nuclear decommissioning cost estimates in their entirety. In doing so, the Commission noted that there is no reason to conclude "... that speculative future costs necessitate a large contingency factor which rests, in itself, on estimated costs which are far from certain." (p. 82) More recently, in July 1996, the Commission issued a *Proposed Policy Statement Regarding Nuclear Decommissioning Cost Estimation and Cost Recovery* which stated that: "Cost estimates may not include more than a 10% overall contingency factor ..." While a lower contingency factor could be supported, I have reflected an allowance for contingencies at the upper end of the range suggested by the Commission.

Q. ARE YOU PROPOSING ANY OTHER CHANGES TO DUQUESNE'S FUNDING ASSUMPTIONS FOR PURPOSES OF YOUR CALCULATIONS?

A. No. I have adopted the Company's assumptions that nuclear decommissioning costs will escalate at the rate of 4.0 percent per year and that the earnings rate on the decommissioning trust funds will average 7.5 percent per year. In addition, in its calculations of decommissioning funding requirements, Duquesne has properly

recognized the timing of the decommissioning expenditures. That is, the Company has recognized both that inflation will continue to affect decommissioning costs during the period over which decommissioning takes place and that the unexpended balance of the trust funds will continue to earn a return during that same period. I have carried these procedures over to my analysis of funding requirements, as well.

Q. HAVE YOU PREPARED A SCHEDULE SHOWING THE REQUIRED DECOMMISSIONING FUNDING CONTRIBUTIONS FOR DUQUESNE'S SHARE OF THE BEAVER VALLEY 1, BEAVER VALLEY 2 AND PERRY NUCLEAR GENERATING STATIONS?

A. Yes. Schedule TSC-2 presents the decommissioning funding calculations for each of Duquesne's nuclear units. Page 1 of this schedule summarizes my findings and pages 2 through 4 show the funding requirements for Beaver Valley 1, Beaver Valley 2 and Perry, respectively. For each unit, I have calculated the annual contributions required to fully fund the decommissioning costs over the seven-year period the CTC is expected to be in effect. As shown on page 1 of Schedule TSC-2, the total funding requirements for the three units are $7,949,000 per year.

Fossil Decommissioning Costs

Q. HOW HAS DUQUESNE TREATED FOSSIL DECOMMISSIONING COSTS IN DEVELOPING ITS STRANDED COST CLAIM?

A. Duquesne has included fossil decommissioning costs as a stranded cost by deducting the present value of the claimed decommissioning liability from the estimated market value of its generating units as of December 31, 2005. To determine the present value of its decommissioning liability, the Company escalated the current estimate of decommissioning costs for each fossil plant to the projected price levels at the time those

costs are expected to be incurred. For purposes of determining stranded costs, the costs of decommissioning each unit were assumed to be incurred beginning in the year of that unit's retirement and extending over the projected time period required to complete the decommissioning process. Next, Duquesne assumed that each year's costs would be amortized and recovered over five years. Finally, these projected future annual amortizations were discounted back to their net present value as of December 31, 2005 to obtain the liability to be deducted from market value.

Q. DO YOU AGREE WITH DUQUESNE'S CLAIM FOR FOSSIL DECOMMISSIONING COSTS?

A. No. Fossil decommissioning costs should not be included in the determination of stranded costs for several reasons. First, it is common practice to leave the generating units in place while the site continues to be used as the location for additional generating units. In addition, generating facilities are often reconditioned, repowered, or reconstructed because of the value and benefits from continuing to use the site, the infrastructure and as much of the existing facilities as possible. As a result, there is a great deal of uncertainty as to whether dismantling and decommissioning of Duquesne's existing generating facilities will occur and, if so, when.

Second, even if dismantling and decommissioning of the existing generating units at a site takes place as anticipated, existing generation sites are generally quite valuable. This stems from the value of the existing site as the location for a new generating facility due to the existence of all of the necessary infrastructure, including access to the transmission grid. If the site is not used as the location for a new generating facility, the land is apt to be valuable for other purposes. The value of the site will serve to offset some, if not all of the decommissioning costs.

Finally, the costs of decommissioning a generating unit are not unique to regulated utilities such as Duquesne. To the extent owners of generating facilities are required to and do decommission their fossil generating units, the costs will have to be borne by Duquesne's competitors as well as by Duquesne. Mr. Doug Smith, who is developing the OCA's market price projections, has indicated that those projections assume that the fossil decommissioning costs to be incurred by Duquesne's future competitors must be borne by the generating units' owners out of the market revenues which are received. Accordingly, it would be inappropriate to require ratepayers to fund Duquesne's fossil decommissioning costs in advance when competitors in the generation market will have to derive any necessary decommissioning funds through market prices paid for their power.

Q. IF THE COMMISSION DECIDES TO RECOGNIZE FOSSIL DECOMMISSIONING COSTS, ARE ANY ADJUSTMENTS TO THE COMPANY'S CLAIM FOR STRANDED COSTS NECESSARY?

A. Yes, if fossil decommissioning costs are to be recognized in the determination of stranded costs, two adjustments should be made to the Company's computations. First, Duquesne's cost estimates for decommissioning its fossil fueled generating units include contingency factors of approximately 15 percent. Consistent with the Commission's July 1996 *Proposed Policy Statement Regarding Nuclear Decommissioning Cost Estimation and Cost Recovery,* the contingency included in fossil decommissioning costs should be limited to no more than ten percent.

Second, Mr. Kahal has recommended life extensions for several of Duquesne's coal-fired generating facilities. Any allowance for fossil decommissioning costs should take those longer lives into consideration in determining the net present value of the future expenditures. In addition, the inflation rate used to escalate fossil decommissioning costs

to future price levels and the discount rate used to calculate the net present value of those future costs should be consistent with the overall inflation and discount rates adopted by the Commission for purposes of determining stranded costs.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does. As noted previously, however, I have included Duquesne's claimed transition costs in my determination of regulatory assets pending the receipt of additional discovery responses. After reviewing that data, I may revise my recommendation at the time I submit surrebuttal testimony.

ATTACHMENT A

THOMAS S. CATLIN

Mr. Catlin is a principal in Exeter Associates, Inc. He is a senior utility rate analyst with a combination management and analytical background. His areas of specialization are revenue requirements and cost of service.

Mr. Catlin has extensive experience in the review and analysis of the operations of public utilities. The emphasis of this work has been on utility rate regulation and has involved telephone, natural gas, electric and water companies. He is familiar with all aspects of utility ratemaking, the use of economic and engineering analytical techniques, rate base and operating income determination, income taxes, and utility accounting. Mr. Catlin has provided expert testimony before the Arizona, California, Colorado, Delaware, District of Columbia, Florida, Idaho, Illinois, Indiana, Kentucky, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Utah, Virginia and West Virginia public utility commissions as well as before the Federal Energy Regulatory Commission. This testimony has addressed all aspects of utility regulation including revenue requirements, cost of service, and rate design. Mr. Catlin has also been responsible for conducting cost of service, rate, and financial studies involving municipal and investor-owned water, wastewater, and storm drainage utilities.

Education:

B.S. (Physics with minor in Math) - State University of New York at Stony Brook, 1974.

M.S. (Water Resources Engineering & Management) - Arizona State University, 1976.

Graduate courses in Accounting - Suffolk University, 1978-79.

Previous Employment:

1978-1981	Utility Rates Specialist, Camp Dresser & McKee, Inc.
1977-1978	Engineer, Camp Dresser & McKee, Inc.
1976-1977	Engineer, Arthur Beard Engineers, Inc.

Professional Work:

Mr. Catlin has participated in rate cases for telephone, natural gas, electric and water utilities. This work has included the review, analysis and presentation of expert testimony regarding all aspects of revenue requirements including rate base, revenues, expenses, and income taxes. This work has also involved conducting and testifying on marginal and embedded cost studies and rate design. In the natural gas area, Mr. Catlin has been involved in conducting management audits and similar reviews of the gas supply and procurement policies and practices of natural gas distribution companies. His work in this area has also addressed minimum bill issues and take or pay cost recovery, as well as the review of PGA filings at both the state and federal level. In the telecommunications area, Mr. Catlin has conducted and testified with regard to cost of service and rate design studies and analyses for a variety of both monopoly and competitive services. This has included the issue of carrier and subscriber access charges. In addition to providing testimony and assisting in the litigation of rate cases, Mr. Catlin has also been involved in negotiating settlements of a number of cases.

At Camp Dresser & McKee, Inc., Mr. Catlin was a project manager for utility rates, financial, and economic studies. He performed studies on approximately 15 municipal and private water, wastewater and storm drainage utilities. His assignments involved: determining the total costs of service; developing capital asset and depreciation bases; preparing cost allocation studies; evaluating alternative rate structures and designing rates; bill analyses; cost and revenue projections; preparing rate filings; and expert testimony.

Prior to transferring to the Camp Dresser & McKee's management service group, Mr. Catlin was an environmental engineer with CDM. He was involved in both project administration and design. Project administration and control responsibilities included budget preparation, labor and cost monitoring and forecasting, and contract preparation.

At Arthur Beard Engineers, Inc., Mr. Catlin served as project coordinator for a major environmental impact statement. He also served as project engineer for a county-wide water supply study and two utility valuation studies.

Publications:

"Effects of Pricing Policy on Residential Water Use," Masters Degree research paper, Arizona State University, 1976.

"Water Rate Policy," presented to Water Resources Policy Committee of California Section of AWWA, 1977.

"Try Capacity Charges to Generate Water Utility Capital," American City and County, February 1981.

"Rate Structure Alternative for Utilities," with John J. Gall, Public Works Magazine, June 1982.

"A First Look at the Effect of the Tax Reform Act of 1986 on Public Utility Ratemaking," with Matthew I. Kahal, October 1986.

"State Implementation of the Tax Reform Act Changes," presented to the National Association of State Utility Consumer Advocates, November 1986.

"Three Ratemaking Issues Arising from The Tax Reform Act of 1986," presented to the National Association of State Utility Consumer Advocates, November 1987.

"SFAS No. 106 and Public Utility Ratemaking," with Randy M. Allen, May 1991.

Prior Expert Testimony

of Thomas S. Catlin

Before State Commissions:

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket 1513), February 1981. Testified on revenue requirements, cost of service and rate design on behalf of the Providence Water Supply Board.

Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket RID 1819), April & May 1982. Testified on cost analyses and rate design on behalf of the Office of Consumer Advocate.

Washington Gas Light Company (Maryland Public Service Commission, Case No. 7649), October 1982. Testified on cost of service issues on behalf of the Maryland People's Counsel.

Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket R-832316), August 1983. Testified on cost analyses and rate design on behalf of the Office of Consumer Advocate.

Chesapeake & Potomac Telephone Company (D.C. Public Service Commission, Formal Case No. 798), October 1983. Testified on cost of service on behalf of the Public Service Commission Staff.

Columbia Gas of Pennsylvania (Pennsylvania Public Utility Commission, Docket R-832493), April 1984. Testified on revenue, expense, and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Generic Investigation Concerning Intrastate Access Charges (Pennsylvania Public Utility Commission, Docket P-830452), August 1984. Testified on telephone access service costs and subscriber access charge issues on behalf of the Pennsylvania Office of Consumer Advocate.

Gulf Power Company (Florida Public Service Commission, Docket 840086-EI), August 1984. Testified on rate base issues on behalf of the Federal Executive Agencies.

Western Pennsylvania Water Company (Pennsylvania Public Utility Commission, Docket R-842621, et al.), August 1984. Testified on revenue, expense, rate base, and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

ALLTEL Pennsylvania (Pennsylvania Public Utility Commission, Docket R-842710), January 1985. Testified on revenue, expense, rate base and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Chesapeake & Potomac Telephone Company (D.C. Public Service Commission, Formal Case No. 827), March 1985. Testified on cost of service matters on behalf of the Office of People's Counsel.

Chesapeake & Potomac Telephone Company (Maryland Public Service Commission, Case No. 7851), March 1985. Testified on cost of service matters on behalf of the Public Service Commission Staff.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-842632), March 1985. Testified on rate base, expense and income tax issues on behalf of the Office of Consumer Advocate.

New England Telephone and Telegraph Company (Rhode Island Public Utilities Commission, Consolidated Docket 1560(R), 1631, 1654), April 1985. Testified on category cost of service and service cost matters on behalf of the Division of Public Utilities and Carriers.

Chesapeake & Potomac Telephone Company (West Virginia Public Service Commission, Case No. 84-747-T-42T), June 1985. Testified on rate base and expense issues, impacts of divestiture, and separations issues on behalf of the Public Service Commission, Consumer Advocate Division.

Oklahoma Gas & Electric Company (Oklahoma Corporation Commission, Cause No. 29450), July 1985. Testified on rate base, operating income and income tax issues on behalf of the Attorney General.

Bristol County Water Company (Rhode Island Public Utilities Commission, Docket No. 1811), August 1985. Testified on rate base, operating income and income tax issues on behalf of the Division of Public Utilities and Carriers.

Continental Telephone Company of Pennsylvania and Quaker State Telephone Company (Pennsylvania Public Utility Commission, Docket Nos. R-850044 and R-850045, Consolidated hearings), September 1985. Testified on rate base, toll revenue, expense and income tax matters on behalf of the Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-850174), November 1985. Testified on rate base, revenue, expense and income tax issues on behalf of the Office of Consumer Advocate.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-850220), January 1986. Testified on rate base and net operating income issues on behalf of the Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-860296), March 1986. Testified regarding purchased gas costs and cost recovery on behalf of the Office of Consumer Advocate.

Idaho Power Company (Idaho Public Utilities Commission, Case No. U-1006-265), April 1986. Testified on rate base, operating expense, and income tax matters on behalf of the Federal Executive Agencies.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-850287), July 1986. Testified regarding rate base, revenue, expense, and income tax issues on behalf of the Office of Consumer Advocate.

Dauphin Consolidated Water Supply Company (Pennsylvania Public Utility Commission, Docket No. R-860350), July 7, 1986. Testified in rate base, operating revenue and expense, and income tax issues on behalf of the Office of Consumer Advocate.

Blackstone Valley Electric Company (Rhode Island Public Utilities Commission, Docket No. 1849), August 1986. Testified on rate base, revenue, expense and income tax issues on behalf of the Division of Public Utilities and Carriers.

Dayton Power and Light Company (Public Utilities Commission of Ohio, Case No. 86-17-GA-GCR), August 1986. Testified regarding audit of management and performance of gas purchasing policies and practices on behalf of the Public Utilities Commission of Ohio.

West Virginia Water Company (West Virginia Public Service Commission, Case No. 86-212-W-42T), October 1986. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division. (Case settled prior to cross-examination.)

Prior Expert Testimony

of Thomas S. Catlin

Kentucky West Virginia Gas Company (Federal Energy Regulatory Commission, Docket No. RP86-52-000), November 1986. Testified on elimination of the minimum bill and take or pay exposure on behalf of the Pennsylvania Office of Consumer Advocate.

Huntington Water Corporation (West Virginia Public Service Commission, Case No. 86-341-W-42T), December 1986. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division. (Case settled prior to cross-examination.)

Louisiana Power and Light Company (Louisiana Public Service Commission, Docket No. 16945), December 1986. Testified on rate base, revenue, expense, income tax and phase-in issues on behalf of the Staff of the Commission.

Mountain States Telephone and Telegraph Company (Colorado Public Utilities Commission, Docket No. 1720), December 1986. Testified on the measurement of dial tone or access line costs and separations procedures on behalf of the Colorado Office of Consumer Counsel.

Columbia Gas Transmission Corporation (Federal Energy Regulatory Commission, Docket No. RP86-168-000), April 1987. Testified on rate base, operating income, and income taxes on behalf of the Commonwealth of Pennsylvania Office of Consumer Advocate.

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission, Docket No. RP87-7-000), May 1987. Testified on appropriate regulatory treatment of surplus proceeds resulting from termination of pension plan on behalf of the Pennsylvania Office of Consumer Advocate.

Monongahela Power Company (West Virginia Public Service Commission, Case No. 86-524-E-SC), May 1987. Testified on rate base and operating income issues on behalf of the Public Service Commission, Consumer Advocate Division.

Atlantic City Sewerage Company (New Jersey Board of Public Utilities, Docket No. WO 8606654), June and August 1987. Presented testimony on behalf of Resorts International, Inc., addressing responsibility of Company to pay cost of extending facilities.

Newport Electric Corporation (Rhode Island Public Utilities Commission, Docket No. 1872), July 1987. Testified on rate base and operating income issues, including the effects of the Tax Reform Act of 1986 on behalf of the Division of Public Utilities and Carriers.

Prior Expert Testimony

of Thomas S. Catlin

General Telephone of the South (West Virginia Public Service Commission, Case No. 86-870-T-42T), July 1987. Testified on rate base, operating income and jurisdictional separations issues on behalf of the Consumer Advocate Division of the Public Service Commission. (Case settled prior to cross-examination.)

Philadelphia Electric Company-Gas Operations (Pennsylvania Public Utility Commission, Docket No. R-870629), August 1987. Testified on operating income and income tax matters on behalf of the Office of Consumer Advocate.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-850220 Reconsideration), August 1987. Testified on issue of retroactive ratemaking and revenue requirement effects of alternative excess capacity adjustments recommended by others on behalf of Pennsylvania Office of Consumer Advocate.

Dauphin Consolidated Water Supply Company (Pennsylvania Public Utility Commission, Docket No. R-860350 Reconsideration), September 1987. Testified on recognition of proper balance of deferred income taxes collected from ratepayers on behalf of Pennsylvania Office of Consumer Advocate.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio Case No. 87-29-GA-GCR), October 1987. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

GTE North, Inc. (Pennsylvania Public Utility Commission, Docket No. M-860105, F. 18), November 1987. Testified on effects of Tax Reform Act of 1986 on behalf of Pennsylvania Office of Consumer Advocate.

Panhandle Eastern Pipe Line Company (Federal Energy Regulatory Commission, Docket No. RP87-103-000), February 1988. Testified on rate base, operating income and income tax issues on behalf of Indiana Office of Utility Consumer Counselor.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-870840), February 1988. Testified on revenue, expense, income tax, and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Sierra Pacific Power Company-Water Department (Nevada Public Service Commission, Docket No. 87-1226), April 1988. Testified on cost of service allocation on behalf of the Nevada Office of Consumer Advocate.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. FA86-19-001), April 1988. Testified regarding cost of service tariff (formula rate) issues on behalf of the Louisiana Public Service Commission.

The Peoples Natural Gas Company (Pennsylvania Public Utilities Commission Docket No. R-880961), August 1988. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Louisiana Power and Light Company (Louisiana Public Service Commission Docket No. U-17906), September 1988. Testified on operating income and rate making policy issues on behalf of the Staff of the Commission.

National Gas and Oil Corporation (Public Utilities Commission of Ohio Case No. 88-22-GA-GCR), September 1988. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination).

Columbia Gas of Ohio, Inc. (Public Utilities Commission of Ohio Case No. 88-24-GA-GCR), October 1988. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination).

Providence Gas Company (Rhode Island Public Utilities Commission Docket No. 1914), December 1988. Testified on operating income and regulatory policy issues on behalf of the Division of Public Utilities and Carriers.

Kentucky-West Virginia Gas Company (Federal Energy Regulatory Commission Docket No. RP86-52-000), February 1989. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-881125), March 1989. Testified on purchased gas costs and take-or-pay cost recovery on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Chesapeake Utilities Corporation (Maryland Public Service Commission Case No. 8154), April 1989. Testified on take-or-pay cost recovery on behalf of Maryland People's Counsel.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission Docket No. R-891208), May 1989. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Peoples Natural Gas Company (Pennsylvania Public Utility Commission Docket No. R-891232), May 1989. Testified on purchased gas costs and take-or-pay cost recovery on behalf of the Pennsylvania Office of Consumer Advocate.

Maryland Natural Gas and Frederick Gas Company, Inc. (Maryland Public Service Commission Case Nos. 8153 and 8155), May 1989. Testified on take-or-pay cost recovery on behalf of Maryland People's Counsel.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-891218), July 1989. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

The River Gas Company (Public Utilities Commission of Ohio Case No. 89-31-GA-GCR), August 1989. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination.)

Central Maine Power Company (Maine Public Utilities Commission Docket No. 89-68), August 1989. Testified on revenue, expense, rate base and income tax issues, as well as selection of proper test year on behalf of the Maine Public Advocate.

Public Service of Indiana, Inc. (Indiana Utility Regulatory Commission Cause No. 37414-S2), October 1989. Testified on rate base, net operating income, and accounting issues on behalf of the Indiana Utility Consumer Counselor.

National Fuel Gas Supply Corporation (Federal Energy Regulatory Commission Docket No. RP89-49-000), December 1989 and February 1990. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

System Energy Resources, Inc. (Federal Energy Regulatory Commission), February 1990. Testified on one-eighth formula working capital requirement on behalf of the Louisiana Public Service Commission.

Bangor Hydro-Electric Company (Maine Public Utilities Commission Docket No. 90-001), June 1990. Testified on rate base revenues, expenses, sales forecasts and attrition on behalf of the Maine Public Advocate.

Mountain Fuel Supply Company (Utah Public Service Commission Docket No. 89-057-15), July 1990. Co-sponsored testimony regarding natural gas procurement practices and policies.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission Docket No. R-901670), July 1990. Testified on revenue, expense and income tax issues on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company Water Department (Nevada Public Service Commission Docket No. 90-524), September 1990. Testified on class cost of service issues on behalf of the Nevada Office of Consumer Advocate.

Central Maine Power Company (Maine Public Utilities Commission Docket No 90-076), September 1990. Testified on test year rate base, revenue and expense issues and on attrition on behalf of the Maine Public Advocate.

South Central Bell Telephone Company (Louisiana Public Service Commission Docket No. U-17949), October 1990. Testified on operating income issues and attrition on behalf of the Louisiana Public Service Commission.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. ER89-678-000), November 1990. Testified on decommissioning funding issues on behalf of the Louisiana Public Service Commission.

Columbia Gas of Ohio (Public Utilities Commission of Ohio, Case No. 91-16-GA-GCR), November 1990. Co-authored report on audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without cross-examination).

Prior Expert Testimony

of Thomas S. Catlin

South Central Bell vs. Louisiana Public Service Commission (Nineteenth Judicial District Court, Parish of East Baton Rouge, Louisiana, Docket No. 333, 273), November 1990. Testified on overearnings of South Central Bell on behalf of the Louisiana Public Service Commission.

New Jersey Natural Gas Company (New Jersey Board of Public Utilities Docket No. GR90080786J), January 1991. Testified on cash working capital and storage inventory on behalf of the New Jersey Public Advocate.

Nevada Power Company (Nevada Public Service Commission Docket No. 90-1037), February 1991. Testified on deferred fuel cost and accounting issues on behalf of the U.S. Department of Energy.

City of Great Falls Wastewater Utility (Montana Public Service Commission Docket No. 90.10.66), March 1991. Testified on cost allocation issues on behalf of the U.S. Air Force.

City of Great Falls Water Utility (Montana Public Service Commission Docket No. 90.10.67), March 1991. Testified on cost allocation issues on behalf of the U.S. Air Force.

Duquesne Light Company, Metropolitan Edison Company and Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket Nos. P-900485, P-910502 and G-900240), May 1991. Testified on behalf of the Pennsylvania Office of Consumer Advocate regarding accounting and regulatory issues in regard to the reactivation of a generating station and the transfer/sale of assets.

Bangor Hydro Electric Company (Maine Public Utilities Commission Docket No. 91-010), June 1991. Testified on test year revenue, expense and rate base and attrition issues on behalf of the Maine Public Advocate.

System Energy Resources, Inc. (Federal Energy Regulatory Commission Docket No. FA89-28-000), June 1991. Testified regarding proper accounting for fees associated with the sales of accounts receivable on behalf of the Louisiana Public Service Commission.

Wakefield Water Company (Rhode Island Public Utilities Commission Docket No. 2006), July 1991. Testified regarding revenue requirements, cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

Prior Expert Testimony

of Thomas S. Catlin

UGI Corporation (Pennsylvania Public Utility Commission Docket No. R-911973), July 1991. Testified on purchased gas costs on behalf of the Pennsylvania Office of Consumer Advocate.

Nevada Power Company (Nevada Public Service Commission Docket No. 91-5055), September 1991. Testified on rate base and net income issues on behalf of U.S. Department of Energy.

Arkansas Louisiana Gas Company (Louisiana Public Service Commission Docket No. U-19236), October 1991. Testified on rate adjustment mechanisms, private line replacement, rate design and postretirement benefits on behalf of the Staff of the Commission.

Cincinnati Gas & Electric Company (Public Utilities Commission of Ohio, Case No. 91-16-GA-GCR), October 1991. Co-authored report on the audit of management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

Sierra Pacific Power Company (Nevada Public Service Commission, Docket Nos. 91-7079, 91-7080 and 91-7081), November 1991. Testified on consolidated income taxes and construction work in progress on behalf of the Nevada Office of Consumer Advocate.

Sierra Pacific Power Company (Nevada Public Service Commission, Docket No. 91-7081), December 1991. Testified on water cost allocation and rate design issues on behalf of the Nevada Office of Consumer Advocate.

Louisiana Gas Service Company (Louisiana Public Service Commission, Docket No. U-19237), December 1991. Testified on test year net income, rate base and attrition issues on behalf of the Staff of the Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 2022), January 1992. Testified on matters pertaining to a proposed surcharge on behalf of the Division of Public Utilities and Carriers.

South Jersey Gas Company (New Jersey Board of Regulatory Commissioners, Docket No. GR91071243J), January and February 1992. Testified on rate base, operating income, and income tax issues on behalf of New Jersey Rate Counsel.

Prior Expert Testimony

of Thomas S. Catlin

Newport Water Division (Rhode Island Public Utilities Commission, Docket No. 2029), February 1992. Testified on cost allocation and rate design matters on behalf of the Division of Public Utilities and Carriers.

Equitable Gas Company (Pennsylvania Public Utility Commission, Docket No. R-00912164), April 1992. Testified on rate base and net operating income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Mountain Fuel Supply Company (Utah Public Service Commission, Docket Nos. 91-057-11 & 15), May 1992. Testified on gas procurement and gas cost issues on behalf of the Utah Committee of Consumer Services.

Trans Louisiana Gas Company (Louisiana Public Service Commission, Docket No. U-19631) June 1992. Testified on rate adjustment mechanisms, rate design and postretirement benefits on behalf of the Staff of the Commission.

Artesian Water Company, Inc. (Delaware Public Service Commission, Docket No. 92-5), June 1992. Testified on cost allocation and rate design issues on behalf of the Staff of the Commission.

Providence Water Supply Board (Rhode Island Public Utilities Commission Docket No. 2048), August 1992. Testified on revenue requirements, cost allocation policy and rate design issues on behalf of the Division of Public Utilities and Carriers.

US West Communications, Inc. (Utah Public Service Commission, Docket No. 92-049-05), August and October 1992. Testified on proper ratemaking treatment of postretirement benefits expense on behalf of Utah Committee of Consumer Services.

Dallas Water Company et al. (Pennsylvania Public Utility Commission, Docket No. R-00922326 et al.), September 1992. Testified on revenue requirements and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

Generic Investigation into Treatment of Postretirement Benefits Expense (Utah Public Service Commission, Docket No. 92-999-04), October 1992. Testified on proper ratemaking treatment of postretirement benefits expense on behalf of Utah Committee of Consumer Services.

Prior Expert Testimony

of Thomas S. Catlin

Commonwealth Gas Services, Inc. (Virginia Corporation Commission, Case No. PUE920037), October 1992. Testified on revenue, cash working capital, weather normalization and post in service carrying charges on behalf of the Division of Consumer Counsel of the Office of Attorney General.

Entergy Corporation and Gulf States Utilities (Louisiana Public Service Commission, Docket No. U-19904), November 1992. Testified on merger related issues on behalf of the Louisiana Public Service Commission Staff.

West Penn Power Company (Pennsylvania Public Utility Commission, Docket No. R-00922378), December 1992. Testified on rate base and net operating income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Columbia Gas of Ohio (Public Utilities Commission of Ohio, Case No. 92-18-GA-GCR), January 1993. Coauthored report on the audit of management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

Bossier Rural Electric Membership Cooperative (Louisiana Public Service Commission, Docket No. U-19944), February 1993. Testified on prudence standards applicable to utility decision making on behalf of the Staff of the Commission.

Consideration of Statement of Financial Accounting Standard No. 106 (Louisiana Public Service Commission, Docket No. U-20181), February 1993. Testified on regulatory issues related to adoption of SFAS No. 106 for ratemaking on behalf of the Staff of the Commission.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00922476), March 1993. Testified on rate base and net income issues on behalf of the Pennsylvania Office of Consumer Advocate.

Sierra Pacific Power Company Water Department (Nevada Public Service Commission, Docket No. 92-121022), April 1993. Testified on class cost of service and rate design on behalf of the Nevada Office of Consumer Advocate. (Case settled prior to cross examination.)

Central Maine Power Company (Maine Public Utilities Commission, Docket No. 92-345), May 1993. Testified on test year net income and rate base and attrition issues on behalf of the Staff of the Maine PUC.

Prior Expert Testimony

of Thomas S. Catlin

Dauphin Consolidated Water Supply Company and General Waterworks of Pennsylvania, Inc. (Pennsylvania Public Utility Commission, Docket No. R-00932604), June 1993. Testified on rate base, income tax and class cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Kent County Water Authority (Rhode Island Public Utilities Commission, Docket No. 2098), July 1993. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Supply Corporation (Federal Energy Regulatory Commission, Docket No. RP92-73-000), July 1993. Testified on rate base and revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

City of Woonsocket Water Department (Rhode Island Public Utilities Commission, Docket No. 2099), July 1993. Testified on cost allocation and rate design issues on behalf of the Division of Public Utilities and Carriers.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-00932548), July 1993. Testified on income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

Conestoga Telephone & Telegraph Company (Pennsylvania Public Utility Commission Docket No. I-00920015), September 1993. Testified on revenue expense and rate base issues as well as proper average schedule separations procedures on behalf of the Pennsylvania Office of Consumer Advocate.

The Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 93-14-GA-GCR), October 1993. Co-authored report on the audit of management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to and accepted without cross-examination.)

The Bell Telephone Company of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. P-00930715), December 1993. Testified on historical and projected earnings levels and earnings monitoring in conjunction with alternative regulatory plan on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00932670), February 1994. Testified on class cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

Philadelphia Suburban Water Company (Pennsylvania Public Utility Commission, Docket No. R-00932868), April 1994. Testified on class cost of service and rate design on behalf of the Pennsylvania Office of Consumer Advocate.

Southwest Gas Corporation - Southern Arizona Division (Arizona Corporation Commission, Docket No. U-1551-93-272), May 1994. Testified on revenue and rate base issues on behalf of the Staff of the Arizona Corporation Commission. (Case settled prior to cross-examination)

Commonwealth Edison Company (Illinois Commerce Commission, Docket No. 94-0065), June 1994. Testified on nuclear decommissioning funding on behalf of the U.S. Department of Energy.

West Penn Power Company (Pennsylvania Public Utility Commission Docket R-00942986), July 1994. Testified on net income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

City of Bethlehem-Bureau of Water (Pennsylvania Public Utility Commission, Docket No. R-00943124), October 1994. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

General Waterworks of Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00943152), October 1994. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Gas & Oil Corporation (Public Utilities Commission of Ohio, Case No. 94-221-GA-GCR), October 1994. Co-authored report on the audit of the management and performance of gas purchasing on behalf of Public Utilities Commission of Ohio. (Findings and recommendations were stipulated to without hearings.)

Trans Louisiana Gas Company (Louisiana Public Service Commission, Docket No. U-19997), November 1994. Testified on the costs properly included in the weighted average cost of gas of Louisiana Intrastate Gas Corporation and the purchased gas adjustment of Trans La on behalf of Staff of the Commission.

Prior Expert Testimony

of Thomas S. Catlin

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket Nos. RP91-203-000 and RP92-132-000, Phase II-PCB Issues), December 1993. Testified on cost of PCB remediation in current dollars and percentage allowance applicable to claimed PCB costs on behalf of the Pennsylvania Office of Consumer Advocate and the Ohio Office of the Consumer's Counsel. (Case settled prior to cross-examination.)

New England Telephone and Telegraph Company (Maine Public Utilities Commission, Docket Nos. 94-123 and 94-254), December 1994. Testified on Process Re-engineering (downsizing) costs and benefits and on attrition issues on behalf of the Maine Public Advocate.

Louisiana Power & Light Company (Louisiana Public Service Commission, Docket No. U-20925), February 1995. Testified on rate base and operating income on behalf of the Staff of the Public Service Commission.

Pennsylvania-American Water Company (Pennsylvania Public Utility Commission, Docket No. R-00943231), February 1995. Testified on cost allocation and rate design issues on behalf of the Pennsylvania Office of Consumer Advocate.

NorAm Gas Transmission Company (Federal Energy Regulatory Commission, Docket No. RP93-343-000), March 1995. Testified on rate base, operating expense and income tax issues on behalf of the Arkansas Public Service Commission and the Louisiana Public Service Commission. (Case settled prior to hearings.)

Artesian Water Company, Inc. (Delaware Public Service Commission, Docket No. 94-164), March 1995. Testified on cost allocation, rate design and monthly billing issues on behalf of the Staff of the Public Service Commission. (Case settled prior to cross-examination.)

Pennsylvania Power & Light Company (Pennsylvania Public Utility Commission, Docket No. R-00943271), April 1995. Testified on operating income and rate base issues on behalf of the Pennsylvania Office of Consumer Advocate.

National Fuel Gas Distribution Corporation (Pennsylvania Public Utility Commission, Docket No. R-953299), June 1995. Testified on revenue requirement issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Prior Expert Testimony

of Thomas S. Catlin

Providence Water Supply Board (Rhode Island Public Utilities Commission, Docket No. 2304), July 1995. Testified on water consumption and cost allocation/rate design issues on behalf of the Division of Public Utilities and Carriers.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission, Docket No. RP95-112-000), September 1995. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Transcontinental Gas Pipe Line Corporation (Federal Energy Regulatory Commission, Docket No. RP95-197-000), January 1996. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate. (Case settled prior to cross-examination.)

Frontier Communications of Pennsylvania, et al. (Pennsylvania Public Utility Commission, Docket No. P-00951005), May 1996. Testified regarding financial issues and operational aspects of Companies' proposal to implement a streamlined form of regulation (price cap) on behalf of the Pennsylvania Office of Consumer Advocate.

Bell Atlantic-Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00963550), May 1996. Testified on financial issues, revenue growth, and capital expenditures in conjunction with Bell Atlantic-Pennsylvania's proposal to rebalance rates. Testimony filed on behalf of the Pennsylvania Office of Consumer Advocate.

Petition of AT&T Communications of Pennsylvania for Arbitration of its Interconnection Request to Bell Atlantic-PA (Pennsylvania Public Utility Commission, Docket No. A-310125F0002), September 1996. Sponsored position of Pennsylvania Office of Consumer Advocate on resale discount, 900 number call billing, network interface devices, and unbundled loop rates in arbitration hearings.

Bell Atlantic-Pennsylvania (Pennsylvania Public Utility Commission, Docket No. R-00963578), September 1996. Testified regarding the determination of the appropriate resale discount for Bell Atlantic-Pennsylvania on behalf of the Pennsylvania Office of Consumer Advocate.

Pacific Bell Communications, Inc. (Public Utilities Commission of the State of California, Docket No. 96-03-007), October 1996. Testified on affiliate relationship issues under

Prior Expert Testimony

of Thomas S. Catlin

Section 272 of the Telecommunications Act of 1996 on behalf of the California Cable Television Association.

West Ohio Gas Company (Public Utilities Commission of Ohio, Case No. 96-221-GA-GCR), November 1994. Co-authored report on the audit of the management and performance of gas purchasing on behalf of the Public Utilities Commission of Ohio. (Case settled prior to cross-examination.)

Application of MFS Intelenet of Pennsylvania, Inc. et al. (Phase III) (Pennsylvania Public Utility Commission Docket No. A-310203F0002 et al.), January 1997. Testified on loop cost issues on behalf of the Pennsylvania Office of Consumer Advocate.

Tennessee Gas Pipeline Company (Federal Energy Regulatory Commission Docket Nos. RP91-203-062 and RP92-132-049), March 1997. Testified on ratemaking treatment of New England laterals on behalf of the Tennessee Rate Design Customer Group.

Frontier Communications of Oswayo River, Inc. (Pennsylvania Public Utility Commission Docket Nos. C-00957322 and C-00957324), May 1997. Testified on EAS rate issues on behalf of the Pennsylvania Office of Consumer Advocate.

PECO Energy Company (Pennsylvania Public Utility Commission Docket No. R-00973953), June 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Transcontinental Gas Pipeline Corporation (Federal Energy Regulatory Commission Docket No. RP97-71-000), June 1997. Testified on rate base and cost of service issues on behalf of the Pennsylvania Office of Consumer Advocate.

Pennsylvania Power & Light Company (Pennsylvania Public Utility Commission Docket No. R-00973954), July 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Metropolitan Edison Company (Pennsylvania Public Utility Commission Docket No. R-00974008), September 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

Prior Expert Testimony

of Thomas S. Catlin

Pennsylvania Electric Company (Pennsylvania Public Utility Commission Docket No. R-00974009), September 1997. Testified on issues related to the determination of stranded costs including regulatory assets, decommissioning costs, and income taxes on behalf of the Pennsylvania Office of Consumer Advocate.

COMMONWEALTH OF PENNSYLVANIA

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY	))	DOCKET NO. R-00974104

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

THOMAS S. CATLIN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

NOVEMBER 1997

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

DUQUESNE LIGHT COMPANY

Summary of Regulatory Assets and
Other Transition Expenses
($000)

	Balance Per Company	Balance Per OCA	Net Present Value at 7.83 Percent	Net Present Value at 6.88 Percent
Regulatory Assets				
Regulatory Tax Receivable	$236.48	$236.48	$236.48	$236.48
Unamortized Debt Costs	29.92	45.77	45.77	45.77
Deferred Rate Synch. Costs	33.16	33.16	25.78	26.52
Deferred Employee Costs	17.80	17.80	13.84	14.24
Deferred Nuclear Mainteance	3.25	3.25	3.25	3.25
DOE Decommissioning	7.18	7.18	5.58	5.74
Deferred Coal Costs	13.50	0.00	0.00	0.00
Deferred Caretaker Costs	6.77	0.00	0.00	0.00
BV2 Training Costs	2.42	2.42	2.42	2.42
Low Level Radioactive Waste	2.27	2.27	2.27	2.27
Coal Cost Equalization	0.12	0.12	0.12	0.12
Unamortized Debt Costs-BV2	4.31	Note (1)	Note (1)	Note (1)
BV2 Sale/Leaseback Premium	16.51	Note (1)	Note (1)	Note (1)
NPV of Beaver Valley Lease	227.78	513.36 (2)	475.95 (2)	513.36 (2)
Pre-Accrued Nuclear Outage Costs	22.65	0.00	0.00	0.00
SFAS No. 106 Deferral	4.22	4.22	3.28	3.37
Deferred Fuel Costs	14.81	14.81	11.51	11.84
Other Regulatory Assets	0.53	0.53	0.53	0.53
Gain on Sale Leaseback Tax Effect	55.13	55.13	55.13	55.13
Deferred Rate Synch. Tax Effect	0.27	0.27	0.21	0.22
Beaver Valley 2 Tax Effect	0.17	0.17	0.17	0.17
SFAS No. 109 Plant	62.94	0.00	0.00	0.00
Total Regulatory Assets	$762.19	$936.94 (2)	$882.29 (2)	$921.43 (2)
Other Transition Expenses				
Pilot Program Implementation	2.50	2.50	2.50	2.50
Customer Education	2.00	2.00	2.00	2.00
Restructuring Filing	1.00	1.00	1.00	1.00
Restructuring Implementation	8.30	8.30	8.30	8.30
Deferred Pilot Program Costs	4.40	4.40	4.40	4.40
Total Transition Expenses	$18.20	$18.20	$18.20	$18.20

Notes:

(1) Included as part of net present value (NPV) of Beaver Valley 2 lease payments.

(2) The present value of the Beaver Valley 2 lease payments has been included here as a regulatory asset consistent with Duquesne's presentation. However, for puposes of his analysis, Mr Kahal has recognized the Beaver Valley 2 sale/leaseback as part of Duquesne's company-owned generation and has transferred this balance from regulatory assets to net plant.

DUQUESNE LIGHT COMPANY

Summary of Decommissioning Funding Requirements
As of December 31, 1998

Based on Funding over 7 Year CTC Collection Period

Nuclear Unit	Annual Contribution (1)	Funding Period
Beaver Valley 1	$3,132	1999-2005
Beaver Valley 2	1,434	1999-2005
Perry Unit 1	3,383	1999-2005
Total	$7,949	

Note:

(1) Refer to pages 2 through 4 of this schedule for derivation.

DUQUESNE LIGHT COMPANY

Beaver Valley 1 Decommissioning Funding Analysis
($000)

Line No	Year	Revenue Rqmt. [1]	Decommioning Fund Details: Earning Rate [2]	Transfer To Fund [3]	Earnings [4]	Net Additions [5]	Decomm. Expend [6]	Balance [7]
1	Beginning Balance							24,029
2	1997	5,509	0.0750	5,509	2,066	7,575	0	31,604
3	1998	5,509	0.0750	5,509	2,650	8,159	0	39,763
4	1999	3,132	0.0750	3,132	3,188	6,320	0	46,083
5	2000	3,132	0.0750	3,132	3,675	6,807	0	52,891
6	2001	3,132	0.0750	3,132	4,201	7,333	0	60,223
7	2002	3,132	0.0750	3,132	4,766	7,898	0	68,121
8	2003	3,132	0.0750	3,132	5,375	8,507	0	76,628
9	2004	3,132	0.0750	3,132	6,032	9,164	0	85,792
10	2005	3,132	0.0750	3,132	6,738	9,870	0	95,662
11	2006	0	0.0750	0	7,379	7,379	0	103,041
12	2007	0	0.0750	0	7,948	7,948	0	110,990
13	2008	0	0.0750	0	8,561	8,561	0	119,551
14	2009	0	0.0750	0	9,222	9,222	0	128,773
15	2010	0	0.0750	0	9,933	9,933	0	138,706
16	2011	0	0.0750	0	10,699	10,699	0	149,405
17	2012	0	0.0750	0	11,524	11,524	0	160,929
18	2013	0	0.0750	0	12,413	12,413	0	173,343
19	2014	0	0.0750	0	13,371	13,371	0	186,714
20	2015	0	0.0750	0	14,402	14,402	0	201,116
21	2016	0	0.0750	0	14,555	14,555	(24,841)	190,830
22	2017	0	0.0750	0	14,042	14,042	(17,564)	187,309
23	2018	0	0.0750	0	14,304	14,304	(3,730)	197,883
24	2019	0	0.0750	0	15,114	15,114	(3,879)	209,118
25	2020	0	0.0750	0	15,974	15,974	(4,045)	221,047
26	2021	0	0.0750	0	16,889	16,889	(4,196)	233,740
27	2022	0	0.0750	0	17,861	17,861	(4,364)	247,238
28	2023	0	0.0750	0	18,896	18,896	(4,538)	261,596
29	2024	0	0.0750	0	19,996	19,996	(4,733)	276,859
30	2025	0	0.0750	0	21,166	21,166	(4,908)	293,117
31	2026	0	0.0750	0	22,413	22,413	(5,105)	310,425
32	2027	0	0.0750	0	23,773	23,773	(4,465)	329,734
33	2028	0	0.0750	0	25,277	25,277	(4,070)	350,941
34	2029	0	0.0750	0	25,984	25,984	(28,149)	348,776
35	2030	0	0.0750	0	24,324	24,324	(66,864)	306,236
36	2031	0	0.0750	0	19,488	19,488	(107,193)	218,531
37	2032	0	0.0750	0	12,563	12,563	(111,335)	119,759
38	2033	0	0.0750	0	5,651	5,651	(93,002)	32,408
39	2034	0	0.0750	0	1,487	1,487	(26,251)	7,644
40	2035	0	0.0750	0	284	284	(7,928)	0
		$32,942		$32,942	$474,189	$507,130	($531,159)	

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded quarterly at Current Year Earning Rate.
5) Transfer + Earnings.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

DUQUESNE LIGHT COMPANY

Beaver Valley 2 Decommissioning Funding Analysis
($000)

Line No	Year	Revenue Rqmt. [1]	Decommioning Fund Details: Earning Rate [2]	Transfer To Fund [3]	Earnings [4]	Net Additions [5]	Decomm. Expend [6]	Balance [7]
1	Beginning Balance							5,099
2	1997	1,014	0.0750	1,014	432	1,446	0	6,545
3	1998	1,014	0.0750	1,014	544	1,558	0	8,103
4	1999	1,434	0.0750	1,434	680	2,114	0	10,218
5	2000	1,434	0.0750	1,434	843	2,278	0	12,495
6	2001	1,434	0.0750	1,434	1,019	2,453	0	14,949
7	2002	1,434	0.0750	1,434	1,208	2,642	0	17,591
8	2003	1,434	0.0750	1,434	1,412	2,846	0	20,438
9	2004	1,434	0.0750	1,434	1,632	3,066	0	23,503
10	2005	1,434	0.0750	1,434	1,868	3,302	0	26,806
11	2006	0	0.0750	0	2,068	2,068	0	28,874
12	2007	0	0.0750	0	2,227	2,227	0	31,101
13	2008	0	0.0750	0	2,399	2,399	0	33,500
14	2009	0	0.0750	0	2,584	2,584	0	36,084
15	2010	0	0.0750	0	2,783	2,783	0	38,867
16	2011	0	0.0750	0	2,998	2,998	0	41,865
17	2012	0	0.0750	0	3,229	3,229	0	45,094
18	2013	0	0.0750	0	3,478	3,478	0	48,573
19	2014	0	0.0750	0	3,747	3,747	0	52,319
20	2015	0	0.0750	0	4,036	4,036	0	56,355
21	2016	0	0.0750	0	4,347	4,347	0	60,702
22	2017	0	0.0750	0	4,682	4,682	0	65,385
23	2018	0	0.0750	0	5,043	5,043	0	70,428
24	2019	0	0.0750	0	5,433	5,433	0	75,861
25	2020	0	0.0750	0	5,852	5,852	0	81,712
26	2021	0	0.0750	0	6,303	6,303	0	88,015
27	2022	0	0.0750	0	6,789	6,789	0	94,804
28	2023	0	0.0750	0	7,313	7,313	0	102,117
29	2024	0	0.0750	0	7,877	7,877	0	109,994
30	2025	0	0.0750	0	8,484	8,484	0	118,478
31	2026	0	0.0750	0	9,139	9,139	0	127,617
32	2027	0	0.0750	0	9,448	9,448	(10,263)	126,802
33	2028	0	0.0750	0	8,990	8,990	(20,506)	115,286
34	2029	0	0.0750	0	7,939	7,939	(24,718)	98,508
35	2030	0	0.0750	0	6,670	6,670	(24,072)	81,106
36	2031	0	0.0750	0	5,361	5,361	(23,207)	63,261
37	2032	0	0.0750	0	3,903	3,903	(25,330)	41,834
38	2033	0	0.0750	0	2,634	2,634	(15,370)	29,097
39	2034	0	0.0750	0	1,727	1,727	(13,417)	17,407
40	2035	0	0.0750	0	986	986	(9,261)	9,132
41	2036	0	0.0750	0	669	669	(918)	8,883
42	2037	0	0.0750	0	649	649	(950)	8,582
43	2038	0	0.0750	0	624	624	(988)	8,218
44	2039	0	0.0750	0	594	594	(1,028)	7,785
45	2040	0	0.0750	0	559	559	(1,074)	7,270
46	2041	0	0.0750	0	518	518	(1,111)	6,677
47	2042	0	0.0750	0	470	470	(1,156)	5,991
48	2043	0	0.0750	0	222	222	(6,214)	0
		$12,067		$12,067	$162,415	$174,482	($179,581)	

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded monthly at Current Year Earning Rate.
5) Transfer + Earnings.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

DUQUESNE LIGHT COMPANY

Perry Unit 1 Decommissioning Funding Analysis
($000)

Line No	Year	Revenue Rqmt. [1]	Decommioning Fund Details: Earning Rate [2]	Transfer To Fund [3]	Earnings [4]	Net Additions [5]	Decomm. Expend [6]	Balance [7]
1	*Beginning Balance*							4,611
2	1997	2,239	0.0750	2,239	442	2,681	0	7,292
3	1998	2,239	0.0750	2,239	649	2,888	0	10,180
4	1999	3,383	0.0750	3,383	916	4,299	0	14,479
5	2000	3,383	0.0750	3,383	1,247	4,630	0	19,109
6	2001	3,383	0.0750	3,383	1,604	4,988	0	24,097
7	2002	3,383	0.0750	3,383	1,989	5,372	0	29,469
8	2003	3,383	0.0750	3,383	2,404	5,787	0	35,255
9	2004	3,383	0.0750	3,383	2,850	6,233	0	41,488
10	2005	3,383	0.0750	3,383	3,331	6,714	0	48,202
11	2006	0	0.0750	0	3,718	3,718	0	51,920
12	2007	0	0.0750	0	4,005	4,005	0	55,925
13	2008	0	0.0750	0	4,314	4,314	0	60,239
14	2009	0	0.0750	0	4,647	4,647	0	64,886
15	2010	0	0.0750	0	5,005	5,005	0	69,891
16	2011	0	0.0750	0	5,391	5,391	0	75,282
17	2012	0	0.0750	0	5,807	5,807	0	81,089
18	2013	0	0.0750	0	6,255	6,255	0	87,343
19	2014	0	0.0750	0	6,737	6,737	0	94,081
20	2015	0	0.0750	0	7,257	7,257	0	101,338
21	2016	0	0.0750	0	7,817	7,817	0	109,155
22	2017	0	0.0750	0	8,420	8,420	0	117,574
23	2018	0	0.0750	0	9,069	9,069	0	126,644
24	*2019*	*0*	*0.0750*	*0*	*9,769*	*9,769*	*0*	136,412
25	2020	0	0.0750	0	10,522	10,522	0	146,935
26	2021	0	0.0750	0	11,334	11,334	0	158,268
27	2022	0	0.0750	0	12,208	12,208	0	170,477
28	2023	0	0.0750	0	13,150	13,150	0	183,627
29	2024	0	0.0750	0	14,164	14,164	0	197,791
30	2025	0	0.0750	0	15,257	15,257	0	213,047
31	2026	0	0.0750	0	16,434	16,434	0	229,481
32	2027	0	0.0750	0	16,989	16,989	(18,457)	228,013
33	2028	0	0.0750	0	16,166	16,166	(36,874)	207,305
34	2029	0	0.0750	0	14,276	14,276	(44,449)	177,132
35	2030	0	0.0750	0	11,994	11,994	(43,287)	145,839
36	2031	0	0.0750	0	9,640	9,640	(41,736)	113,743
37	2032	0	0.0750	0	7,017	7,017	(45,547)	75,213
38	2033	0	0.0750	0	4,736	4,736	(27,639)	52,309
39	2034	0	0.0750	0	3,104	3,104	(24,127)	31,286
40	2035	0	0.0750	0	1,771	1,771	(16,654)	16,403
41	2036	0	0.0750	0	1,202	1,202	(1,645)	15,960
42	2037	0	0.0750	0	1,165	1,165	(1,706)	15,419
43	2038	0	0.0750	0	1,121	1,121	(1,774)	14,766
44	2039	0	0.0750	0	1,068	1,068	(1,845)	13,989
45	2040	0	0.0750	0	1,005	1,005	(1,924)	13,070
46	2041	0	0.0750	0	931	931	(1,996)	12,005
47	2042	0	0.0750	0	846	846	(2,075)	10,776
48	2043	0	0.0750	0	400	400	(11,176)	0
		$28,159		$28,159	$290,142	$318,301	($322,912)	

Notes:

1) The 1999 Revenue Requirement was chosen so that the Decommissioning Fund Balance is zero in the last year of decommissioning.
2) Projected after-tax earning rate.
3) Same as revenue requirement.
4) Prior Year Balance + ½ Current Year Transfer with interest compounded quarterly at Current Year Earning Rate.
5) Transfer + Earnings.
6) Decommissioning expenditures.
7) Prior Year Balance + Net Additions - Decommissioning Expenditure.

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