

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission)	
)	
v.)	Docket No. R-00049255
)	
PPL Electric Utilities Corporation)	

EXHIBITS
OF
STEPHEN J. BARON

ON BEHALF OF
PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

June 2004

DOCUMENT

Expert Testimony Appearances
of
Stephen J. Baron
As June 2004

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Date	Case	Jurisdct.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	PA PUBLIC UTILITY COMMISSION SECRETARY'S BUREAU
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenor	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

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6/85	84-768- E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arka, Inc.	Regulatory policy, gas cost-of- service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER- 8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726- EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081- E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

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3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

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10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171- EL-AIR 88-170- EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171- EL-AIR 88-170- EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

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8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenor	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airoo Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

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8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand- side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-JNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410- EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

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8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO ₂ allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

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4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035- E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

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8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank- ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

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7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross- 40-000 Answering Testimony)	EC-98-	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

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5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. gas services.	Performance based regulation, settlement proposal issues, cross-subsidies between electric.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658- EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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08/00	98-0452 E-GI 98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473- 00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66- 000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPSCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and The Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000, FERC ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002		Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

J. KENNEDY AND ASSOCIATES, INC.

**Expert Testimony Appearances
of
Stephen J. Baron
As June 2004**

Date	Case	Jurisdic.	Party	Utility	Subject
04/04	2003-00433 2003-00434	PA	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates

J. KENNEDY AND ASSOCIATES, INC.

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PPL Electric Utilities Corporation
Development of Transmission Service Charge
PPL Forecasted 2004 Transmission Charges

	(1) OATT Sched	(2) Total Charges	(3) Demand Charges	(4) Energy Charges
1 Network Transmission Charges		125,281,324	125,281,324	
2 Ancillary Services Charges				
3 PJM Scheduling & Dispatch	9	13,579,891		13,579,891
4 Trans Owner Sched & Dispatch	1A	2,067,087		2,067,087
5 Reactive Supply & Voltage Control	2	12,306,363	12,306,363	
6 Black Start	6A	146,340	146,340	
7 PJM West Transition Charge	11	1,274,369		1,274,369
8 Area Regulation	3	16,720,420		16,720,420
9 Day-ahead Operating Reserve	5 & 6	6,881,231		6,881,231
10 Real-time Operating Reserve	5 & 6	2,231,714		2,231,714
11 Spinning Reserve (Condensing)	5 & 6	6,799,980		6,799,980
12 MAAC		334,480		334,480
13 PJM Membership Dues		5,000		5,000
14 Total Ancillary Services		62,946,875	12,452,703	49,894,172
15 Total Transmission Charges		187,628,199	137,734,027	49,894,172
16 Gross Receipts Tax (GRT)		11,764,149	8,635,821	3,128,327
17 Total Trans Charges w/GRT		199,392,348	146,369,848	53,022,500
18 Less: Collections from ISA/PRS		(417,409)	(306,411)	(110,998)
19 Net Charges for POLR Rates		198,974,939	146,063,437	52,911,502
20 POLR mW / kWh @ Trans			6,513.1	36,901,334,567
21 POLR Demand Rate (\$/mW-yr)	TSC _D		22,426	
22 POLR Energy Rate (\$/kWh)	TSC _E			0.00143

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line 16 = line 15 x 1/(1-.059)

line 18 = PPL estimate of transmission revenues from ISA/PRS, spread pro rata to demand/energy

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Exhibit _____ (SJB-3)
Page 1 of 3

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D. A. Krall

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PPL Electric Utilities Corporation
Response to Interrogatories of the
PP&L Industrial Customer Alliance, Set I,
Dated April 29, 2004

Docket No. R-00049255

- Q.11. Please explain how PPL determines the transmission obligation for a PPL retail customer that purchases generation supply from an Electric Generation Supplier ("EGS"). If this methodology differs for some or all rate schedules, please explain each methodology, including any adjustments made to reflect active load management or other demand side response actions. If the methodology does not differ by rate schedule, please explain why the same methodology is used for both firm and interruptible rate schedules.
- A.11. Attachment 1 titled "*PPL Peak Load Allocation Procedure Overview for Network Integrated Transmission Service (NITS)*" provides a summary explanation of the methodology.

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Exhibit _____ (SJB-3)
Page 2 of 3

AUG 17 2004 Attachment 1

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***PPL Peak Load Allocation Procedure Overview
For Network Integrated Transmission Service (NITS)***

Concept

The PPL Peak Load Allocation Procedure for NITS to PPL Zone customers is based on determining what each customer typically contributes to a typical peak load day in the PPL Zone. This peak is allocated out to the customers that existed at the time of the five (5) peak load days in the PPL Zone based on their average contribution to the five peak load days.

Peak Load Allocation Procedure

Peak Load to be Allocated

The peak load that is allocated is the PPL Zone hourly peak for the 12-month period ending October 31 of the previous year.

The PPL Zone peak load is reduced by removing the contributions to the peak that are associated with UGI and the FERC municipal accounts in the PPL Zone based on their actual load at the time of the peak.

Allocation to Rate Schedules

The adjusted PPL Zone peak load is then allocated to each of PPL rate schedule (or profile group within a rate schedule) based on each rate schedule's average contribution to a typical peak load day. The average contribution is based on its average percent share of the peak on the five highest peak load days in the PPL Zone. That average percent contribution is then applied to the single adjusted PPL Zone peak load to determine the peak load responsibility (PLR) assigned to that rate schedule.

Allocation to Customers

The Rate Schedule Peak load responsibility is then allocated to each customer in that rate schedule based on the data available for that rate schedule.

The PLR for the *Interval Metered* rate schedules (LPEP, LP6 LP5, Hourly metered LP4, IS1, ISP, IST, ISM) is allocated to each customer that

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existed in that rate schedule at the time of the Zone peak based on the customer's average contribution to a typical peak load day. The average contribution is based on its average percent share of the peak on the same five highest peak load days used for the allocation to the rate schedule. That average percent contribution is then applied to PLR allocated to that rate schedule to determine the PLR assigned to that customer. There are no adjustments made for Active Load Management (ALM) customers who may have taken an interruption at the time of any of the five peaks.

The PLR for the **Registered Demand** metered rate schedules (remaining LP4, GS3L, GS3M, GS3L) is allocated to each customer that existed in that rate schedule at the time of the Zone peak based on the customer's average contribution to a typical peak load day. The average contribution is based on its average percent share of the sum of the peak demands in the month prior to the five highest peak load days. That average percent contribution is then applied to PLR allocated to that rate schedule to determine the PLR assigned to that customer.

This allocation is somewhat more diversified than that of the Interval Metered customers, but is based on the best available data for these customers.

The PLR for the **Monthly Metered** (kWh only meter) rate schedules (GRS, EXR, RTS, GS1L, GS1M, GS1U, GH, STL) is allocated to each customer that existed in that rate schedule at the time of the Zone peak based on the customer's average annual kWh as a percentage of the rate schedule's annual kWh. That percent contribution to the rate schedule's annual kWh is then applied to PLR allocated to that rate schedule to determine the PLR assigned to that customer.

PPL Electric Utilities Corporation
 Rates resulting from application of TSC factors to individual rate schedules

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Rate Schedule	POLR Load Resp	POLR kWh	Demand Charges	Energy Charges	Demand Rate \$/kW-mo	Energy Rate \$/kWh	Total Charges	PPL Proposal	Difference
1 RS & BL	3,325.9	13,280,052,825	74,586,167	20,200,680		0.00714	94,786,847	74,899,497	19,887,350
2 GS1	347.1	2,007,388,350	7,783,856	3,053,498		0.00540	10,837,353	11,321,670	(484,317)
3 GS3	1,203.1	8,206,402,100	26,981,158	12,483,000		0.00481	39,464,158	46,284,108	(6,819,950)
4 LP4	730.6	5,148,679,435	16,384,973	7,607,193	1.869	0.00148	23,992,166	29,038,552	(5,046,386)
5 LP5	440.0	3,154,280,325	9,867,443	4,522,810	1.869	0.00143	14,390,252	17,790,141	(3,399,889)
6 LP6	54.6	511,847,000	1,224,328	733,919	1.869	0.00143	1,958,247	2,886,817	(928,570)
7 LPEP	10.8	72,000,000	241,303	103,238	1.869	0.00143	344,541	406,080	(61,539)
8 GH	117.4	393,337,962	2,633,351	598,318		0.00822	3,231,669	2,218,426	1,013,243
9 STL	22.1	111,555,602	495,762	169,691		0.00597	665,453	629,174	36,279
10 IS1	0.5	2,120,000	10,701	3,225	1.869	0.00152	13,926	11,957	1,969
11 ISP	54.7	410,790,428	1,227,033	606,944	1.869	0.00148	1,833,977	2,316,858	(482,881)
12 IST	206.3	1,972,981,237	4,627,362	2,828,987	1.869	0.00143	7,456,349	11,127,614	(3,671,265)
13 Sub-total	6,513.1	35,271,435,264	146,063,437	52,911,502			198,974,939	198,930,894	44,045
14 ISA/PRS	42.0	274,418,494	306,411	110,998			417,409	417,409	-
15 Total	6,555.1	35,545,853,758	146,369,848	53,022,500			199,392,348	199,348,303	44,045

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TRANSMISSION SERVICE CHARGE
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A Transmission Service Charge, consisting of a TSC_D and a TSC_E, shall be applied to each rate schedule's 5 coincident peak demand (as defined below) and each rate schedule's kilowatt-hours supplied at transmission voltage to customers of each such rate schedule who receive Basic Utility Supply Service ("BUSS"), as defined in Rule 1B(1), from the Company under this Tariff. The TSC_D and TSC_E, shall be determined to the nearest one cent per kW (TSC_D) and one-thousandth of 1 mill per kilowatt-hour (TSC_E), in accordance with the formula set forth below:

$$TSC_D = [TC_D / PKW] \times [1 / (1 - T)]$$

$$TSC_E = [TC_E / S_{tm}] \times [1 / (1 - T)]$$

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Where:

TSC_D = Demand portion of the Transmission Service Charge, stated in dollars per kW year.

TSC_E = Energy portion of the Transmission Service Charge, stated in mills per kilowatt-hour, at transmission voltage.

TC_D = The total estimated charges for the PPL Transmission Obligation, Reactive Power and Black Start, to be incurred by the Company to provide transmission service under the PJM Open Access Transmission Tariff (OATT), approved or accepted by the Federal Energy Regulatory Commission, for customers who receive BUSS from the Company, unless such customers obtain transmission service from another provider.

TC_E = All remaining estimated charges for transmission service (not included in TC_D (above) under the PJM Open Access Transmission Tariff (OATT), approved or accepted by the Federal Energy Regulatory Commission, for customers who receive BUSS from the Company, unless such customers obtain transmission service from another provider.

PPLICA PROPOSED

TRANSMISSION SERVICE CHARGE (continued)

Transmission Charge -- all applicable charges incurred by the Company to acquire transmission service (including ancillary service charges) on behalf of BUSS customers under the PJM OATT.

The Computation year c shall be January 1 through December 31 over which the TSC_D and TSC_E , as computed, will apply.

- PKW = The sum of rate schedule 5 coincident peak demands (to which the TSC_D applies), as used by PJM to allocate PPL zonal transmission charges,
- S_{tm} = The sum of rate schedule kWh sales (to which the TSC_E applies), adjusted for losses, at the transmission voltage level.
- T = The total Pennsylvania gross receipts tax rate in effect during the billing month, expressed in decimal form.

The TSC_D and TSC_E shall be filed with the Pennsylvania Public Utility Commission by December 1 of each year. The TSC_D and TSC_E rates shall become effective for transmission service acquired on behalf of BUSS customers and rendered to those customers on or after January 1, unless otherwise ordered by the Commission, and shall remain in effect for a period on one year, unless revised on an interim basis subject to the approval of the Commission, via rate schedule conversion factors that shall be filed by the Company that convert the TSC_D and TSC_E rates into equivalent rates for each rate schedule that shall be applied to each customer's monthly bill.

For rate schedules for which there is interval metering (including Rate Schedule LP-4 hourly), customers will be billed directly at the TSC_D rate, divided by 12, applied to such customer's 5 coincident peak demand contribution to "PKW" above. For Rate Schedule LP-4 customers without interval metering, billing will be based on such customer's 5 coincident peak demand, as estimated by PPL and provided to PJM. For all other rate schedules, the conversion process for the TSC_D charge shall equal the TSC_D times the rate schedule's 5 coincident peak demand (as used in "PKW" above), divided by forecasted rate schedule kWh sales for the period.

The conversion process for TSC_E shall equal the TSC_E rate times the rate schedule's kWh sales at the transmission voltage level (as used in S_{tm} above), divided by rate schedule kWh sales for the period.

All conversion process shall be updated annually at the time of the update of the TSC_D and TSC_E rates.

Upon a FERC approved change to the applicable rates contained in the PJM OATT, the Company may file with the Commission for an interim revision of the TSC_D and TSC_E to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

Minimum bills shall not be reduced by reason of the TSC_D and TSC_E, nor shall charges hereunder be a part of the monthly rate schedule minimum. The TSC_D and TSC_E shall not be subject to any credits or discounts and shall not be affected by the State Tax Adjustment Surcharge (STAS).

Application of the TSC shall be subject to review and audit by the Commission at intervals it shall determine. The Commission shall review the level of charges produced by the TSC_D and TSC_E and the costs included therein.

PPL Electric Utilities Corporation
 Summary of Subsidies under Present and Proposed Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
<u>Rate Class</u>	<u>Rate Base</u>	<u>Present Return</u>	<u>Present Rate of Return</u>	<u>Present Subsidy</u>	<u>PPL Proposed Return</u>	<u>Proposed Rate of Return</u>	<u>PPL Proposed Subsidy</u>	<u>% Change in Subsidy</u>
1 RS	1,216,771	19,428	1.60%	(51,291)	64,422	5.29%	(77,823)	51.7%
2 RTS	41,367	(1,636)	-3.95%	(5,932)	(1,329)	-3.21%	(9,064)	52.8%
3 GS-1	179,297	16,646	9.28%	17,580	28,986	16.17%	24,084	37.0%
4 GS-3	250,040	26,247	10.50%	30,048	50,186	20.07%	51,393	71.0%
5 LP-4	61,618	6,554	10.64%	7,561	12,385	20.10%	12,697	67.9%
6 ISP	3,796	549	14.46%	731	763	20.10%	782	7.0%
7 LP-5	2,036	480	23.58%	730	495	24.31%	576	-21.1%
8 IST	716	624	87.15%	1,087	314	43.85%	458	-57.9%
9 LP-6	144	116	80.56%	201	63	43.75%	92	-54.4%
10 LPEP	825	92	11.15%	109	136	16.48%	116	6.1%
11 ISA	284	306	107.75%	538	305	107.39%	511	-5.1%
12 GH	19,682	1,921	9.76%	2,101	3,605	18.32%	3,415	62.6%
13 SL/AL	66,001	677	1.03%	(3,469)	1,820	2.76%	(7,275)	109.7%
14 L5-S	177	10	5.65%	6	37	20.90%	39	594.8%
15 Total	1,842,754	72,014	3.91%	(0)	162,188	8.80%	0	

Gross Revenue Conversion Factor (calculated from Exh Future 1, Sch D-13, p.4 of 4 - 164,438/99162)

1.82381

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PPL Electric Utilities Corporation
Large Power Rate Schedule Cost Analysis
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	<u>PPL **</u>	<u>Equal ROR **</u>	<u>Difference (subsidy payment)</u>
LP-4			
1 Present Distribution Revenues *	21,644,016	21,644,016	
2 Distribution Rate Increase	10,750,484	(1,946,413)	
3 Proposed Distribution Revenues	32,394,500	19,697,603	
4 Distribution Rate per kW-mo	\$ 2.632	\$ 1.600	\$ (1.032)
LP-5			
5 Present Distribution Revenues *	1,606,754	1,606,754	
6 Distribution Rate Increase	18,733	(557,232)	
7 Proposed Distribution Revenues	1,625,487	1,049,522	
8 Distribution Rate per kW-mo	\$ 0.320	\$ 0.207	\$ (0.113)
LP-6			
9 Present Distribution Revenues *	283,081	283,081	
10 Distribution Rate Increase	(97,808)	(189,593)	
11 Proposed Distribution Revenues	185,273	93,488	
12 Distribution Rate per kW-mo	\$ 0.211	\$ 0.106	\$ (0.105)
IS-P			
13 Present Distribution Revenues *	1,741,446	1,741,446	
14 Distribution Rate Increase	383,427	(398,802)	
15 Proposed Distribution Revenues	2,124,873	1,342,644	
16 Distribution Rate per kW-mo	\$ 5.132	\$ 3.243	\$ (1.889)
IS-T			
17 Present Distribution Revenues *	1,454,841	1,454,841	
18 Distribution Rate Increase	(564,896)	(1,022,639)	
19 Proposed Distribution Revenues	889,945	432,202	
20 Distribution Rate per kW-mo	\$ 0.932	\$ 0.453	\$ (0.479)

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* Does not include PRS revenues.

** Includes SEF Charges

PPL Electric Utilities Corporation
 Summary of Increases under PPL Proposed Rates

	Rate Class	(1)	(2)	(3)	(4)	(5) - (8)				(9)	(10)
		Present Distribution Revenues	Proposed Distribution Revenue	Increase	Percent Increase	Other Present Rate Revenues				Total Present Revenues	% Increase on Total Revenues
						Trans	CTC	ITC	E&C		
1	RS, RTD	293,920	374,883	80,963	27.5%	49,096	28,548	135,521	573,686	1,080,771	7.5%
2	RTS	3,513	4,081	568	16.2%	481	546	3,164	15,847	23,552	2.4%
3	GS-1	61,460	83,476	22,016	35.8%	11,837	6,943	25,562	110,883	216,686	10.2%
4	GS-3	84,183	127,283	43,100	51.2%	38,399	26,171	96,745	406,404	651,901	6.6%
5	LP-4 *	21,644	32,395	10,750	49.7%	19,785	15,363	51,551	220,322	328,667	3.3%
6	ISP *	1,741	2,125	383	22.0%	1,497	61	3,313	13,611	20,224	1.9%
7	LP-5 *	1,607	1,625	19	1.2%	9,699	8,483	28,386	118,423	166,598	0.0%
8	IST *	1,455	890	(565)	-38.8%	7,066	(1,168)	15,304	58,283	80,940	-0.7%
9	LP-6	283	185	(98)	-34.6%	1,574	143	6,233	20,288	28,520	-0.3%
10	LPEP	313	404	91	29.0%	39	343	1,773	2,223	4,691	1.9%
11	ISA *	649	649	0	0.0%	357	(1,144)	2,716	3,019	5,597	0.0%
12	GH	6,222	9,193	2,971	47.7%	1,836	707	8,465	16,517	33,747	8.8%
13	SL/AL	17,705	19,805	2,100	11.9%	362	77	1,085	4,585	23,814	8.8%
14	L5-S	36	83	47	128.1%	22	(68)	276	872	1,137	4.1%
15	Total w/o PRS	494,732	657,077	162,345	32.8%	142,050	85,006	380,094	1,564,962	2,666,846	6.1%
16	PRS	686	686	-	0.0%	60	8	76	5,603	6,424	0.0%
17	Total w/o PRS	495,418	657,763	162,345	32.8%	142,110	85,014	380,170	1,570,565	2,673,270	6.1%

* Excludes revenues from PRS which are included in COSS revenues

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PPL Electric Utilities Corporation
 Summary of Increases required to equalize ROR at Proposed Rates

	(1) Rate Class	(2) Present Distribution Revenues	(3) Proposed Distribution Revenue	(4) Increase	(5) Percent Increase	(6) Other Present Rate Revenues				(9) Total Present Revenues	(10) % Increase on Total Revenues
						(7) Trans	(8) CTC	(9) ITC	(10) E&C		
1	RS, RTD	293,920	452,706	158,786	54.0%	49,096	28,548	135,521	573,686	1,080,771	14.7%
2	RTS	3,513	13,145	9,632	274.2%	481	546	3,164	15,847	23,552	40.9%
3	GS-1	61,460	59,392	(2,068)	-3.4%	11,837	6,943	25,562	110,883	216,686	-1.0%
4	GS-3	84,183	75,890	(8,293)	-9.9%	38,399	26,171	96,745	406,404	651,901	-1.3%
5	LP-4 *	21,644	19,698	(1,946)	-9.0%	19,785	15,363	51,551	220,322	328,667	-0.6%
6	ISP *	1,741	1,343	(399)	-22.9%	1,497	61	3,313	13,611	20,224	-2.0%
7	LP-5 *	1,607	1,050	(557)	-34.7%	9,699	8,483	28,386	118,423	166,598	-0.3%
8	IST *	1,455	432	(1,023)	-70.3%	7,066	(1,168)	15,304	58,283	80,940	-1.3%
9	LP-6	283	93	(190)	-67.0%	1,574	143	6,233	20,288	28,520	-0.7%
10	LPEP	313	288	(25)	-7.9%	39	343	1,773	2,223	4,691	-0.5%
11	ISA *	649	139	(511)	-78.6%	357	(1,144)	2,716	3,019	5,597	-9.1%
12	GH	6,222	5,777	(445)	-7.1%	1,836	707	8,465	16,517	33,747	-1.3%
13	SL/AL	17,705	27,080	9,375	53.0%	362	77	1,085	4,585	23,814	39.4%
14	L5-S	36	44	8	20.9%	22	(68)	276	872	1,137	0.7%
15	Total w/o PRS	494,732	657,077	162,345	32.8%	142,050	85,006	380,094	1,564,962	2,666,843	6.1%
16	PRS	686	686	-	0.0%	60	8	76	5,603	6,434	0.0%
17	Total w/o PRS	495,418	657,763	162,345	32.8%	142,110	85,014	380,170	1,570,565	2,673,277	6.1%

* Excludes revenues from PRS which are included in COSS revenues

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PPL Electric Utilities Corporation
 Summary of PPLICA Proposed Increases
 Present Rate Subsidies reduced by at least 50%

	Rate Class	(1)	(2)	(3)	(4)	(5) - (8)				(9)	(10)
		Present Distribution Revenues	Proposed Distribution Revenue	Increase	Percent Increase	Other Present Rate Revenues				Total Present Revenues	% Increase on Total Revenues
						Trans	CTC	ITC	E&C		
1	RS, RTD	293,920	427,061	133,141	45.3%	49,096	28,548	135,521	573,686	1,080,771	12.3%
2	RTS	3,513	10,179	6,666	189.8%	481	546	3,164	15,847	23,552	28.3%
3	GS-1	61,460	68,182	6,722	10.9%	11,837	6,943	25,562	110,883	216,686	3.1%
4	GS-3	84,183	90,914	6,731	8.0%	38,399	26,171	96,745	406,404	651,901	1.0%
5	LP-4 *	21,644	23,562	1,918	8.9%	19,785	15,363	51,551	220,322	328,667	0.6%
6	ISP *	1,741	1,714	(27)	-1.6%	1,497	61	3,313	13,611	20,224	-0.1%
7	LP-5 *	1,607	1,420	(187)	-11.6%	9,699	8,483	28,386	118,423	166,598	-0.1%
8	IST *	1,455	890	(565)	-38.8%	7,066	(1,168)	15,304	58,283	80,940	-0.7%
9	LP-6	283	185	(98)	-34.6%	1,574	143	6,233	20,288	28,520	-0.3%
10	LPEP	313	343	30	9.5%	39	343	1,773	2,223	4,691	0.6%
11	ISA *	649	408	(242)	-37.2%	357	(1,144)	2,716	3,019	5,597	-4.3%
12	GH	6,222	6,828	606	9.7%	1,836	707	8,465	16,517	33,747	1.8%
13	SL/AL	17,705	25,345	7,640	43.2%	362	77	1,085	4,585	23,814	32.1%
14	L5-S	36	47	10	28.6%	22	(68)	276	872	1,137	0.9%
15	Total w/o PRS	494,732	657,077	162,345	32.8%	142,050	85,006	380,094	1,564,962	2,666,843	6.1%
16	PRS	686	686	-	0.0%	60	8	76	5,603	6,434	0.0%
17	Total w/o PRS	495,418	657,763	162,345	32.8%	142,110	85,014	380,170	1,570,565	2,673,277	6.1%

* Excludes revenues from PRS which are included in COSS revenues

	50% Subsidy Reduction
LP-4	23,478
ISP	1,708
LP-5	1,415
IST	976
LP-6	194

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PPL Electric Utilities Corporation
 Summary of Impacts of Proposed TSC and Distribution Increases
 Reflects Distribution Charges for all customers; Transmission imputed for all customers

	(1) Total Present Revenues	(2) PPL Distribution Increase	(3) PPL Transmission Increase	(4) PPL Total Increase	(5) PPL % Increase	(6) PPLICA Distribution Increase	(7) PPLICA Transmission Increase	(8) PPLICA Total Increase	(9) PPLICA % Increase
1 RS	1,081,597,743	80,930,691	23,551,651	104,482,342	9.7%	133,086,281	42,861,753	175,948,034	16.3%
2 RTS	23,568,392	568,224	1,774,474	2,342,698	9.9%	6,666,247	2,373,487	9,039,734	38.4%
3 RTD	420,490	32,127	9,670	41,797	9.9%	54,444	17,599	72,043	17.1%
4 GS-1	217,363,810	21,958,604	(483,059)	21,475,545	9.9%	6,697,273	(972,269)	5,725,004	2.6%
5 GS-3	680,140,479	43,087,505	8,399,130	51,486,635	7.6%	6,726,858	1,143,864	7,870,723	1.2%
6 LP-4	346,739,156	10,750,484	9,949,844	20,700,328	6.0%	1,917,858	4,523,623	6,441,481	1.9%
7 IS-P	20,223,610	383,427	819,879	1,203,306	6.0%	(27,368)	336,998	309,630	1.5%
8 LP-5	173,341,229	18,733	8,474,987	8,493,720	4.9%	(187,042)	4,904,126	4,717,084	2.7%
9 IS-T	80,939,746	(564,896)	4,061,493	3,496,597	4.3%	(564,896)	390,228	(174,668)	-0.2%
10 LP-6	28,519,862	(97,808)	1,312,754	1,214,946	4.3%	(97,808)	384,184	286,376	1.0%
11 LPEP	4,690,679	90,802	367,477	458,279	9.8%	29,688	305,938	335,627	7.2%
12 ISA	5,597,112	84	-	84	0.0%	(241,668)	-	(241,668)	-4.3%
13 IS-1	148,538	12,701	2,049	14,750	9.9%	4,420	4,018	8,438	5.7%
14 BL	558,797	56,990	(1,446)	55,544	9.9%	24,263	8,079	32,342	5.8%
15 SA	4,260,246	372,717	50,790	423,507	9.9%	1,362,213	58,392	1,420,605	33.3%
16 SM	969,979	83,755	12,670	96,425	9.9%	312,997	14,337	327,333	33.7%
17 SHS	17,598,908	1,594,681	154,629	1,749,310	9.9%	5,631,815	175,100	5,806,915	33.0%
18 SE	922,509	43,568	48,131	91,699	9.9%	316,770	54,538	371,308	40.2%
19 TS	41,393	3,257	859	4,116	9.9%	9,637	974	10,611	25.6%
20 SI-1	21,160	1,870	234	2,104	9.9%	6,886	265	7,151	33.8%
21 GH-1	28,566,505	2,436,077	332,016	2,768,093	9.7%	493,192	1,208,189	1,701,382	6.0%
22 GH-2	6,106,273	534,741	69,780	604,521	9.9%	112,529	257,795	370,324	6.1%
23 Standby(LP5-S)	1,137,301	46,696	18,015	64,711	5.7%	10,439	10,444	20,883	1.8%
24 PRS	6,433,825	-	-	-	0.0%	-	-	-	0.0%
25 Total	2,729,907,742	162,345,030	58,926,027	221,271,057	8.1%	162,345,030	58,061,663	220,406,693	8.1%

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PPL Electric Utilities Corporation
 Summary of Impacts of Proposed TSC and Distribution Increases
 Total Distribution Increase assumed to be \$120 Million
 Reflects Distribution Charges for all customers; Transmission imputed for all customers

	(1) Total Present Revenues	(2) PPLICA Distribution Increase	(3) PPLICA Transmission Increase	(4) PPLICA Total Increase	(5) PPLICA % Increase
1 RS	1,081,597,743	105,137,279	42,861,753	147,999,032	13.7%
2 RTS	23,568,392	5,715,666	2,373,487	8,089,153	34.3%
3 RTD	420,490	43,010	17,599	60,609	14.4%
4 GS-1	217,363,810	2,592,043	(972,269)	1,619,774	0.7%
5 GS-3	680,140,479	984,910	1,143,864	2,128,774	0.3%
6 LP-4	346,739,156	501,925	4,523,623	5,025,548	1.4%
7 IS-P	20,223,610	(114,597)	336,998	222,401	1.1%
8 LP-5	173,341,229	(233,828)	4,904,126	4,670,298	2.7%
9 IS-T	80,939,746	(581,349)	390,228	(191,121)	-0.2%
10 LP-6	28,519,862	(101,117)	384,184	283,067	1.0%
11 LPEP	4,690,679	10,731	305,938	316,669	6.8%
12 ISA	5,597,112	(248,194)	-	(248,194)	-4.4%
13 IS-1	148,538	647	4,018	4,665	3.1%
14 BL	558,797	9,391	8,079	17,469	3.1%
15 SA	4,260,246	1,091,806	58,392	1,150,197	27.0%
16 SM	969,979	250,865	14,337	265,202	27.3%
17 SHS	17,598,908	4,513,865	175,100	4,688,965	26.6%
18 SE	922,509	253,890	54,538	308,427	33.4%
19 TS	41,393	7,724	974	8,698	21.0%
20 SI-1	21,160	5,519	265	5,784	27.3%
21 GH-1	28,566,505	124,938	1,208,189	1,333,127	4.7%
22 GH-2	6,106,273	28,506	257,795	286,301	4.7%
23 Standby(LP5-S)	1,137,301	6,371	10,444	16,816	1.5%
24 PRS	6,433,825	-	-	-	0.0%
25 Total	2,729,907,742	120,000,000	58,061,663	178,061,663	6.5%

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BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission)

v.)

PPL Electric Utilities Corporation)

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Docket No. R-00049255

Includes:
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and
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REBUTTAL TESTIMONY
AND EXHIBITS
OF
STEPHEN J. BARON

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ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

July 2004

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BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission)
)
 v.) Docket No. R-00049255
)
 PPL Electric Utilities Corporation)

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1 Specifically, I will respond to the testimony of OCA witness Roger Colton regarding
2 his recommendation to allocate Universal Service Program ("USP") expenses to all
3 rate schedules in the Company's class cost of service study. PPL's filed study, which
4 I generally support, has properly allocated USP related expenses only to the RS and
5 RTS rate schedules. Mr. Colton argues in his testimony that the USP represents a
6 "public good" and thus should be borne by all PPL customers. I do not agree with
7 that assertion. I will also respond to the testimony of OCA witness Richard Galligan
8 regarding his related proposal to allocate the USP on the basis of either rate schedule
9 kWh or revenues. I will show that Mr. Galligan's recommendation would result in a
10 substantial portion of the USP funding requirement be borne by PPL's large
11 customers. Many of these customers who are served directly from the transmission
12 system do not use the Company's distribution system (they are only responsible for
13 distribution costs associated with metering equipment).

14
15 In addition, I will respond to PennFuture witness John Hanger regarding his proposal
16 to double the funding level for the Sustainable Energy Fund ("SEF") and require
17 ratepayers to begin paying for this funding as part of their distribution rates. As I
18 will discuss, contrary to Mr. Hanger's assertion the SEF was intended to be self-
19 sustaining after the initial 6 year funding arrangement that was initiated in the
20 restructuring settlement. Ratepayers should not be required to fund the SEF through
21 additional charges added to their distribution rates. If the SEF were a voluntary
22 program, in which ratepayers could elect whether or not to participate and by how
23 much, PPLICA would not have an objection to the PennFuture proposal to increase

1 the target funding level for the SEF. However, PPLICA continues to oppose
2 including the SEF expenses as a cost of providing distribution service; it is not a
3 distribution cost and should not be charged to ratepayers in this manner.

4
5 Finally, I will respond to OTS witness Paul Yarolin regarding his recommendation
6 for allocating the distribution revenue increase authorized by the Commission in this
7 proceeding. Specifically, Mr. Yarolin recommends that the first \$83 million of any
8 distribution revenue increase be allocated in a multi-step fashion, which he describes
9 but does not quantify. He then proposes to allocate any additional revenue increase
10 (above \$83 million) on an equal percentage basis to all rate schedules. As I will
11 discuss, Mr. Yarolin's recommendation does not sufficiently mitigate the subsidies
12 currently being paid by PPL's largest customers.

13
14 **Q. Mr. Baron, other parties also submitted testimony regarding the allocation of**
15 **the ultimate distribution rate increase among rate schedules and the calculation**
16 **of the transmission service charge. Because you do not address those proposals**
17 **in this rebuttal testimony, should the Commission conclude that you agree?**

18 **A. No. I continue to support the proposals articulated on behalf of PPLICA in my direct**
19 **testimony.**

1 I. Response to OCA Witnesses Roger Colton and Richard Galligan

2

3 Q. Would you please respond to the proposal of OCA witnesses Colton and
4 Galligan to allocate USP expenses to all rate schedules in the Company's cost
5 of service analysis?

6 A. OCA witness Colton provides the support for the OCA's position to allocate USP
7 expenses to all rate schedules in the PPL distribution cost of service study. In its
8 filing in this case, PPL has allocated these expenses to the residential class, following
9 its traditional practice of using specific assignments for these types of customer
10 assistance programs. The USP is not a distribution system revenue requirement from
11 a cost of service standpoint.

12

13 Q. What are the primary arguments offered by Mr. Colton in support of his
14 recommendation to change the allocation of USP expenses?

15 A. His primary arguments are that the restructuring statute requires that the USP be in
16 the form of a non-bypassable charge and that the USP is a public good and should be
17 collected from all ratepayers. I will respond to each of these arguments.

18

19 Q. Does the requirement that the USP be in the form of a non-bypassable charge
20 also require that it be allocated to all rate schedules?

21 A. No. Mr. Colton appears to have taken the term "non-bypassable" out of context.
22 The Public Utility Code states

1 There are certain public purpose costs, including programs for low-
2 income assistance, energy conservation and others, which have been
3 implemented and supported by public utilities' bundled rates. The
4 public purpose is to be promoted by continuing universal service and
5 energy conservation policies, protections and services, and full
6 recovery of such costs is to be permitted through a nonbypassable
7 rate mechanism. (66 Pa C.S. § 2803(17))
8

9 The Commission shall ensure that universal service and energy
10 conservation policies, activities and services are appropriately funded
11 and available in each electric distribution territory. Policies, activities
12 and services under this paragraph shall be funded in each electric
13 distribution territory by nonbypassable, competitively neutral cost-
14 recovery mechanisms that fully recover the costs of universal service
15 and energy conservation services. (66 Pa. C.S. § 2804(9))
16

17 In the context of a regulatory environment in which there is retail competition, a non-
18 bypassable charge is one in which customers pay the charge whether they "shop" for
19 generation supply or take service under Provider of Last Resort ("POLR") rates from
20 an EDC. This generally would require that the charge be recovered in the
21 distribution rate that is paid by all customers in the class, both shopping and non-
22 shopping. It does not, however, imply one way or the other an allocation scheme in
23 which costs are assigned to all rate schedules. In context, it means that the USP costs
24 that were in the bundled rates for a particular customer class should be continued
25 after rate unbundling. It does mean, however, that if the USP is recovered only from
26 residential customers, then all residential customers should pay the costs.
27

28 **Q. Would you please respond to Mr. Colton's second argument in which he**
29 **classifies the USP as a public good that should be paid for by all customers?**

1 A. The concept of ascribing USP costs as a public good does not justify the allocation
2 of this cost to all rate schedules. First, and foremost Mr. Colton has not shown
3 that the USP is a public good. I do not dispute that the USP helps the public
4 because it provides benefits to some segments of the public, but it is not a public
5 good in the same manner that police, fire protection or the military are public
6 goods. These public goods are services provided by the government that cannot
7 realistically or feasibly be provided by individuals or private organizations alone.
8 A public good is "a good the consumption of which by one consumer does not
9 reduce the consumption by the other." USP does not qualify as a public good
10 under this definition.

11
12 Second, even if the USP is deemed to be a public good, this does not imply that it
13 should be allocated to all customers on the basis of the customer's size or the
14 amount of the customer's kWh usage. Even if all customers are responsible for the
15 USP, this does not mean that financial support for USP among customers should
16 be assigned on the basis of how much electricity a customer uses. Doing so turns
17 the USP into a form of graduated tax, graduated on the basis of each customer's
18 requirements for energy. This is a very poor example of graduated tax, if this is
19 the OCA's intent. The fact that an industrial customer in Pennsylvania consumes a
20 large amount of electricity does not imply that such a customer has the "ability to
21 pay" such a tax. The testimonies of individual PPLICA members have discussed
22 the competitive difficulties facing many industries in the state.

¹ MICROECONOMIC MODELS, K. C. Kogiku, Harper & Row, 1971.

1

2 **Q. Mr. Colton has also argued that all PPL customers receive benefits from the**
3 **USP in the form of potentially lower uncollectible expenses and lower call**
4 **center expenses. Would you respond to this argument?**

5 A. Though it may be true that the USP does reduce PPL uncollectible expenses and
6 call center expenses (I have not seen any evidence on this issue one way or the
7 other), these costs are either specifically assigned to rate schedules (uncollectible
8 amounts), or are allocated to residential, small commercial and industrial rate
9 schedules on the basis of the number of customers in these rate schedules. In fact,
10 Large C&I customers have a separate commercial and industrial hotline and do
11 not use the call center functions referenced by Mr. Colton. In the 2004 test year,
12 85% of uncollectible expenses were assigned to the residential class, while only
13 3.8% has been assigned to the combined large customer classes of IS-P, LP-4, LP-
14 5, LP-6, IS-T and LPEP. This was done based on the actual uncollectible accounts
15 for each rate schedule. Because only residential customers can request USP
16 assistance, any theoretical benefits produced by the USP would flow almost
17 entirely to the residential class. In no event would such benefits flow to all rate
18 schedules on a basis proportionate to kWh or revenues. His argument, even if it is
19 factually correct, does not support his allocation proposal; rather, it supports PPL's
20 USP allocation to the residential class.

21

22 **Q. How does OCA witness Richard Galligan propose to allocate USP costs to**
23 **rate schedules?**

1 A. Mr. Galligan proposes to assign USP costs on either a kWh or a revenue basis to
2 all rate schedules. His testimony does not present the impact of either of his
3 proposals, nor does he provide any theoretical basis for either allocation method.

4
5 The impact of his proposal for large industrial customers could be significant. To
6 illustrate the impact, I have developed an allocation of the \$21.4 million in USP
7 costs associated with the Company's WRAP and On-Track programs using a kWh
8 allocation, as suggested by OCA witness Galligan. This is shown in Baron
9 Exhibit__(SJB-1R). If a kWh allocation is used to allocate the USP costs, Rate
10 Schedule LP-5 would be assigned additional costs of \$1.882 million in USP costs,
11 compared to its present distribution revenues of \$1.659 million. PPL's proposed
12 total distribution rate revenue for Rate Schedule LP-5 is \$1.685 million, including
13 Price Response Service ("PRS") revenues. In other words, the reallocation of USP
14 costs to Rate Schedule LP-5 will double the PPL proposed distribution revenue
15 requirement for this customer class, amounting to an additional 113.5% rate
16 increase beyond the distribution increase already proposed by the Company. For
17 Rate Schedules LP-6 and IS-T, the increases would be 105% and 71.7%
18 respectively under Mr. Galligan's proposal.

19
20 Based on PPL's cost of service study, the actual cost to provide distribution service
21 to Rate Schedule LP-5 is only \$1.05 million (see Exhibit SJB-7 in PPLICA
22 Statement No. 1). PPL's proposed distribution rate for LP-5 is \$0.32 per kW, a
23 rate that already includes substantial subsidy payments by LP-5 customers. The

1 USP charge for Rate Schedule LP-5 (if based on a kWh allocation as suggest by
2 OCA witness Galligan) would result in an additional \$0.37 per kW month charge
3 (more than double the PPL proposed rate). This is obviously unreasonable and
4 should be rejected by the Commission. Transmission voltage rate schedules, such
5 as LP-5, LP-6, IST and LPEP have minimal distribution cost responsibility,
6 principally only metering costs. The OCA proposal would have the effect of
7 increasing the distribution revenue requirements by substantial amounts, based on
8 an unsupported theory that the USP is a public good that should be charged to
9 ratepayers on the basis of a customer's level of electricity consumption.

10
11 If the Commission finds that the USP expense should be assigned to all rate
12 schedules as a policy matter, it should be allocated on the basis of the number of
13 customers in each rate schedule, not on the basis of rate schedule kWh or
14 revenues, as suggested by Mr. Galligan.

15
16 **II. Response to PennFuture Witness John Hanger**

17
18 **Q. Will you please respond to the direct testimony of PennFuture witness Hanger**
19 **regarding his proposal to increase the proposed funding of the SEF by 100%**
20 **compared to PPL's proposal in this case?**

21 **A.** Yes. Mr. Hanger proposes to establish the SEF funding at a 0.2 mill per kWh rate
22 in this case, compared to PPL's funding proposal of 0.1 mills per kWh. He also
23 proposes to collect this SEF cost from all ratepayers, following the expiration of the

1 SEF collection provisions authorized in the 1998 PPL restructuring settlement at
2 Docket No. R-00973954.

3
4 First, as I discussed in my direct testimony, the proposed recovery of SEF expenses
5 as a distribution related revenue requirement should be rejected. The SEF is not
6 currently being funded by PPL's customers. Pursuant to the restructuring settlement,
7 PPL's shareholders have funded the SEF at a rate of 0.1 mills per kWh and will
8 continue to do so until the termination of such funding at year-end 2004. The
9 expectation is that the SEF will be self-sustaining, following the initial funding
10 provided by PPL shareholders.

11
12 **Q. Do you object to increased funding of the SEF if PPL's customers are not**
13 **required to pay for the SEF in rates?**

14 **A.** No. PPLICA opposes mandatory SEF funding by customers. If SEF funding is
15 established on a voluntary basis, by using a "check-off" provision on customer bills,
16 PPLICA would not oppose increasing the funding target. However, if the
17 Commission determines that customers should fund the SEF on a mandatory basis,
18 as proposed by PPL and PennFuture, then the funding level should not be increased,
19 at least for the mandatory portion of any such funding. My direct testimony
20 illustrates how, under the company's current proposal, the SEF would constitute a
21 disproportionate percentage of the distribution rate for Large C&I customers;
22 doubling the funding will magnify the impact.

1 Q. Mr. Hanger argues that customers receive benefits from the SEF in the form of
2 potentially lower distribution costs due to such projects as distributed
3 generation. Would you please respond to this argument?

4 A. One of Mr. Hanger's arguments in support of increased SEF funding is that
5 distribution reliability will increase as a result of the SEF and therefore PPL
6 customers should support the funding (Hanger Testimony at page 6, line 10).
7 However, he has not demonstrated that PPL customers will receive any
8 "distribution" reliability benefits from the SEF programs. Mr. Hanger provides no
9 studies in support of the assertion that demonstrable reliability benefits exist due
10 to the projects funded by the SEF. More importantly, even if there are such
11 benefits, the appropriate issue for the Commission to examine is whether such
12 benefits exceed the costs of the SEF payments to be made by PPL customers.
13 Clearly, if the SEF is assigned to all customers, as proposed by PPL, this
14 cost/benefit analysis should be reviewed on a rate schedule by rate schedule basis.
15 In particular, PPLICA members taking service on PPL Rate Schedules LP-5, LP-6
16 and IS-T do not use the PPL distribution system (their distribution costs are
17 limited to metering equipment). How can these customers benefit from asserted
18 distribution related reliability benefits? The answer is they cannot. Even
19 customers on Rate Schedules LP-4 and IS-P may experience little, if any,
20 distribution reliability benefit from the SEF projects.

21

1 Q. Mr. Hanger complains that the legislature has not provided taxpayer funding
2 for the SEF (page 5, line 23). Would you comment on this portion of his
3 testimony?

4 A. If the elected Legislature that represents the citizens of Pennsylvania has
5 determined not to "impose a tax" to fund the SEF (any expenditure approved by
6 the legislature effectively increases taxes over and above what they would
7 otherwise be without the tax), then why should the Commission impose an SEF
8 tax on PPL ratepayers? I believe that the answer is that the Commission should
9 not impose such an involuntary charge on all PPL ratepayers. Rather, the SEF
10 should be voluntary through a customer check-off approach on each monthly bill.

11
12 Q. Mr. Hanger, on page 8 at lines 21-23 of his testimony, discusses his
13 interpretation of the 1998 restructuring settlement with regard to the
14 expected termination of ratepayer (or PPL shareholder) SEF funding on
15 December 31, 2004. Would you please respond to his testimony on this issue?

16 A. Yes. Mr. Hanger argues that the 1998 settlement does not "require" that the SEF
17 become self-sustaining after the initial funding period expires in 2004. Although
18 Mr. Hanger may have an interpretation of the Commission's June 2, 2000 Order at
19 Docket No. R-00973954, the language of the document speaks for itself and seems
20 to be more consistent with the common understanding of "self-sufficient" or "self-
21 sustaining" (i.e., providing for itself without help or capable of maintaining itself
22 independently).

23

1 The available evidence supports the conclusion that the expectation of the parties,
2 at the time of the settlement, was that PPL/shareholder funding of the SEF would
3 expire at the end of 2004 absent any other Commission action. In the first annual
4 plan presented by the SEF upon its organization, it is clearly stated that utility
5 funding for the SEF would not continue beyond six years and the fund would have
6 to become self-sustaining. Specifically, the "July 1, 2000 – June 30, 2001 Annual
7 Plan" states on page 13 at section 3.1, as follows:

8 **We are further committed that the SEF monies will also be**
9 **sustainable. Although we do not provide a limited grants**
10 **budget as noted, our investments are into viable businesses and**
11 **projects that will provide a fair return to the SEF so that future**
12 **companies and projects can also be financed. This important**
13 **criterion will force us to be disciplined in our project selection**
14 **but is critical to our ability to leverage limited funds. We**
15 **anticipate that it will take as long as 20 years to effect**
16 **meaningful change in a legacy energy infrastructure that**
17 **developed over the previous 100 years. Ratepayer (sic)**
18 **financing is scheduled to end December 31, 2004. At that time,**
19 **our current forecasting indicates that we will (sic) \$9 million in**
20 **assets and an additional \$15 million in PRI accounts receivable.**
21 **The \$24 million pool of funds will be available to sustain the**
22 **SEF beyond the initial years and/or will be the foundation for**
23 **an accelerated program fueled by additional funds, from**
24 **whatever source. (emphasis added)**

25 The SEF's second annual plan for the period July 1, 2001 through June 30, 2002
26 contained a nearly identical paragraph on page 13, and also stated on page 3:

27 **The SEF is committed to continue its mission beyond the six**
28 **years of PPL funding. The Board will accomplish this goal by**
29 **structuring its program-related investments to realize a financial**
30 **return. It will also maximize the impact of its funds by bringing**
31 **other partners into its investments. The Fund also has developed**
32 **a responsible investment policy for its reserve funds that assures**
33 **continuity and supports its overall mission.**

1 Q. What conclusion do you draw from this evidence?

2 A. The expectation of the SEF itself in the year 2000 was that the fund would not
3 receive contributions from either PPL or its ratepayers after December 31, 2004.
4 This is the best indication of the original intention for the SEF.

5

6 **III. Response to Office of Trial Staff Witness Paul Yarolin**

7

8 Q. Have you reviewed the direct testimony of OTS witness Yarolin regarding the
9 allocation of any Commission authorized increase in distribution revenues to
10 rate schedules?

11 A. Yes. Mr. Yarolin recommends a multi-step process to allocate the Commission
12 authorized revenue increase in this case that is based in part, but only in part, on
13 moving rate schedule rates of return toward the system average rate of return (i.e.,
14 moving rates towards cost of service). His recommendation is as follows:

15

16 1. Increase residential Rate Schedule RS by approximately \$49.8
17 million.

18 2. Increase rate RTS to bring this schedule to a "0" rate of return, based
19 on a compliance cost of service filing.

20 3. Set rates for non-profit customers on rates GS-1 and GS-3 at the RS
21 rate level.

1 4. Allocate the remaining revenues, up to \$83 million, to all other rate
2 schedules to produce the same proportionate revenue increases as
3 proposed by PPL.

4 5. Allocate any additional Commission authorized revenue increase to
5 all rate schedules on an "across-the-board" basis.
6

7 **Q. Has Mr. Yarolin quantified the impact of his recommendation for any rate**
8 **schedule, other than rate RS?**

9 A. No. He has only quantified the impact on rate RS, assuming that the Company is
10 authorized an \$83 million increase. He has not provided any quantification of the
11 impact of his recommendation on other rate schedules at the \$83 million increase
12 level, nor has he quantified the impact of his proposal on any rate schedule, including
13 RS, of the Company's requested increase of \$163 million.
14

15 **Q. Do you agree with Mr. Yarolin's recommendation for the allocation of an**
16 **approved increase in distribution revenues?**

17 A. No. Though he has attempted to partially consider the test year cost of service
18 results in this case, he has not done so in a manner sufficient to mitigate large
19 subsidies in current rates.
20

21 **Q. Have you been able to quantify the impact of his proposal on all rate schedules?**

22 A. Because there are no cost of service results that directly correspond to the OTS's \$83
23 million revenue increase, I am not able to quantify the impact of his proposal at the

1 OTS's proposed increase level. However, I have developed a quantification of his
2 allocation recommendation under PPL's proposed increase in this case. Though I am
3 not endorsing the Company's revenue requirement request in this case, this analysis
4 of the impact of the OTS's proposal for allocating the increase is helpful in
5 understanding the problems with the OTS's allocation recommendation.

6
7 Baron Exhibit__(SJB-2R) shows the impact of Mr. Yarolin's revenue allocation
8 recommendation, assuming that PPL received its entire requested increase in this
9 case. As can be seen, the level of subsidies paid by many rate schedules increases
10 under the OTS's proposal. For example, the residential subsidy benefit received by
11 the residential class increases from \$51.3 million at present rates to \$61.1 million
12 under the OTS's proposal (priced out at the full PPL \$163 million increase request).
13 The OTS's recommendation does not reasonably consider the cost of service results
14 in this case and continues the large subsidies paid by some of PPL's customers,
15 principally those customers who take service directly from PPL's transmission
16 system and do not use distribution facilities (except for metering). The OTS's
17 recommendation on this allocation issue should not be accepted by the Commission.

18
19 **Q. Does that complete your testimony?**

20 **A. Yes.**

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

PPL Electric Utilities Corporation

)
)
)
)
)

Docket No. R-00049255

REBUTTAL EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

**J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA**

July 2004

RECEIVED

AUG 17 2004

PPL Electric Utilities Corporation
Impact of Universal Service Programs Allocation

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

	(1)	(2)	(3)	(4)
Rate Class	Present Revenues ¹	Annualized Sales @ Customer Level ²	USP Allocated on Sales	Percent of Present Revenues
1 RS	300,160	13,022,415	7,572	2.5%
2 RTS	3,566	406,662	236	6.6%
3 GS-1	63,426	2,059,192	1,197	1.9%
4 GS-3	86,060	8,816,408	5,126	6.0%
5 LP-4	21,730	5,393,258	3,136	14.4%
6 ISP	1,789	415,755	242	13.5%
7 LP-5	1,659	3,237,251	1,882	113.5%
8 IST	1,706	2,103,931	1,223	71.7%
9 LP-6	281	508,302	296	105.2%
10 LPEP	281	64,339	37	13.3%
11 ISA	621	227,439	132	21.3%
12 GH	6,464	431,555	251	3.9%
13 SL/AL	17,652	111,271	65	0.4%
14 L5-S	37	7,258	4	11.4%
15 Total	505,432	36,805,036	\$ 21,400	4.2%

¹ Annual Adjusted Sales of Electricity (Distribution) - Exhibit JMK-2, Pages 117-118, Line 8

² Exhibit JMK-2, Page 164

DOCUMENT
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AUG 18 2004

PPL Electric Utilities Corporation
 Summary of Subsidiaries under Present and Staff Proposed Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Rate Class	Rate Base	Present Return	Present Rate of Return	Present Subsidy	Staff Revenue Increase	Staff Income Increase	Staff Rate of Return	Staff Proposed Subsidy	% Change in Subsidy
1 RS	1,216,771	19,428	1.60%	(51,291)	97,378	53,392	5.98%	(61,110)	19.1%
2 RTS	41,367	(1,636)	-3.95%	(5,932)	2,984	1,636	0.00%	(6,593)	11.1%
3 GS-1	179,297	16,646	9.28%	17,580	16,448	9,018	14.31%	18,232	3.7%
4 GS-3	250,040	26,247	10.50%	30,048	34,483	18,907	18.06%	42,503	41.5%
5 LP-4	61,618	6,554	10.64%	7,561	8,474	4,647	18.18%	10,607	40.3%
6 ISP	3,796	549	14.46%	731	240	132	17.93%	636	-12.9%
7 LP-5	2,036	480	23.58%	730	(101)	(55)	20.86%	450	-38.4%
8 IST	716	624	87.15%	1,087	(625)	(343)	39.29%	399	-63.3%
9 LP-6	144	116	80.56%	201	(110)	(60)	38.55%	78	-61.1%
10 LPEP	825	92	11.15%	109	264	35	15.37%	100	-8.4%
11 ISA	284	306	107.75%	538	(44)	(24)	99.30%	469	-12.8%
12 GH	19,682	1,921	9.76%	2,101	2,350	1,289	16.31%	2,717	29.3%
13 SL/AL	66,001	677	1.03%	(3,469)	763	418	1.66%	(8,521)	145.6%
14 L5-S	177	10	5.65%	6	41	23	18.38%	31	453.3%
15 Total	1,842,754	72,014	3.91%	(0)	162,345	89,014	8.74%	0	

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 82381

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Gross Revenue Conversion Factor (calculated from Exh Future 1, Sch D-13, p.4 of 4 - 164,438/90162)

DOCUMENT

PPLICA Statement No. 1S

8-12-04 TES
HBL

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission)

v.)

) Docket No. R-00049255

PPL Electric Utilities Corporation)

DOCKETED

AUG 18 2004

SURREBUTTAL TESTIMONY
OF
STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE
("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

August 2004

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SECRETARY'S BUREAU

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission)
)
 v.) Docket No. R-00049255
)
 PPL Electric Utilities Corporation)

SURREBUTTAL TESTIMONY OF STEPHEN J. BARON

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Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I previously submitted direct and rebuttal testimony.

Q. What is the purpose of your Surrebuttal Testimony?

1 A. I am responding to the rebuttal testimony of PPL witness Douglas Krall, Office of
2 Trial Staff (“OTS”) witness Gary Yocca, Public Lighting User Group (“PLUG”)
3 witness John Bradley, Office of the Consumer Advocate (“OCA”) witness
4 Richard Galligan, Office of the Small Business Advocate (“OSBA”) witnesses
5 Robert Knecht and Mark Ewen, Citizens for Pennsylvania’s Future
6 (“PennFuture”) witness John Hanger and Sustainable Energy Fund of Central
7 Eastern Pennsylvania (“SEF”) witness Thomas Tuffey.

8
9 With regard to PPL witness Krall’s testimony, I will address the Company’s
10 response to the modifications that I proposed in my direct testimony regarding the
11 Transmission Service Charge (“TSC”) tariff. In that testimony, I proposed a cost
12 based recovery tariff that reflects the underlying basis for the transmission charges
13 from PJM to PPL. The Company, through the testimony of Mr. Krall, has
14 addressed the PPLICA TSC proposal and I will respond to Mr. Krall’s testimony
15 on this issue. I will also address Mr. Krall’s rebuttal testimony in which he
16 responds to PPLICA’s opposition to the Company’s proposed Distribution System
17 Improvement Charge (“DSIC”).

18
19 With regard to OTS witness Yocca’s testimony, I will respond to his comments on
20 the PPLICA proposed TSC tariff and the proposal that I made in my direct
21 testimony regarding the appropriate allocation of any Commission authorized
22 distribution revenue increase.

1
2 I will briefly respond to the rebuttal testimony of PLUG witness Bradley regarding
3 his testimony that the lighting class is paying a rate of return in excess of the
4 system average based on the last bundled class cost of service. As I will discuss,
5 the cost of service study that he references is based on the results of a bundled
6 cost study that reflected PPL cost of service results for a test year in effect prior to
7 retail restructuring in 1998. It does not provide any evidence relevant to the
8 reasonableness of distribution rates in this proceeding, which relies on a 2004 test
9 year.

10
11 I also will respond to OCA witness Galligan and OSBA witnesses Knecht and
12 Ewen regarding their rebuttal testimony on the allocation of the distribution
13 revenue increase to rate schedules.

14
15 Finally, I will address the assertions made by SEF witness Tuffey and PennFuture
16 witness Hanger regarding mandatory customer funding of the SEF.

17
18 **Response to PPL Witness Douglas Krall**

19
20 **Q. Would you please respond to Mr. Krall's testimony regarding the**
21 **modifications to the TSC that you recommended in your direct testimony?**
22

1 A. In my direct testimony, I proposed modifications to PPL's proposed TSC to reflect
2 the underlying cost basis on which PJM actually bills PPL for transmission
3 charges. Mr. Krall has not challenged the reasonableness of the underlying cost
4 basis for the PPLICA proposed TSC tariff. Rather, PPL's opposition to the
5 PPLICA proposal is focused on issues of administrative ease (the principal
6 concern of PPL) or on the impact of the allocation on certain rate schedules,
7 which also is the principal concern of other parties such as the OCA and OTS.

8
9 First, PPLICA appreciates PPL's supportive response to our proposal for
10 modifying the TSC to reflect the underlying cost basis for transmission charges.
11 Though, as I will discuss, PPLICA does not agree with all of Mr. Krall's
12 alternative proposals to accommodate the concerns that PPLICA has with the
13 Company's TSC, PPLICA does recognize that the Company has made some
14 movement in its position towards a cost based recovery mechanism advocated by
15 PPLICA.

16
17 **Q. What is your understanding of PPL's alternative proposal for the recovery of**
18 **transmission charges through the TSC?**

19 A. Though it is not entirely clear whether PPL is actually agreeing to an alternative
20 TSC tariff, it is my understanding that the Company would accept a TSC that is
21 based on cost of service. This would follow my direct testimony proposal to
22 separately allocate the demand and energy related transmission charges from PJM

1 to individual PPL rate schedules. However, the Company appears to be
2 continuing its opposition to a "5 CP demand based" rate design for large
3 customers who are interval metered or who can be billed based on "tagged
4 demand". PPLICA continues to strongly recommend that a demand/energy
5 transmission and ancillary service rate structure be implemented for Rate
6 Schedules LP-4, LP-5, LP-6, IS-P, IS-T and LPEP. Once the transmission costs
7 have been properly allocated to rate schedules using the appropriate
8 demand/energy classification (as I discussed in my direct testimony), there is no
9 reason why individual customers cannot be billed on the same basis using their
10 tagged 5 CP demands and actual kWh usage.

11
12 **Q. Mr. Krall has expressed some concern regarding the stability of using the**
13 **PJM based "5 CP" demands for recovery of TSC costs. Would you please**
14 **comment on this issue?**

15 **A.** Yes. Mr. Krall has shown that due to the shifting in PPL zonal peaks between
16 summer and winter, there are differences in the allocation of cost using the 5 CP
17 allocator. Though such changes may occur, this is the basis for the charges that
18 PPL receives from PJM. If PPL has a concern about this cost allocation, the
19 appropriate remedy is to seek a change in the PJM Open Access Transmission
20 Tariff ("OATT"). Unless and until such a change is made, it is appropriate for
21 PPL to charge its retail customers on the same basis as it is charged for
22 transmission services from PJM.

1
2 Perhaps more importantly, there is also a competitive generation supply market
3 impact associated with this issue. PPL's customers can shift annually (and
4 actually more frequently subject to potential payments under the Generation Rate
5 Adjustment rider) between Provider of Last Resort ("POLR") and Electric
6 Generation Supplier ("EGS") service. Since an EGS will pay for transmission
7 service associated with such a customer on the basis of the customer's tagged "5
8 CP" demand, there would be a mismatch between the customer's transmission
9 charges under the TSC and the transmission costs borne by an EGS in the event
10 that the customer switches from PPL POLR service, unless the TSC is constructed
11 in a manner that the demand costs are recovered using the same "5 CP" basis.
12 This is a potentially unintended consequence of PPL's kWh recovery mechanism
13 and one that is not ameliorated by the Company's alternative proposal, which
14 properly incorporates a demand allocation to rate schedules but improperly
15 continues to rely on a kWh rate recovery mechanism within rate schedules. It is
16 PPLICA's position that customers should be indifferent as between POLR and
17 EGS service with regard to distribution and transmission rates; a kWh recovery
18 mechanism for demand related transmission costs would not meet this
19 requirement.

20
21 **Q. Does PPLICA agree with PPL's proposal to implement a reconciliation**
22 **mechanism on a "group" basis, using a kWh recovery?**

1
2 A. Yes. If the costs are allocated properly among rate schedules and the rates are
3 designed to include a demand component and energy component as explained in
4 my direct testimony, then PPLICA is willing to agree with PPL's reconciliation
5 proposal to group rate schedules using the same grouping as approved for the
6 CTC recovery and applying the reconciliation on a kWh basis. Though this is a
7 departure from a pure cost based tariff, PPLICA recognizes that the trade-off
8 between administrative ease and cost of service principles for the reconciliation
9 charge (as opposed to the actual transmission charge itself) would provide a basis
10 for the Company's proposal. Moreover, as I explained in my direct testimony,
11 designing the retail transmission rates for large customers on a demand/energy
12 basis to reflect proper cost causation should minimize the need for and impact of
13 any reconciliation.

14
15 **Q. Do you have any comments on Mr. Krall's testimony in response to your**
16 **opposition to the Company's DSIC charge?**

17 A. Yes. PPLICA continues to oppose the DSIC. Mr. Krall has not shown that there
18 is a financial necessity that could justify the DSIC. Though his observations
19 regarding the aging of PPL distribution facilities may be correct, this does not
20 provide evidence of changed circumstances that would require a change in the
21 regulatory process affecting PPL's distribution rates. In addition, I am advised by
22 counsel that Mr. Krall's suggestion that customers could challenge the DSIC level

1 or PPL's earnings through a "standard complaint" shifts the burden of proof from
2 PPL to the customer.

3
4 With regard to the Company's proposal to modify the allocation of the DSIC
5 revenue requirement to recover the cost on a revenue allocation basis, this
6 proposal would at least reflect a DSIC mechanism that is more equitable from a
7 rate structure standpoint. Though I continue to oppose the DSIC for the reasons
8 that I discussed in my direct testimony, if the Commission does approve the
9 DSIC, the Company's revised rate recovery approach (on a distribution revenue
10 basis) should be adopted, in lieu of a kWh recovery mechanism.

11
12 **Response to OTS Witness Gary Yocca**

13
14 **Q. Have you reviewed OTS witness Yocca's rebuttal testimony in which he**
15 **responds to your recommendations regarding modifications to PPL's**
16 **proposed TSC and the allocation of any approved increase in distribution**
17 **revenues?**

18 **A.** Yes. Mr. Yocca presents rebuttal testimony addressing each of these issues, as
19 well as the proposal that I made to implement additional rate adjustments in the
20 two years following this case in order to fully eliminate the subsidies in PPL's
21 distribution rates. I will respond to each of these issues.

1 Q. Would you please respond to Mr. Yocca's testimony regarding your
2 proposed modifications of the Company's TSC?

3 A. Yes. Mr. Yocca's position appears to be that there should be a kWh based
4 recovery mechanism (as originally proposed by PPL) because the Company has
5 not filed a fully allocated cost of service study for transmission costs in this case.
6 First of all, by advocating a kWh allocation and recovery mechanism, Mr. Yocca
7 is implicitly arguing that such a rate is just and reasonable. In fact, the evidence in
8 this case demonstrates that a kWh based allocation and recovery mechanism is not
9 just and reasonable because it ignores the underlying cost basis for transmission
10 charges from PJM to PPL. Mr. Yocca has presented no evidence that the rate
11 design that I proposed in my direct testimony for recovering transmission costs via
12 a TSC is not reasonable. Rather he argues that the Commission should not make
13 a decision on the allocation of transmission costs without a cost of service study
14 and then concludes, without foundation, that a kWh allocation and recovery
15 mechanism is therefore appropriate.

16
17 Q. Is there a need to perform a transmission cost of service study for the PJM
18 related transmissions expenses at issue?

19 A. No. There is no need to perform a fully allocated cost of service study on PJM
20 pass-through costs. The PJM tariff and the corresponding billing provide the
21 exact cost basis for charging PPL's retail customers. This is the underlying basis
22 for PPLICA's transmission TSC tariff, which is essentially a cost of service based

1 rate. Moreover, PPLICA's TSC tariff proposal assures that customers will pay the
2 same level of transmission charges to PPL as the POLR supplier that their EGS
3 will incur if they purchase competitive generation supply.

4
5 **Q. How would one perform a fully allocated cost of service study on the PJM**
6 **charges?**

7 A. First, each transmission expense would be classified on the basis of customer,
8 energy and demand related. Next, these classified costs would be allocated to
9 each rate schedule on the basis of how PPL incurs these costs from PJM. This is
10 exactly the analysis that I performed in my direct testimony to develop the
11 PPLICA proposed TSC. I classified each of the PJM costs into energy and
12 demand related costs (there are no customer costs) and then allocated them to rate
13 schedules. There is essentially no difference between the PPLICA proposed TSC
14 and a cost of service study based rate. If the PJM transmission charges are
15 charged to ratepayers on the same basis as these costs are incurred by PPL, then
16 there are no subsidies by definition. There is no need to perform any additional
17 cost analysis. What we do know is that PPL's PJM related costs are not incurred
18 solely on the basis of customer kWh use. Mr. Yocca himself does not dispute this
19 fact, yet he apparently endorses PPL's proposed TSC which blatantly ignores that
20 fact.

21

1 Q. Would you please respond to Mr. Yocca's testimony regarding your proposal
2 to allocate any approved distribution revenue increase in a manner designed
3 to reduce current subsidies by 50%?

4 A. Mr. Yocca disagrees with the proposal because of the impact on residential
5 customers and because the cost of service study on which I developed my
6 recommendation does not reflect any revenue requirement adjustments that the
7 Commission may ultimately adopt. With regard to his first concern, the
8 residential class is currently paying only about 85% of the costs that PPL incurs in
9 providing residential distribution service. This underpayment (at current revenue
10 requirements) coupled with the Company's original \$163 million proposed
11 increase results in a large deficit for the residential class, which must be made up
12 by either charging residential customers for the costs they impose on the system,
13 or charging other customers for a portion of the residential class responsibility for
14 these costs. The PPLICA proposal is designed to address the subsidy problem in a
15 gradual manner.

16
17 Q. What is the distribution revenue increase proposed for RS customers under
18 the PPLICA plan, assuming that PPL receives its entire \$163 million
19 increase?

20 A. As I discussed in my direct testimony, PPLICA is proposing to reduce current
21 subsidies by 50% at proposed rates, which will result in a total residential increase

1 of 12.5%, assuming that the Company receives its entire requested revenue
2 increase (PPLICA Statement No. 1, page 42, Table 6).

3
4 **Q. What is your response to Mr. Yocca's statement that the cost of service study**
5 **will not reflect adjustments that the Commission may make in its decision in**
6 **this case?**

7 A. Though this observation is not incorrect, it is always the case that a filed cost of
8 service study will not reflect the final revenue requirement determination made by
9 the Commission in its order. Nonetheless, the filed cost study does provide
10 necessary information regarding the balance between rate schedule revenues and
11 costs for the test year that should be used to allocate any approved increases.
12 Without a compliance cost study, there can never be a perfect match between the
13 two. However, this does not change the basic principle that I am recommending,
14 which is that subsidies need to be reduced in this case for the Company's
15 distribution rates. If the Commission ultimately decides to modify the Company's
16 filed cost of service studies and/or adjusts PPL's proposed revenue increase, it is
17 not likely that this will have a material effect on the relative rates of return for
18 each rate schedule.

19
20 Based on Mr. Yocca's position, no cost of service study could ever be used to set
21 rates because it may not comport with the final Commission approved revenue
22 increase. This is always the case in a rate case. Mr. Yocca's comments do not

1 address the underlying principle that I am recommending to the Commission; that
2 is, that distribution rates should move towards cost of service. Ironically, this
3 appears to be the same general principle that is being advocated by OTS witness
4 Yarolin, at least with respect to the residential class. As I demonstrated in my
5 rebuttal testimony, the OTS is proposing a larger increase for residential
6 customers (at the \$163 PPL revenue increase level) than is being proposed by
7 PPL.
8

9 **Q. Mr. Yocca objects to your proposal to phase-in additional rate changes over**
10 **a two- year period, following this case, in order to fully eliminate subsidies.**
11 **Would you comment on this testimony?**

12 A. I am proposing a phase-in of the increases and decreases necessary to move rates
13 to cost of service. Absent this approach, it would either be necessary to eliminate
14 all of the subsidies in this single case and thus produce possible rate shock, or
15 ignore the subsidies altogether until some future distribution rate case. This later
16 result would continue the payment of substantial subsidies by large customers of
17 the Company for potentially many years into the future. A phase-in to achieve
18 cost based rates is the best approach to addressing these concerns. Essentially,
19 PPL's rates will not be just and reasonable until the implementation of the third
20 step of the PPLICA proposed rate adjustments. Finally, I have been advised by
21 PPLICA counsel that the Commission has the discretion to implement a phase-in
22 mechanism such as we have proposed.

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Response to PLUG Witness John Bradley

Q. Have you reviewed PLUG witness Bradley's testimony regarding the allocation of distribution revenues?

A. Yes. Mr. Bradley opposes the PPLICA proposed allocation methodology on the grounds that the distribution cost of service study on which it is based (PPL's filed study) is an inappropriate vehicle to measure the reasonableness of distribution rates by rate schedule. Rather, Mr. Bradley appears to argue that the appropriate basis to assess the reasonableness of test year 2004 unbundled distribution rates is to examine PPL's bundled cost of service study that existed at the time of restructuring in 1998 (a study that was actually developed for a PPL rate case in the mid-1990's, almost 10 years ago).

It should be obvious why it is inappropriate to consider, as evidence in this case, the results of a cost of service study that: 1) is nearly 10 years old, and 2) reflects PPL revenue requirements for generation, transmission and distribution. The issue in this case is the reasonableness of the Company's distribution revenue requirements (transmission revenue requirements are established pursuant to an FERC tariff). The distribution revenue requirements in the prior, bundled cost of service study are not at issue in this case; rather, test year 2004 costs are at issue and should be the basis for assessing the reasonableness of PPL's distribution

1 rates compared to cost of service. The PUC should not “rebundle” rates in this
2 proceeding. In addition, the other unbundled rate elements (including any
3 unspecified subsidies that Mr. Bradley may believe exist) have been approved by
4 the Commission as just and reasonable.
5

6 **Response to OCA Witness Richard Galligan**
7

8 **Q. Have you reviewed the rebuttal testimony of OCA witness Galligan on cost of**
9 **service and distribution revenue allocation issues?**

10 A. Yes. Mr. Galligan has addressed a number of issues related to the Company’s
11 cost of service study, as well as the revenue distribution recommendation that I
12 presented in my direct testimony.
13

14 **Q. Would you please respond to Mr. Galligan’s rebuttal positions regarding the**
15 **allocation of distribution revenue?**

16 A. First, Mr. Galligan raises the time-honored position that the Company’s cost of
17 service study is incorrect and therefore the subsidy conclusions drawn from the
18 study are also incorrect. Though I have not specifically addressed the Company’s
19 cost of service study, I have concluded that it is a reasonable basis for assessing
20 distribution related rate schedule rates of return and whether these rates are just
21 and reasonable. Based on my review, which I discuss in detail in my direct
22 testimony, there are substantial subsidies being paid by larger PPL customers on

1 Rate Schedules LP-4, LP-5, LP-6, IS-P, IS-T and LPEP. Mr. Galligan has not
2 presented any evidence, to my knowledge, which would materially change this
3 conclusion. In particular, his arguments regarding the classification of some
4 distribution costs as demand related would have no impact on the cost of service
5 for Rate Schedules LP-5, LP-6, IS-T and LPEP. These rates do not use the
6 distribution system, except for metering costs, which are not affected by the cost
7 classification issue raised by Mr. Galligan. As I discussed in my direct testimony,
8 all of these rate schedules (including LP-4 and IS-P) are paying substantial
9 subsidies that should be addressed in this rate case.

10
11 This is the first opportunity since the beginning of retail competition to address
12 this problem, a period of more than 5 years. If nothing is done in this case to
13 begin moderating the substantial imbalances in PPL's distribution rates, it may be
14 years until another opportunity to fix this problem is available.

15
16 **Q. Mr. Galligan has raised the impact of the PPLICA TSC tariff proposal as a**
17 **reason to oppose your subsidy reduction approach to allocate the**
18 **distribution revenue increase. Would you respond to this testimony?**

19 A. The PPLICA transmission rate design recommendation is completely independent
20 of the Company's distribution cost of service study. Rather, it is based on an
21 analysis of the cost drivers associated with PPL's transmission service from PJM.
22 It does not affect the reasonableness of PPL's distribution rates, relative to cost of

1 service, which is the appropriate basis to evaluate distribution revenue allocation
2 proposals. The rates are unbundled and should be addressed separately.
3

4 **Q. Would you please respond to Mr. Galligan's testimony regarding the**
5 **proposed PPLICA TSC tariff?**

6 A. Many of the arguments raised by OCA witness Galligan are similar to those of
7 OTS witness Yocca, and therefore my response to Mr. Yocca on this subject is
8 applicable to Mr. Galligan's testimony as well. Mr. Galligan does not challenge
9 the underlying cost basis for PPLICA's transmission rate design. The Company is
10 proposing to collect revenues for its PJM transmission charges on a dollar for
11 dollar basis. There are no cost of service studies associated with these costs, and
12 there does not need to be as I previously explained. The PPLICA rate design is
13 effectively a cost of service based recovery mechanism. The transmission charges
14 from PJM are incurred to meet customer loads and energy requirements, based on
15 various charges tied to each of these cost drivers. Mr. Galligan does not dispute
16 this underlying cost basis for the PPLICA rate design proposal. Rather, he
17 focuses on the impact - he doesn't like the results implied by a rate design that
18 tracks PJM's charges to PPL for transmission service.
19

20 **Q. Does his reference to a vintage PPL cost of service study, based on bundled**
21 **rates that are not in evidence in this case have any relevance to the**
22 **reasonableness of your transmission rate design recommendation?**

1 A. No. The answer is obvious. It has no more relevance than citing a cost of service
2 study from Indiana or California - it is simply irrelevant to this case.
3

4 **Response to OSBA Witnesses Robert Knecht and Mark Ewen**
5

6 **Q. Have you reviewed the rebuttal testimony of OSBA witnesses Knecht and**
7 **Ewen regarding the PPLICA proposed TSC tariff and distribution revenue**
8 **allocation?**

9 A. Yes. The OSBA witnesses generally support the PPLICA TSC proposal, but have
10 recommended an alternative demand allocation approach based on a 5-year rolling
11 average to compute rate schedule demands. While PPLICA appreciates the
12 OSBA support for a cost based TSC, and recognizes the stability concerns raised
13 by the OSBA witnesses, the use of a 5-year average demand does not adequately
14 deal with the problem of creating a revenue neutral transmission rate for
15 customers, whether they shop with an EGS for generation supply or take POLR
16 service from PPL. The proper venue for addressing the PJM allocation method is
17 the Federal Energy Regulatory Commission ("FERC"), where issues concerning
18 the PPL OATT can be addressed. To the extent that the Pennsylvania
19 Commission adopts a transmission cost allocation method that differs from the
20 underlying cost basis for the PJM charges to PPL, it will create a mismatch that
21 will potentially affect the decisions of customers as between shopping and taking

1 POLR service from PPL. As a result, PPLICA continues to support the TSC
2 proposal that I developed in my direct testimony.

3
4 **Responses to SEF witness Tuffey and PennFuture witness Hanger**

5 **Q. Have you reviewed the rebuttal testimony of SEF witness Tuffey and**
6 **PennFuture witness Hanger related to the projects that the SEF has**
7 **supported?**

8 A. Yes. Both witnesses object to the categorization of SEF as a research and
9 development venture and attempt to explain how the projects supported by the
10 SEF benefit PPL's ratepayers.

11
12 **Q. Does this testimony change your conclusion that SEF funding should not be**
13 **included in customers' rates?**

14 A. No. The proponents of the funding have failed to establish that there are
15 demonstrable benefits for ratepayers and that those benefits outweigh the costs
16 that are proposed to be imposed on ratepayers.

17
18 **Q. Do you have any comments on witness Hanger's assertion that SEF is a**
19 **"public good"?**

20 A. My rebuttal testimony regarding why universal service programs are not "public
21 goods" is equally applicable to SEF.

22

1 Q. Does that complete your testimony?

2 A. Yes.

8-7-04 JES
LH86

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY)
COMMISSION)

v.)

) Docket No. R-00049255

PPL ELECTRIC UTILITIES)
CORPORATION)

DOCKETED

PP&L INDUSTRIAL CUSTOMER)
ALLIANCE)

2004

v.)

) Docket No. R-00049255C0002

PPL ELECTRIC UTILITIES)
CORPORATION)

Includes
Exhibits
JH1
Through
JH8

DOCUMENT

DIRECT TESTIMONY
AND EXHIBITS
OF
JENNIFER HUNSPERGER

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

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2004 AUG 17 AM 9:49

PA 300
SECRETARY'S BUREAU

June 2004

**TESTIMONY BY JENNIFER HUNSPERGER
PRAXAIR, INC.**

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

2 A. My name is Jennifer Hunsperger. My business address is 175 East Park Drive,
3 Tonawanda, NY 14151.

4
5 **Q. By what company are you employed?**

6 A. I am employed by Praxair, Inc. ("Praxair").

7
8 **Q. How long have you worked for Praxair?**

9 A. I have worked for Praxair for over nine (9) years.

10
11 **Q. What is your current position with Praxair?**

12 A. I am currently Energy Manager, Northeast Region, for Praxair.

13
14 **Q. What are your duties in your current position?**

15 A. I purchase power for Praxair facilities in the Northeast and I participate in state
16 and regional industrial groups on behalf of Praxair.

17
18 **Q. What is your educational and employment background with Praxair?**

19 A. I have a bachelors of science in chemical engineering from the Pennsylvania Sate
20 University. I joined Praxair's Service Company, UCISCO, as a Technical Sales
21 representative in 1995. I spent two and a half years selling industrial gases to the
22 steel, refining and chemical industry. In 1998 I started working for Praxair's

1 North American Industrial Gas Division as an Account Manager, calling on the
2 pharmaceutical, refining and chemical industry. I transferred to the Energy
3 Management Department in 2001.
4

5 **Q. Does Praxair have a facility located in the service territory of PPL Electric**
6 **Utilities Corporation ("PPL")?**

7 A. Yes. Praxair has two air separation facilities, one in Hatfield and one in
8 Stockertown, which are located within PPL's service territory. Both facilities
9 purchase service from PPL on Rate Schedule IS-T (Interruptible Service -
10 Transmission). The facility employs approximately 60 workers.
11

12 **Q. Please describe Praxair's operations at this facility.**

13 A. Our Hatfield and Stockertown plants are merchant air separation facilities. We
14 compress and cool atmospheric air to separate it into its primary gases – nitrogen,
15 oxygen and argon. The nitrogen is further cooled/compressed to a temperature of
16 -320°F, at which point it liquefies. Praxair can then transport the liqui-fied gases
17 to its customers.
18

19 Customers such as Praxair that purchase service from PPL at transmission level
20 voltage install and own various equipment at the site to transform that electricity
21 into lower voltages that can be used in manufacturing processes. To provide the
22 Commission with a visual perspective of the investment that 69 KV customers

1 must make, attached to my testimony are a series of pictures depicting the stages
2 in the transformation process.

3
4 The first picture [PPLICA Exhibit __ (JH-1)] provides an overview of the
5 equipment outside Praxair's facility where PPL's system ends and our system
6 begins. The electricity travels from PPL's transmission lines on the right side of
7 the photograph into Praxair's "Rack and Contacts." Exhibit __ (JH-2) shows
8 PPL's 69KV line. Exhibit __ (JH-3) provides another view of Praxair's rack. The
9 power flows from PPL's 69 KV line to Praxair's rack, and then through oil circuit
10 breakers located at the base of the rack [PPLICA Exhibit __ (JH-4)]. After the oil
11 circuit breakers, the electricity goes to Praxair's 69KV transformer, which
12 converts the power to 13.8 KV [PPLICA Exhibit __ (JH-5)]. The electricity then
13 flows through switchgear [PPLICA Exhibit __ (JH-6)] and to transformers to
14 convert the power to 2400 V or 480V, both of which are shown on Exhibit (JH-7).
15 The facility also has 12 _mini transformers.

16
17 The only equipment owned by PPL in this process are the 69KV transmission
18 lines [Exhibit __ (JH-2)] and the meter [Exhibit _ (JH-8)]. Praxair owns all of the
19 other equipment.

20
21 **Q. What issues will you address in your testimony?**

22 **A.** I will address the proposed transmission rates in PPL's filing.

23

1 Q. Please describe the current business environment in the industrial gases
2 industry.

3 A. Electricity represents an extremely large proportion (i.e., 70%) of an air
4 separation company's variable costs. As a result, Praxair is highly sensitive to
5 energy prices and could be greatly affected by PPL's proposed distribution and
6 transmission rates. Although distribution and transmission may be smaller
7 portions of the rate than generation supply, it is still important to minimize this
8 portion of customers' rates and to base this portion on the legitimate cost to serve
9 the customer. Praxair operates in a highly competitive environment in which
10 Praxair must compete with other air separation companies, some of which may
11 still be enjoying capped rates. As a result, it is critical to Praxair that PPL's
12 distribution rates be maintained at levels that are as low as possible. Otherwise,
13 Praxair may be placed at a competitive disadvantage relative to air separation
14 companies with lower electricity transmission or distribution costs. Since power
15 costs play an important role in an air separation company's ability to compete
16 even slightly higher power costs, relative to a competitor, at a facility handicap
17 the ability to compete for consumer's business. In addition, because electricity
18 costs are such a major production input, our customers will ultimately face higher
19 industrial gas prices if our electricity costs increase.

20

1 **Q. What types of customers purchase the products produced at the facility?**

2 A. Pharmaceutical, food processors, hospitals, universities, steel companies,
3 chemical companies, refineries, nuclear and coal power generation companies and
4 environmental companies purchase product manufactured at these locations.

5

6 **Q. Have you calculated the projected increase to Praxair's transmission rates as
7 of January 1, 2005?**

8 A. Yes. The per kWh transmission charges that we will pay to PPL when we
9 purchase POLR service are proposed to increase by 56%, from the current level
10 for Rate IS-T of \$0.00357 per kWh to a projected level of \$0.00564. Obviously,
11 this is a large increase and it could be even larger if PPL requests a transmission
12 rate increase from the Federal Energy Regulatory Commission.

13

14 **Q. Can you provide an estimate of the annual impact of this proposed
15 transmission rate increase?**

16 A. Although I cannot use information from the Praxair facilities due to
17 confidentiality concerns, I can provide information regarding the impact of this
18 transmission rate increase on a typical air separation facility. Based on my
19 experience, air separation facilities typically operate at a load factor of
20 approximately 90%. Based on this average load factor, I calculate that the impact
21 on a 10 MW facility to be approximately \$163,199 in additional transmission
22 charge payments each year $[(\$0.00564 \text{ per kWh} - \$0.00357 \text{ per kWh}) \times (10,000$

1 kW x 90% x 8760 hours/year)]. The increase for a 20 MW facility would be
2 approximately \$326,398 per year.

3
4 **Q. Does Mr. Baron provide an alternative Transmission Service Charge**
5 **("TSC") that would reduce this increase?**

6 A. Yes. It is my understanding that Mr. Baron's alternative TSC would reduce the
7 annual transmission charge responsibility for higher load factor customer such as
8 Praxair. Mr. Baron's TSC is designed to charge POLR customers the same
9 transmission and ancillary service costs that the EGS would pay to PJM if the
10 customer purchased competitive supply.

11
12 **Q. Do you have any other comments on Mr. Baron's TSC proposal?**

13 A. Yes. Because Mr. Baron's proposal bases the retail TSC on the same
14 methodology that an EGS will use to calculate my transmission and ancillary
15 services charges if I purchase competitive supply, I think that Mr. Baron's
16 proposal will allow customers such as Praxair to more readily compare EGS
17 offers to the POLR rates.

18
19 **Q. What would you like for the PUC to do?**

20 A. I would like for the PUC to adopt Mr. Baron's alternative TSC.

21
22 **Q. Does this conclude your testimony?**

23 A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

**PENNSYLVANIA PUBLIC UTILITY)
COMMISSION)**

v.)

) Docket No. R-00049255

**PPL ELECTRIC UTILITIES)
CORPORATION)**

**PP&L INDUSTRIAL CUSTOMER)
ALLIANCE)**

v.)

) Docket No. R-00049255C0002

**PPL ELECTRIC UTILITIES)
CORPORATION)**

**EXHIBITS OF
JENNIFER HUNSPERGER**

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

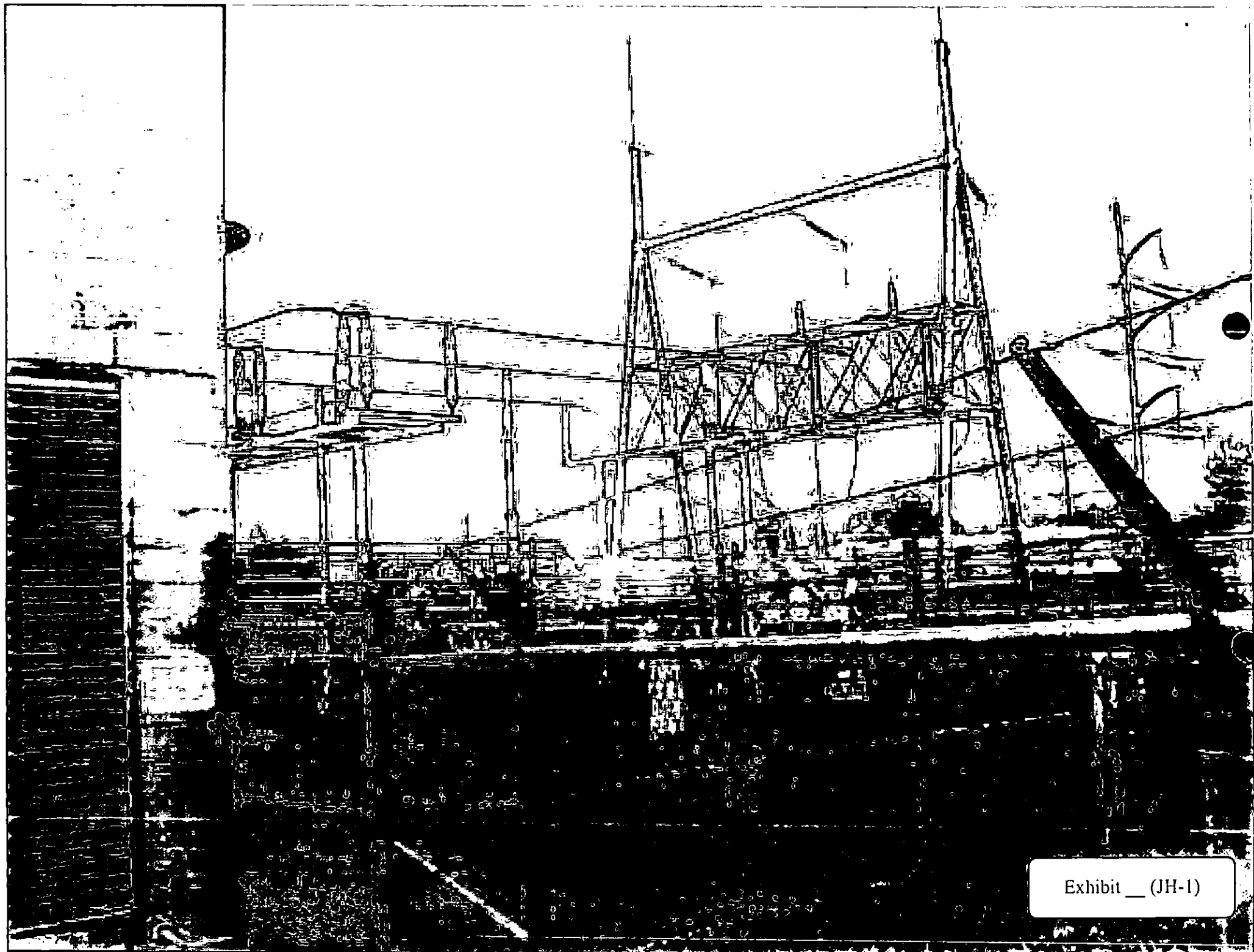


Exhibit __ (JH-1)

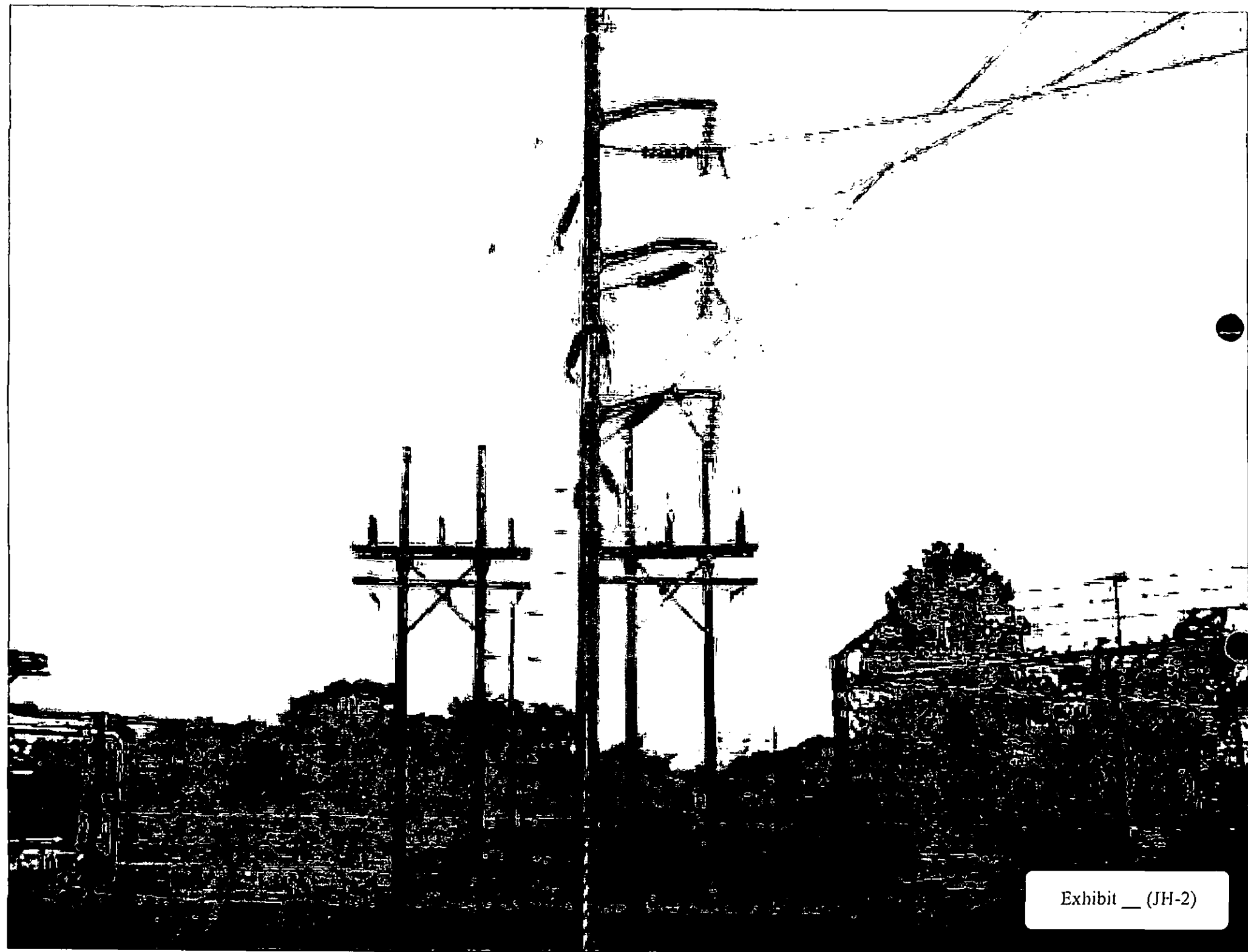


Exhibit __ (JH-2)

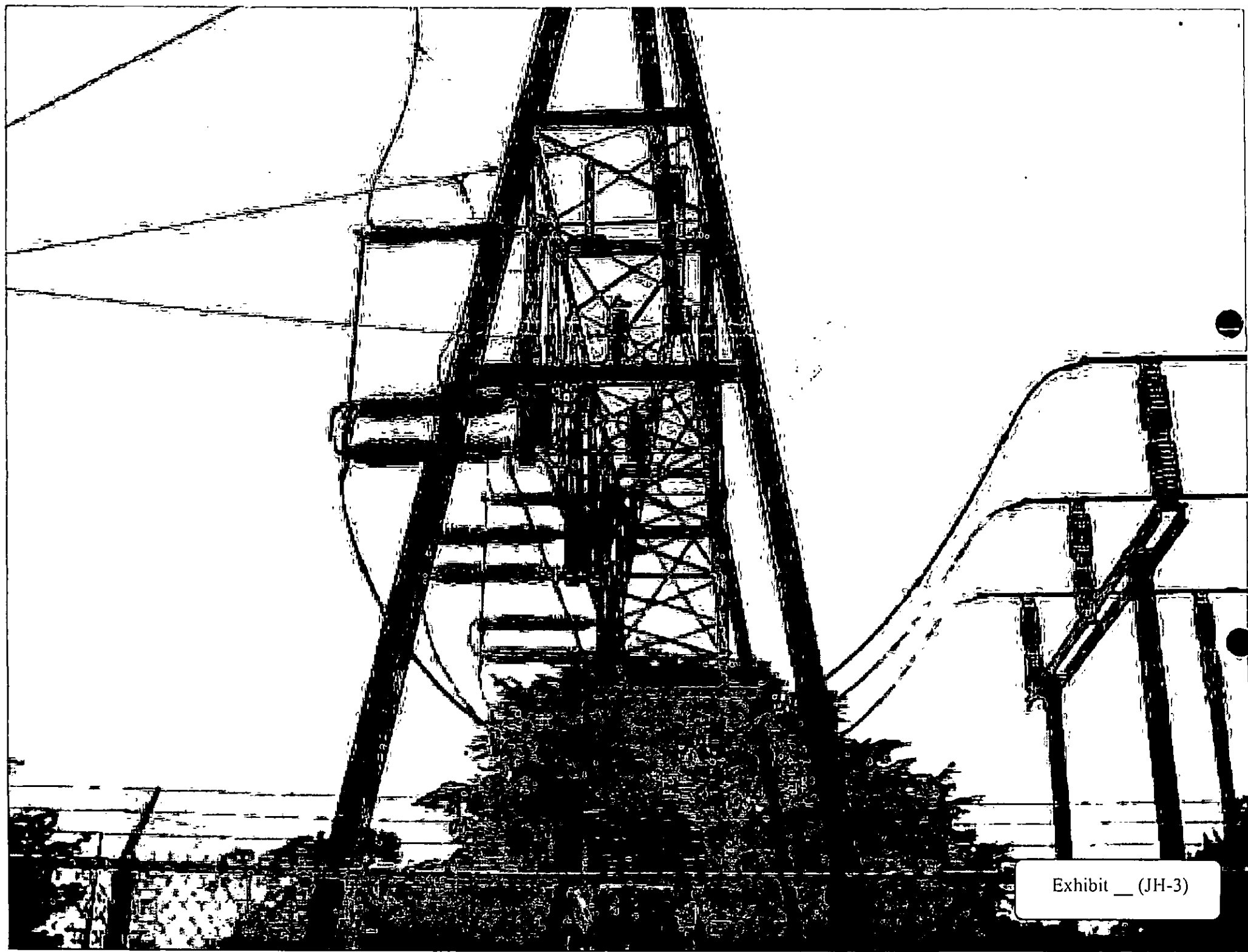


Exhibit __ (JH-3)

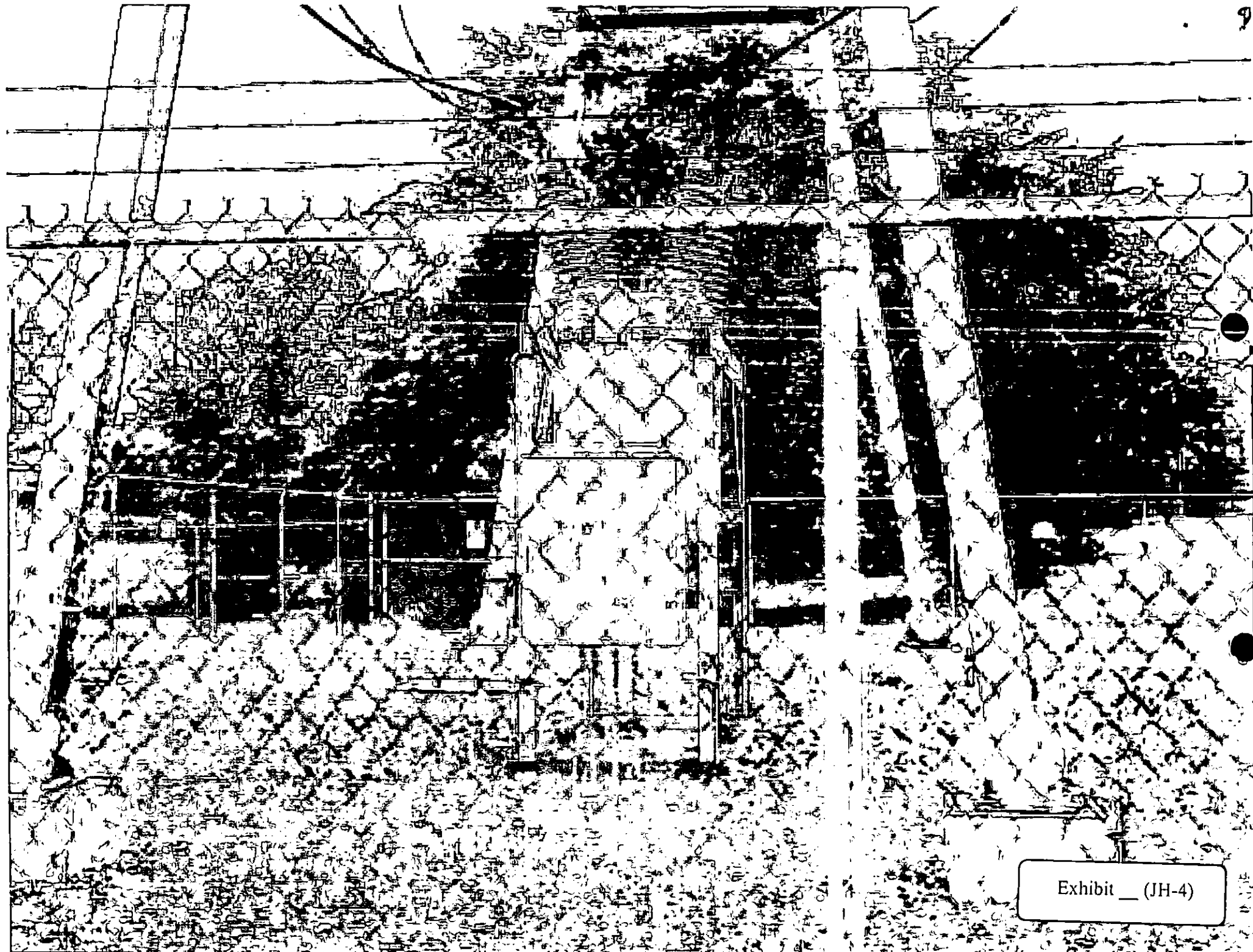


Exhibit _ (JH-4)

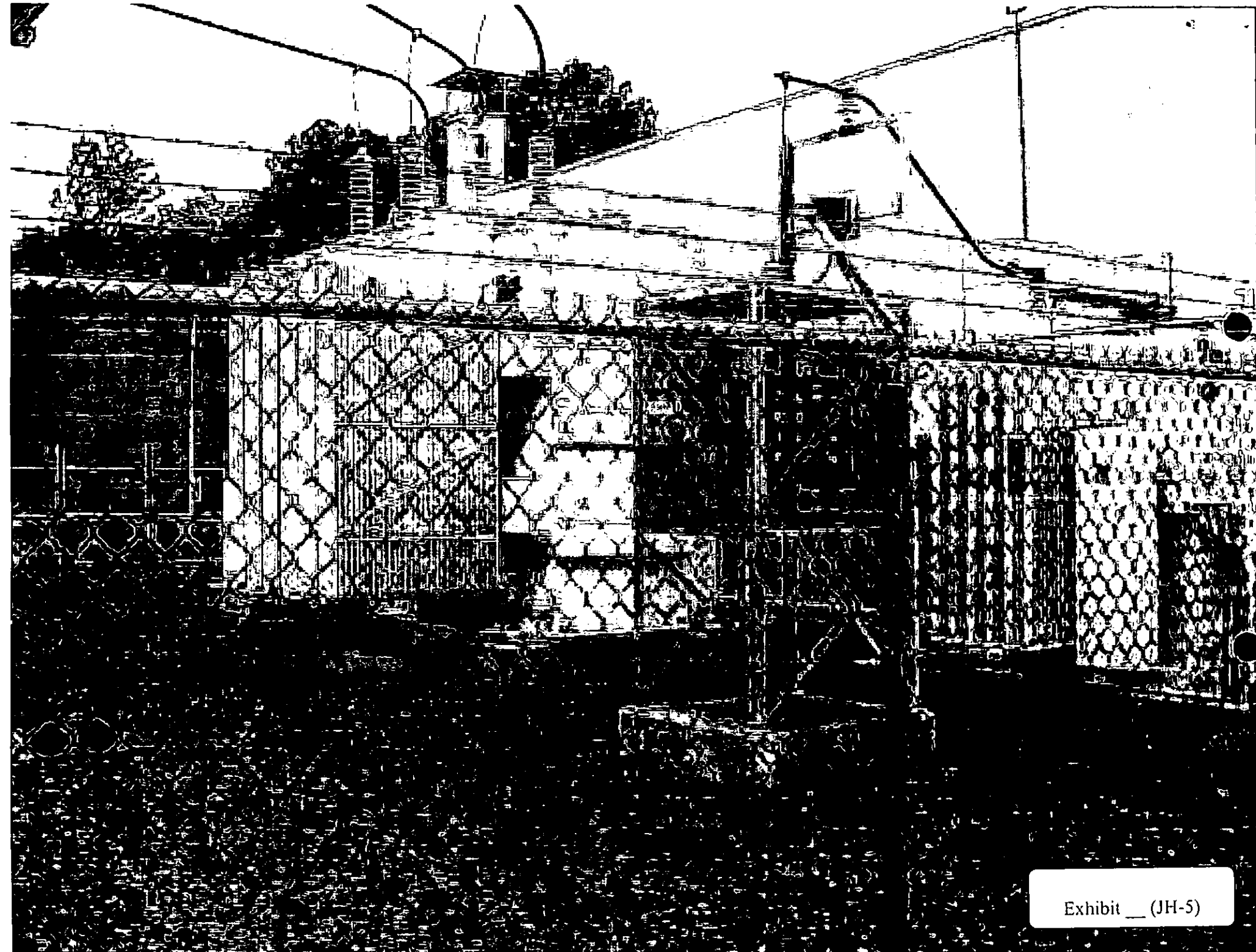


Exhibit __ (JH-5)

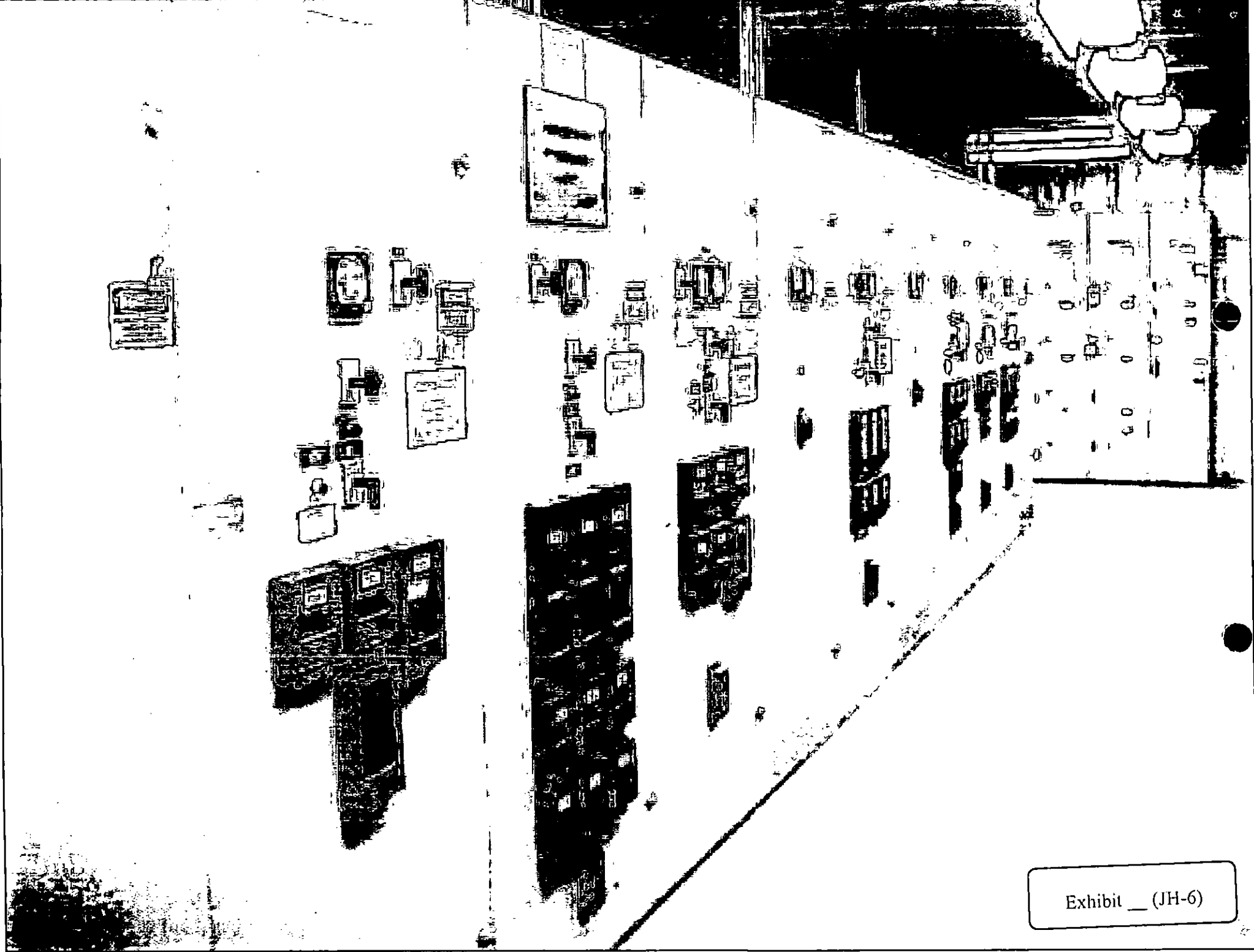


Exhibit __ (JH-6)

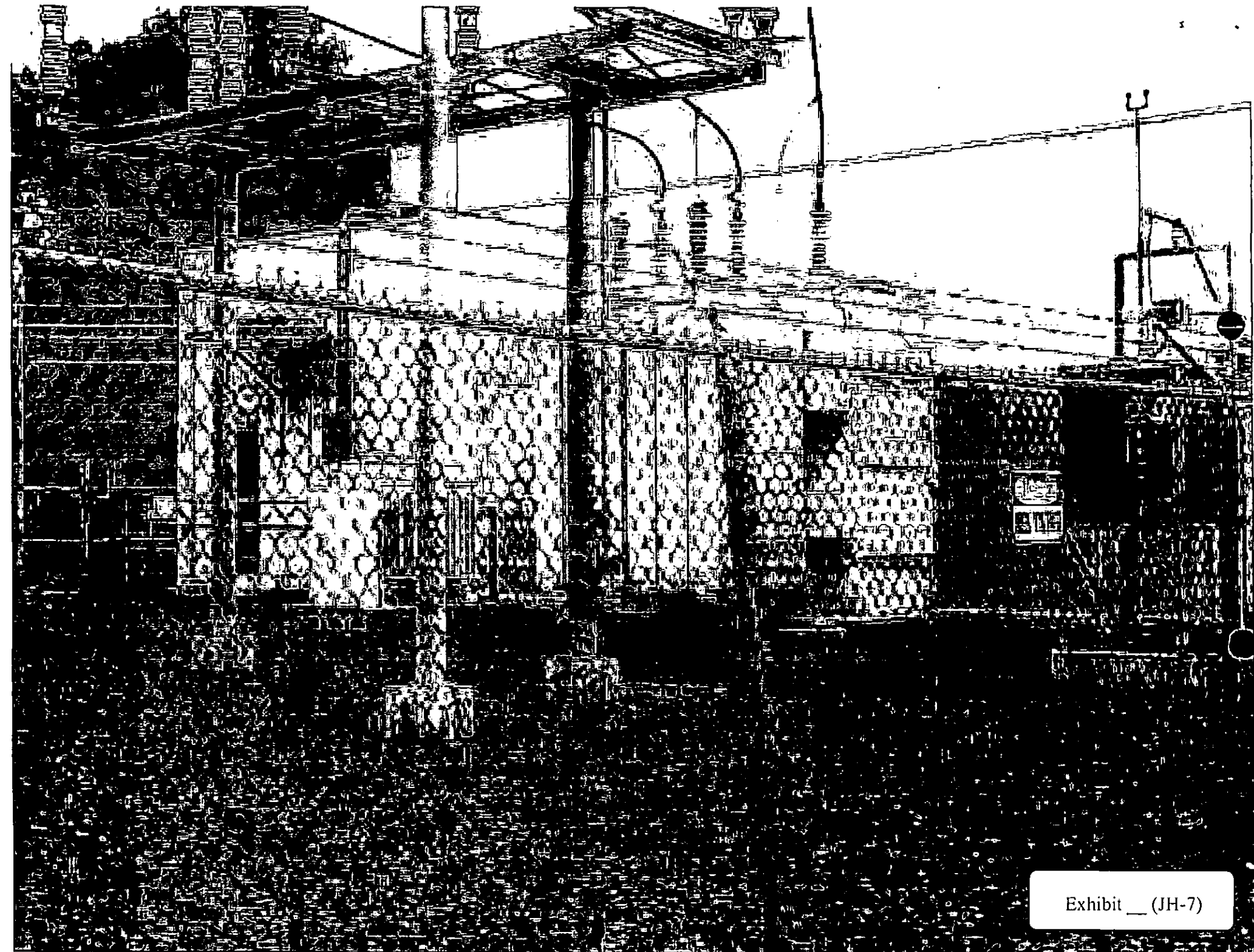


Exhibit __ (JH-7)

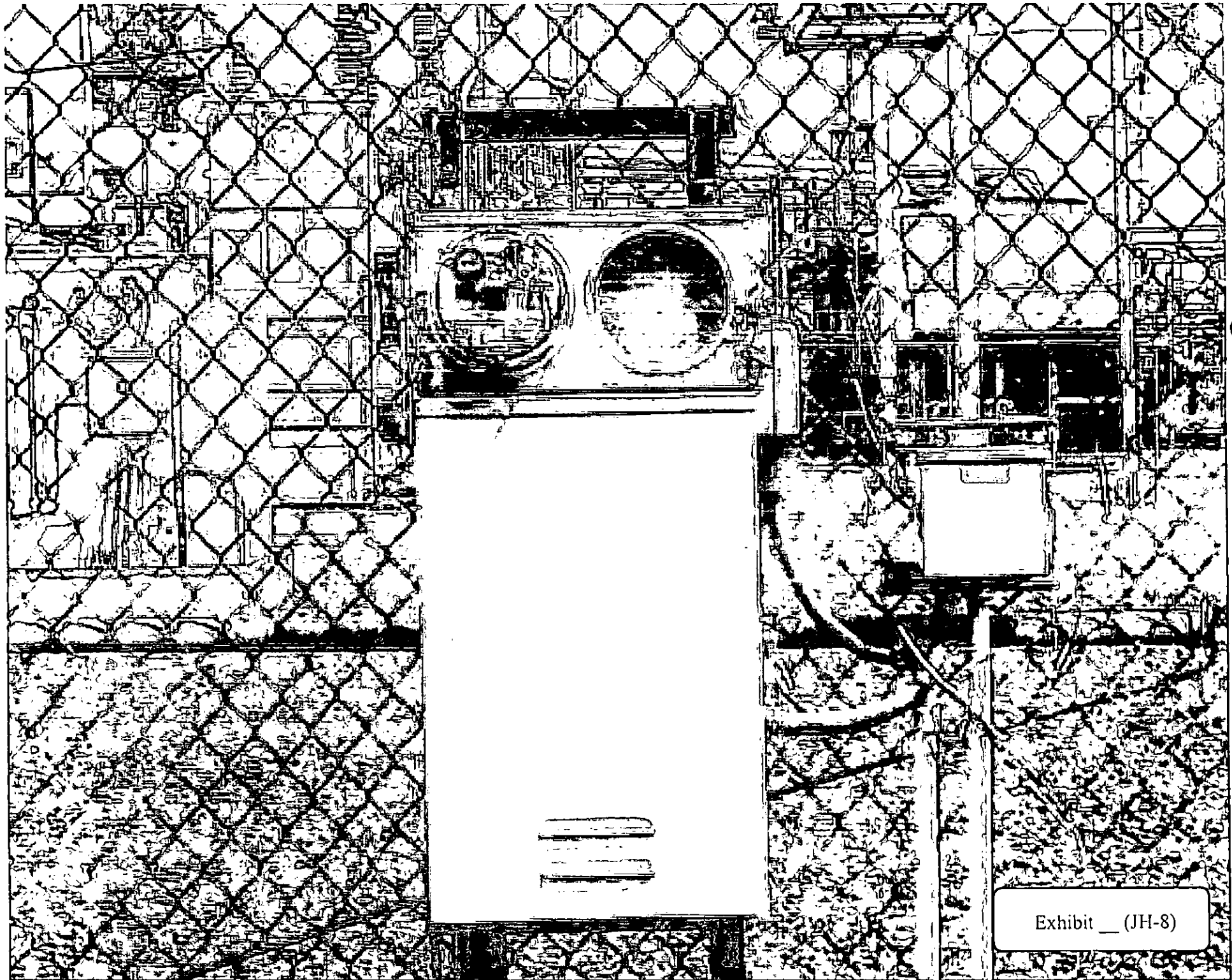


Exhibit __ (JH-8)

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Includes

Exhibits

LS1

and

LS2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY)
COMMISSION)

v.) Docket No. R-00049255

PPL ELECTRIC UTILITIES)
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PP&L INDUSTRIAL CUSTOMER)
ALLIANCE)

v.) Docket No. R-00049255C0002

PPL ELECTRIC UTILITIES)
CORPORATION)

DOCKETED
AUG 18 2004

DOCUMENT

DIRECT TESTIMONY
AND EXHIBITS
OF
LARRY STALICA

ON BEHALF OF THE
PP&L INDUSTRIAL CUSTOMER ALLIANCE

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FA PUC
SECRETARY'S BUREAU

**TESTIMONY BY LARRY STALICA
BOC GASES**

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

2 A. My name is Larry Stalica. My business address is 575 Mountain Avenue,
3 Murray Hill, NJ 07974.

4

5 **Q. By what company are you employed?**

6 A. I am employed by BOC Gases ("BOC"), subsidiaries of The BOC Group, Inc., a
7 worldwide industrial gases, vacuum technologies and distribution services
8 company with operations in more than 50 countries and annual sales of \$5.5
9 billion. BOC operates over 50 manufacturing facilities across the United States
10 and Canada with a total electrical load of approximately 500 MW.

11

12 **Q. How long have you worked for BOC?**

13 A. I have worked for BOC for over three years.

14

15 **Q. What is your current position with BOC?**

16 A. I am currently Manager – Energy and Regulatory Affairs.

17

18 **Q. What are your duties in your current position?**

19 A. In my current position, I manage energy procurement and regulatory affairs for
20 BOC's plants in the Northeast and Midwest United States.

21

1 **Q. What is your educational and employment background prior to joining**
2 **BOC?**

3 A: I received my B.S. in Electrical Engineering from the Pennsylvania State
4 University in 1989. I also graduated from the United States Navy's Nuclear
5 Power School, and was a Certified Engineer in the Department of Energy's Naval
6 Reactors Program, which operates and maintains the power plants of the Navy's
7 nuclear fleet. Prior to joining BOC in 2001, I was Manager - Energy, Facilities,
8 and Maintenance – Americas Tube Operations for Thomson Consumer
9 Electronics. In this position, I managed energy procurement and facility issues
10 for Thomson's television picture tube plants across North America. Thomson
11 Consumer Electronics is a division of Thomson Multimedia, a worldwide
12 consumer electronics company with annual sales of \$9.3 billion. Prior to joining
13 Thomson in 1996, I was employed for seven years by Knolls Atomic Power
14 Laboratory in Schenectady, New York.

15

16 **Q. Please describe the industry in which BOC operates.**

17 A. BOC produces nitrogen, oxygen, argon, and other atmospheric gases through an
18 energy-intensive air separation process. We meet the industrial gas needs of
19 customers in such industries as metals, chemicals, glass, medical, and electronics,
20 just to name a few.

21

22 **Q. Does BOC have a facility located in the service territory of PPL Electric**
23 **Utilities Corporation ("PPL")?**

1 A. Yes. BOC operates and is a part owner (with Air Products and Chemicals, Inc.)
2 of a joint venture air separation plant located at the former Bethlehem Steel
3 facility in Bethlehem.

4
5 **Q. On what rate schedules does BOC receive service from PPL?**

6 A. The plant purchases electricity from PPL on Rate Schedule IS-T (Interruptible
7 Service-Transmission).

8
9 **Q. Please provide some background information regarding the facility.**

10 A. The Bethlehem facility, which is the home of BOC's National Operation Center,
11 employs approximately 140 workers. BOC purchases approximately \$750,000 in
12 annual services and goods from the local community. In addition, BOC pays over
13 \$100,000 in state and local taxes at the Bethlehem facility.

14
15 **Q. What distribution facilities does PPL have in place to serve BOC?**

16 A. BOC receives service from PPL at transmission level voltage (i.e., 69 kV), then
17 we convert the electricity to voltage levels usable at our facility. BOC owns the
18 equipment that converts the electricity from 69 kV to these voltages. PPL owns
19 our meter, however, as well as the short line that connects the meter to PPL's
20 transmission system. Attached to this testimony as PPLICA Exhibits ___ (LS-1)
21 and (LS-2) are photographs showing the PPL metering equipment. Exhibit (LS-1)
22 shows the meter house and Exhibit (LS-2) shows the actual meter.

1 **Q. If all interclass subsidies are removed from PPL's distribution rates, what is**
2 **the appropriate cost-based distribution rates for the BOC facility?**

3 A. Based on the calculations performed by PPLICA witness Stephen J. Baron, which
4 are set forth in PPLICA Exhibit ___ (SJB-7), if the Commission accepts all
5 aspects of PPL's filing but modifies the distribution rates to remove all interclass
6 subsidies, the distribution rate for Rate Schedule IS-T will be \$0.453 per kW-
7 month. For Rate Schedule IS-T, this rate is multiplied by the customer's billing
8 demand, which is determined primarily based on the firm power level for the
9 facility. The firm power level is the amount of electricity usage that the customer
10 may continue using when PPL calls an interruption.

11
12 Because electricity consumption data is highly confidential in the air separation
13 industry, I will use a hypothetical facility to illustrate the impact. A typical air
14 separation facility may have a billing demand of 1,000 kW. The annual
15 distribution charges for the hypothetical facility would be \$5,436 under the cost-
16 based rates, compared to \$11,184 under PPL's proposed distribution rates. In
17 other words, the continued subsidies in the proposed distribution rate doubles the
18 customer's annual distribution payment.

19
20 **Q. What is your opinion of PPL's proposal to charge BOC (or any customer) a**
21 **rate that recovers twice PPL's actual cost to serve the account?**

22 A. Despite PPL's proposed reduction in distribution rates for IS-T customers, PPL
23 continues to charge BOC more than the actual cost of serving BOC. Under PPL's

1 proposed rates BOC continues to subsidize PPL's costs of serving other
2 customers. This is inequitable and unreasonable.

3
4 **Q. What is the current financial climate in the air separation industry?**

5 A. The air separation industry is highly competitive. Electricity comprises
6 approximately two-thirds of BOC's production costs. Because electricity is such a
7 large portion of our costs, it is important for distribution service to be
8 appropriately priced, even though distribution service is the smallest portion of
9 our bill. With the narrow profit margins existing in our industry, it is critical to
10 BOC's financial health that BOC secure electric service at the lowest rates
11 possible. Otherwise, BOC may lose business to other air separation companies
12 with lower costs.

13
14 **Q. What action would you like the Commission to take concerning PPL's**
15 **request?**

16 A. Ultimately, I would like the PUC to require PPL to further reduce the rates it
17 applies to BOC to a level more closely related to PPL's actual costs of serving
18 BOC. PPL proposes to remove some of the subsidization by reducing the per unit
19 distribution rate for Rate Schedule IS-T; however, the rate still remains twice as
20 high as it should be. I realize that the PUC is unlikely to require PPL to make
21 such a dramatic change all at once, however. Accordingly, I would like the PUC
22 to require PPL to implement the first step in the process by reducing the
23 distribution rate for Rate Schedule IS-T as proposed in the Company's testimony

1 and then to complete the process in accordance with Mr. Baron's phase-down
2 plan, which was submitted in this proceeding as PPLICA Exhibit ____ (SJB-10)
3 and his testimony.
4

5 **Q. Are you also concerned about PPL's proposed transmission rate increase?**

6 A. Yes, I am. According to Mr. Baron's calculations, BOC will be forced to increase
7 its transmission rate payments by 56%, if PPL's proposal is approved. For a
8 typical 25MW air separation plant with a 95% load factor, this 56% increase
9 equates to approximately \$440,000 per year.
10

11 **Q. Has Mr. Baron proposed any way of mitigating this increase?**

12 A. Yes, he proposes an alternative Transmission Service Charge ("TSC") that would
13 reduce the increase by calculating and designing the rate to reflect the kW and
14 kWh billing that PJM uses to charge PPL for transmission and ancillary services.
15

16 **Q. Would you like to make any other comments regarding Mr. Baron's TSC
17 proposal?**

18 A. Yes. I think Mr. Baron's TSC proposal would actually help to promote
19 competition. Mr. Baron would calculate the TSC using the same methodology
20 that an electric generation supplier ("EGS") within the PJM would use to
21 determine BOC's charges for transmission and ancillary services. This design
22 would make comparing EGS offers and PPL POLR rates more efficient for BOC
23 and other customers, thereby encouraging competition. It also provides an

1 incentive for BOC to operate the plant efficiently and to minimize our usage
2 during the peak periods, which benefits the reliability of the electric system.

3

4 **Q. Would you like to address any other issues?**

5 A. No.

6

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

8 A. Yes.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY)
COMMISSION)

v.)

) Docket No. R-00049255

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ALLIANCE)

v.)

) Docket No. R-00049255C0002

PPL ELECTRIC UTILITIES)
CORPORATION)

EXHIBITS OF
LARRY STALICA

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

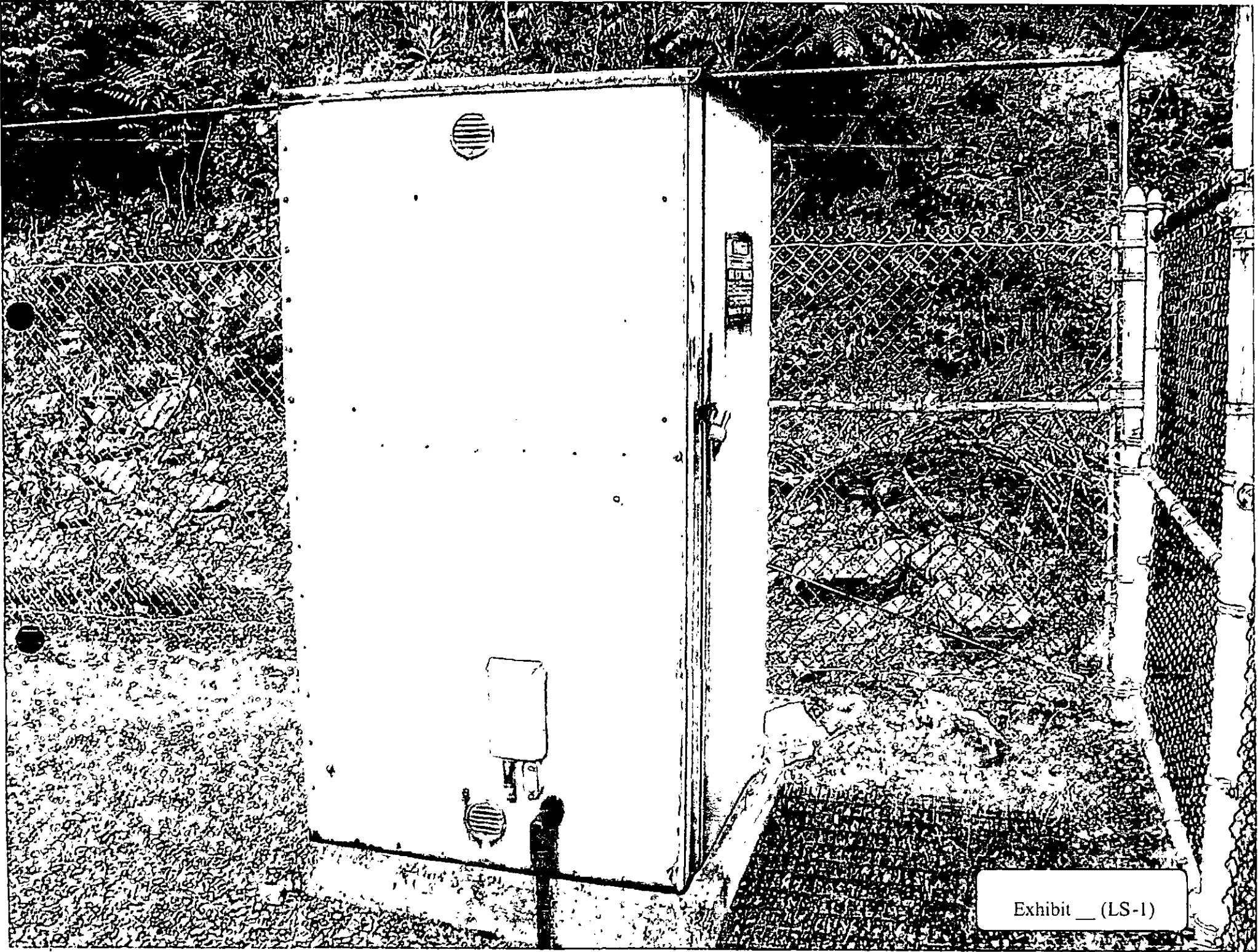


Exhibit __ (LS-1)

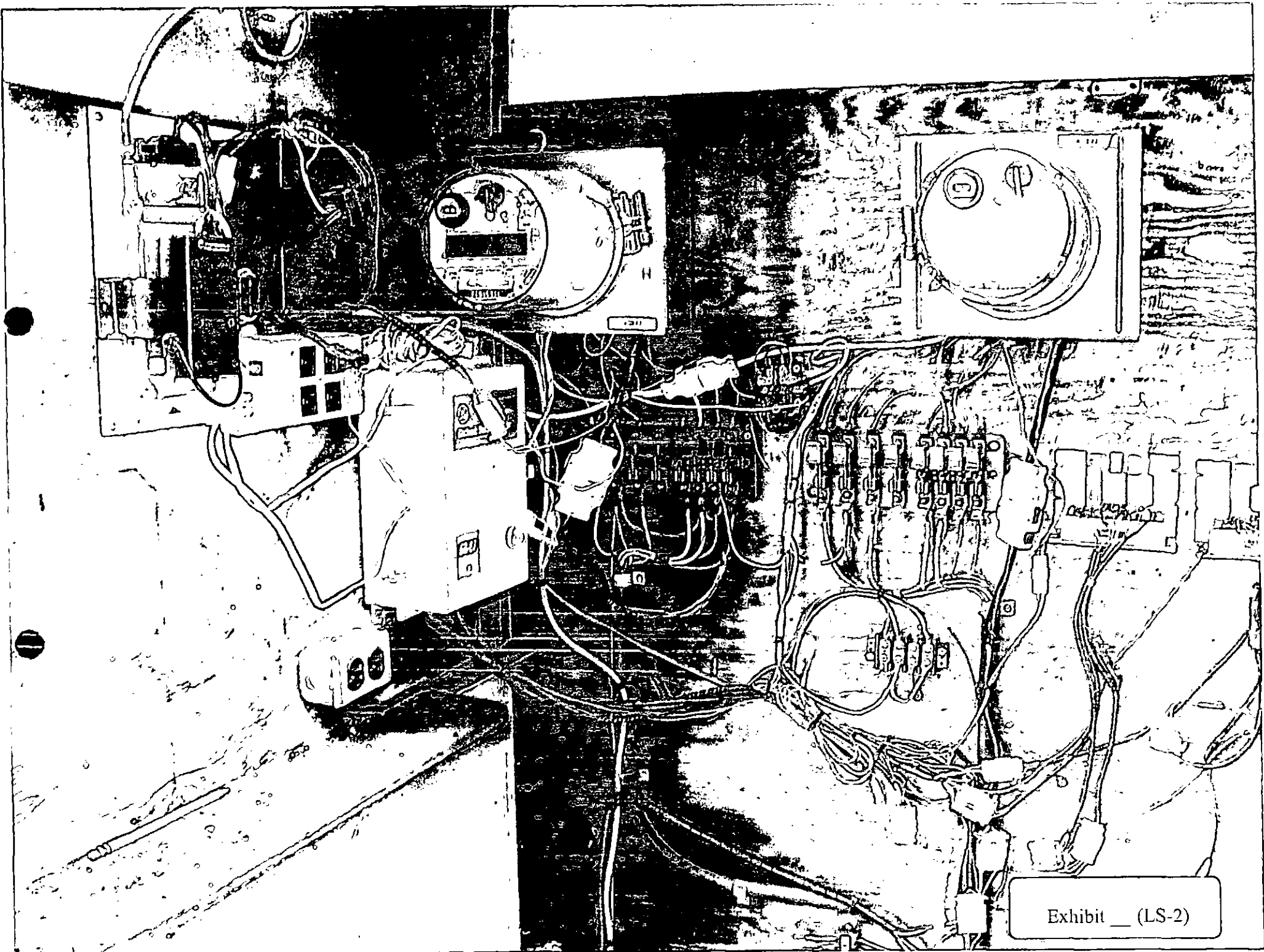


Exhibit __ (LS-2)

8-7 J-04 TRS

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DOCUMENT

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY)
COMMISSION)

v.)

) Docket No. R-00049255

PPL ELECTRIC UTILITIES)
CORPORATION)

DOCKETED

AUG 18 2004

PP&L INDUSTRIAL CUSTOMER)
ALLIANCE)

v.)

) Docket No. R-00049255C0002

PPL ELECTRIC UTILITIES)
CORPORATION)

Includes Exhibits

JHR1

through

JHR4

DIRECT TESTIMONY
AND EXHIBITS
OF
JAMES H. ROONEY

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

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2004 AUG 17 AM 9:49

**TESTIMONY BY JAMES H. ROONEY
ARMSTRONG WORLD INDUSTRIES, INC.**

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

2 A. My name is James H. Rooney. My business address is 2500 Columbia Avenue,
3 Lancaster, PA 17603.

4
5 **Q. By what company are you employed?**

6 A. I am employed by Armstrong World Industries, Inc. ("Armstrong").

7
8 **Q. How long have you worked for Armstrong?**

9 A. I have worked for Armstrong for over 36 years.

10
11 **Q. What is your current position with Armstrong?**

12 A. I am currently Manager of Worldwide Disposal, Utility and Energy Procurement
13 for Armstrong.

14
15 **Q. What are your duties in your current position?**

16 A. I am responsible for managing the domestic and international purchases of
17 electricity for Armstrong and its subsidiaries.

18
19 **Q. What is your educational and employment background prior to joining
20 Armstrong?**

21 A. I received my B.S. in Mechanical Engineering from the University of Delaware
22 and my M.B.A. from Lebanon Valley College. From 1996 to 1999, I was

1 President of the Industrial Energy Consumers of Pennsylvania, an association of
2 energy-intensive industrial customers of electricity and natural gas. IECPA was
3 one of the stakeholders that helped draft and then supported legislation that
4 became the "Electricity Generation Customer Choice and Competition Act." I
5 was President of IECPA during the implementation of the Competition Act.
6 Before I began in my current position, I held various assignments in the
7 Engineering Department, Manufacturing Organization and Purchasing
8 Department at Armstrong.

9
10 **Q. Please describe the type of business in which Armstrong is involved.**

11 A. Armstrong is a global leader in the design and manufacture of flooring and ceiling
12 products. Armstrong was founded in 1860 and is based in Lancaster,
13 Pennsylvania.

14
15 **Q. What facilities does Armstrong have in the service territory of PPL Electric
16 Utilities Corporation ("PPL")?**

17 A. Armstrong has three primary facilities that purchase electricity in PPL's service
18 territory: the Lancaster, Marietta, and Innovation Center facilities. In total,
19 approximately 2,500 people are employed by Armstrong at these three facilities.
20 The Lancaster plant manufactures resilient flooring material, the Marietta plant
21 manufactures acoustical ceiling material, and the Innovation Center has research
22 facilities, training facilities and corporate offices. The combined 2003 electric

1 consumption at all of these facilities was approximately 150,000,000 kWh.

2 Currently, we buy all of our electricity from PPL at these facilities.

3

4 **Q. On what rate schedules do these facilities purchase service from PPL?**

5 A. The Lancaster and Marietta plants receive service under Rate Schedule IS-T
6 (Interruptible Large Transmission Service at 69,000 volts or higher). The
7 Innovation Center receives service under Rate Schedule IS-P (Interruptible Large
8 General Service at 12,740 volts or higher).

9

10 **Q. What issues will you address in your testimony?**

11 A. I will address two issues. First, I will address how the proposed distribution rates
12 for the Armstrong accounts exceed PPL's calculations of the cost to serve
13 Armstrong. PPLICA witness Stephen Baron provides the underlying support for
14 this analysis. Second, I will discuss how the proposed calculation and design of
15 PPL's proposed transmission charges result in Armstrong paying to PPL more
16 than Armstrong's appropriate share of transmission and ancillary service charges.

17

18 **PPL's Proposed Distribution Rates Exceed Cost of Service.**

19 **Q. What facilities does PPL have in place to serve Armstrong?**

20 A. For Marietta and Lancaster, Armstrong's IS-T accounts, PPL has very little
21 equipment in place to serve our facilities. Armstrong owns all of the
22 transformation equipment for those accounts to convert transmission voltage
23 electricity to the lower voltage electricity used by our plants. PPL only owns the

1 meter and associated equipment plus the short line connecting our transformation
2 equipment to the transmission system. I have attached to this testimony as
3 PPLICA Exhibits ___ (JHR-1) and (JHR-2) two photographs depicting these
4 facilities.

5
6 Photograph JHR-1 shows the transformation equipment owned, operated and
7 maintained by Armstrong. That Armstrong-owned equipment in general includes
8 disconnects attached to the PPL transmission line, transformers to reduce the
9 voltage from the 69 KV transmission voltage, and wire owned by Armstrong to
10 connect and distribute the electricity to Armstrong and facilities. The meter is
11 owned by PPL. The meter is the small pink box in JHR-1 and is shown in JHR-2.

12
13 For our IS-P account, PPL owns and uses some distribution voltage (12,470 V)
14 facilities to reduce from transmission voltage to the 12,470 volts supplied to
15 Armstrong. Again, Armstrong owns equipment and wires to reduce the 12,470
16 volts to a lower voltage and distribute the electricity to the buildings and
17 operations at our Innovation Center.

18
19 **Q. What do you understand to be the cost of PPL's facilities that are used to**
20 **serve Armstrong?**

21 **A.** I understand there are installed costs associated with providing distribution
22 services and also operating and maintenance costs and taxes. I also understand
23 there are several allocators that are assigned based on overall PPL costs. In

1 particular, I want to talk about the installed costs for the IS-T service that is
2 provided to our Lancaster and Marietta plants. There are 33 IS-T customers, and
3 PPL claims that there are \$716,000 of total rate base to serve these 33 customers.
4 Since all meters for these customers are approximately the same, I divided the
5 \$716,000 by 33 and calculated metering rate base is worth about \$21,700 per
6 customer. If PPL obtains their requested 8.8% return on investment for the
7 \$21,700 investment, that yields a return of \$1,900 per year for each IS-T account.
8

9 **Q. Under PPL's cost of service study, what do you understand to be PPL's**
10 **allocated cost to provide distribution service to Armstrong's IS-T accounts?**

11 A. Based on Mr. Baron's calculations, extracted from PPL exhibits, discovery, and
12 data, revenues received by PPL to cover actual cost of service to Armstrong's IS-
13 T accounts at Lancaster and Marietta is \$62,598 per year combined for these two
14 accounts using 2003 consumption data. As a businessman, this \$62,598 that
15 Armstrong would pay to PPL for cost of service based rates still seems far above
16 the true cost to serve Armstrong, particularly considering that the return on rate
17 base assigned to Rate Schedule IS-T is only \$3,800 for the two Armstrong meters.
18 Mr. Baron's cost-based rate calculations are set forth in PPLICA Exhibit ____
19 (SJB-7).
20

21 **Q. Do you propose that Armstrong should only be paying \$3,800 for**
22 **distribution service to those two accounts?**

1 A. No, my logic is one based only on my engineering and MBA education and
2 business background. I do not propose to understand the intricacies or history of
3 the regulatory process. However, because of my calculations, I am convinced that
4 the cost of service calculations by Mr. Baron based on the information provided
5 by PPL are more than an adequate payment by Armstrong for the services
6 provided by PPL. To pay any more than this \$62,598 cost of service calculated
7 by Mr. Baron would clearly be excessive and unfair to Armstrong. For this
8 reason, Armstrong believes it is important for this Commission to adopt Mr.
9 *Baron's gradual three year movement to cost of service.*

10
11 **Q. Have you calculated what Armstrong would pay PPL each year if PPL's**
12 **proposed distribution rates were approved?**

13 A. Yes. Each year, Armstrong would pay PPL approximately \$130,640 to serve the
14 two IS-T facilities mentioned above. This is approximately two times what PPL
15 calculates the cost of service to be. This represents a combined overpayment of
16 \$67,000 annually at these facilities based on Mr. Baron's calculations.

17
18 **Q. In your opinion, is it proper for Armstrong to pay PPL \$67,000 more than**
19 **PPL's estimated cost to serve Armstrong?**

20 A. No. In essence, PPL proposes to burden Armstrong with far more than PPL's
21 actual cost to serve Armstrong, thereby subsidizing PPL's costs to serve other
22 customers. This is inequitable and wrong.

23

1 **Q. Please describe the current business environment in your business.**

2 A. In order to be competitive in a worldwide market, industry in general, and
3 Armstrong specifically, must eliminate all unnecessary costs. Given that I even
4 believe that PPL's own cost of service based rates to Armstrong are too high
5 based on the level of rate base investment, I urge the Commission not to
6 accentuate the problem further by imposing costs on Armstrong above the cost of
7 service.

8
9 **Q. What should the Commission do to help Armstrong?**

10 A. We are currently overpaying distribution charges to PPL for Lancaster, Marietta
11 and Innovation Center accounts. While PPL proposes to reduce these charges, we
12 will still be significantly overpaying the true cost of service for these facilities.
13 The Commission must eliminate this unnecessary overpayment. We are not
14 asking PPL or the Commission to make our facilities competitive, but we are
15 asking PPL and the Commission not to overcharge our facilities for services PPL
16 provides to us. In 2003, Armstrong spent \$55 million on cost-reduction initiatives
17 throughout Armstrong. Unless the Commission rejects PPL's proposals, some of
18 these successful cost reduction efforts will be offset through excessive payments
19 for the services PPL provides to us.

20
21 **Q. What action would you like the Commission to take?**

22 A. I would like the Commission to require PPL to decrease Armstrong rates to cost-
23 of-service rates as calculated and suggested by PPLICA witness, Mr. Baron. I

1 believe now is the time to immediately reduce PPL distribution costs to their true
2 cost of service. To permit other classes a gradual transition, I accept Mr. Baron's
3 three-year phase-in. But I ask the Commission to require the phase-in as part of
4 its final order. We cannot wait any longer to get to cost of service.

5
6 China and other developing countries are not waiting to compete with U.S.
7 industry. They are taking business from United States companies, and the U.S. is
8 losing manufacturing jobs to these countries. To pay PPL a premium above cost
9 of service for the monopolistic distribution services adds unnecessary costs to all
10 industry as we attempt to be competitive.

11
12 **Q. Do you have other examples to support reducing IS-T rates to cost of**
13 **service?**

14 A. Yes, attached Exhibit ___(JHR-3) shows actual metering costs in the United
15 Kingdom. There are three examples of metering costs in this exhibit. Two are
16 actually the costs for Armstrong plants, and one is a quote from our metering
17 provider for 66 KV service similar to the 69 KV IS-T service at Marietta and
18 Lancaster. This 66 KV quote includes maintenance charges, communication
19 charges, and the necessary back office support to provide the metering data to our
20 U.K. energy supplier, transmission provider, and to Armstrong. A picture of this
21 metering equipment is shown in Exhibit __ (JHR-4). The cost of this service is
22 £884 (BP) per year, which equates to approximately \$1,600 per year per meter.
23 For Lancaster and Marietta, that would mean \$3,200 per year for metering at

1 these two sites. This \$3,200 compares reasonably to the \$3,800 return
2 component that Armstrong would pay PPL that I calculated above, and both are
3 miniscule when compared to the \$130,640 per year requested by PPL for
4 Lancaster and Marietta distribution services. In essence, PPL proposes to collect
5 40 times the revenue provided by Armstrong to a similar meter service provider in
6 the U.K. Even rates based on PPL's cost of service are more than 20 times greater
7 than the rates charged for metering service in the U.K. We must stop overpaying
8 for IS-T distribution services that are in essence primarily metering services for
9 IS-T customers. We cannot let this type of premium be charged to industrials.
10 PPL must stop hurting our competitiveness in our markets by having Armstrong
11 underwrite the cost of providing distribution services to other classes of
12 customers.

13
14 **Q. How do the distribution charges of PPL cause Armstrong and other**
15 **industrials to underwrite the cost of distribution services to other customers?**

16 **A.** If PPL would charge Armstrong and other industrial customers the cost of service
17 calculated and shown by Mr. Baron, then one of two things might happen. First,
18 PPL would not obtain the rate of return they request; or second, those costs would
19 have to be borne by other customers. Primarily, the underpayment of distribution
20 services is now within the residential rate class. That would mean that residential
21 rates would have to go up if PPL is to achieve their requested rate of return. Mr.
22 Baron's suggested three-year phase-in permits residential customers a transition,
23 and I believe residential customers should fully pay for their cost of service. I

1 propose it is more logical and beneficial to charge residential customers the
2 correct cost of service and keep industrial companies such as Armstrong as
3 competitive as possible in Pennsylvania. From 1994 to 2000, Pennsylvania lost
4 over 100,000 manufacturing jobs. While cost of service distribution rate, will not,
5 of themselves, stop job loss, PPL must not be allowed to continue to penalize
6 industry with higher than justified charges.

7
8 **PPL's Proposed Transmission Service Charge Penalizes Large POLR**
9 **Customers.**

10 **Q. What is the impact of PPL's proposed increase to its transmission charges for**
11 **Armstrong's accounts?**

12 A. Currently, Armstrong pays about \$500,000 for transmission charges at Lancaster,
13 Marietta and the Innovation Center. If PPL receives their transmission billing
14 methodology and proposed rates, Armstrong's cost would go up over \$300,000, to
15 over \$800,000/year, almost a 60% increase over the current rates.

16
17 **Q. Do you have any comments regarding this increase?**

18 A. Yes. I understand that the FERC has approved new charges that PPL may be
19 legally entitled to charge retail ratepayers that purchase POLR (Provider of Last
20 Resort) services from PPL. But FERC did not specify the methodology of
21 flowing these costs to retail ratepayers. PPL has chosen to accomplish this flow-
22 through of transmission costs on a uniform cents per kWh basis. This will
23 recover more of the transmission and ancillary service costs from large customers

1 such as Armstrong and again penalizes large customers. It does not seem
2 appropriate for the rate Armstrong pays to accomplish this "flow-through" of PJM
3 charges to exceed the rate that PPL would pay to PJM to purchase the same
4 transmission services. The per KW based transmission charge proposed by Mr.
5 Baron accurately reflects the rate concept used by PJM and other transmission
6 service providers. The per KW charge reflects the cost of the wires and
7 equipment needed for the peak load of the customers just as the demand charge
8 for natural gas transmission service reflects the pipeline cost. It is not the quantity
9 of kilowatt hours that you use that should govern transmission cost but it is when
10 you use the maximum quantity of electricity that affects the cost to provide
11 transmission service.

12
13 **Q. Would a KW-based transmission charge, as proposed by Mr. Baron, provide**
14 **any other benefits to Armstrong?**

15 **A.** Yes. A per KW transmission charge provides an incentive for Armstrong to
16 control our demand during on-peak hours improving our load factor to help
17 increase transmission capacity at peak time. This benefits Armstrong (through
18 lower costs), provide lower costs to the transmission owner by minimizing their
19 investment and provides a benefit to the entire electric grid by giving Armstrong
20 and other large users an incentive to minimize our usage during peak demand
21 periods. A flat kWh transmission charge as proposed by PPL does not provide
22 the same incentive to avoid using electricity at peak demand time. PPL's per kWh
23 proposed transmission charge also will not provide a demand-side response signal

1 to participate in demand-side response programs offered by PJM and endorsed by
2 FERC.

3

4 **Q. What should Armstrong pay for transmission service?**

5 **A.** Mr. Baron's testimony shows the appropriate transmission pricing and rate design.
6 Under his proposal, the customers on Rate Schedule IS-T on which Armstrong
7 has two accounts would annually pay \$7,456,349 for transmission service instead
8 of \$11,127,614 as PPL proposes, and, Armstrong and other industrials would
9 have a better incentive to reduce their costs by reducing demand.

10

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

12 **A.** Yes.

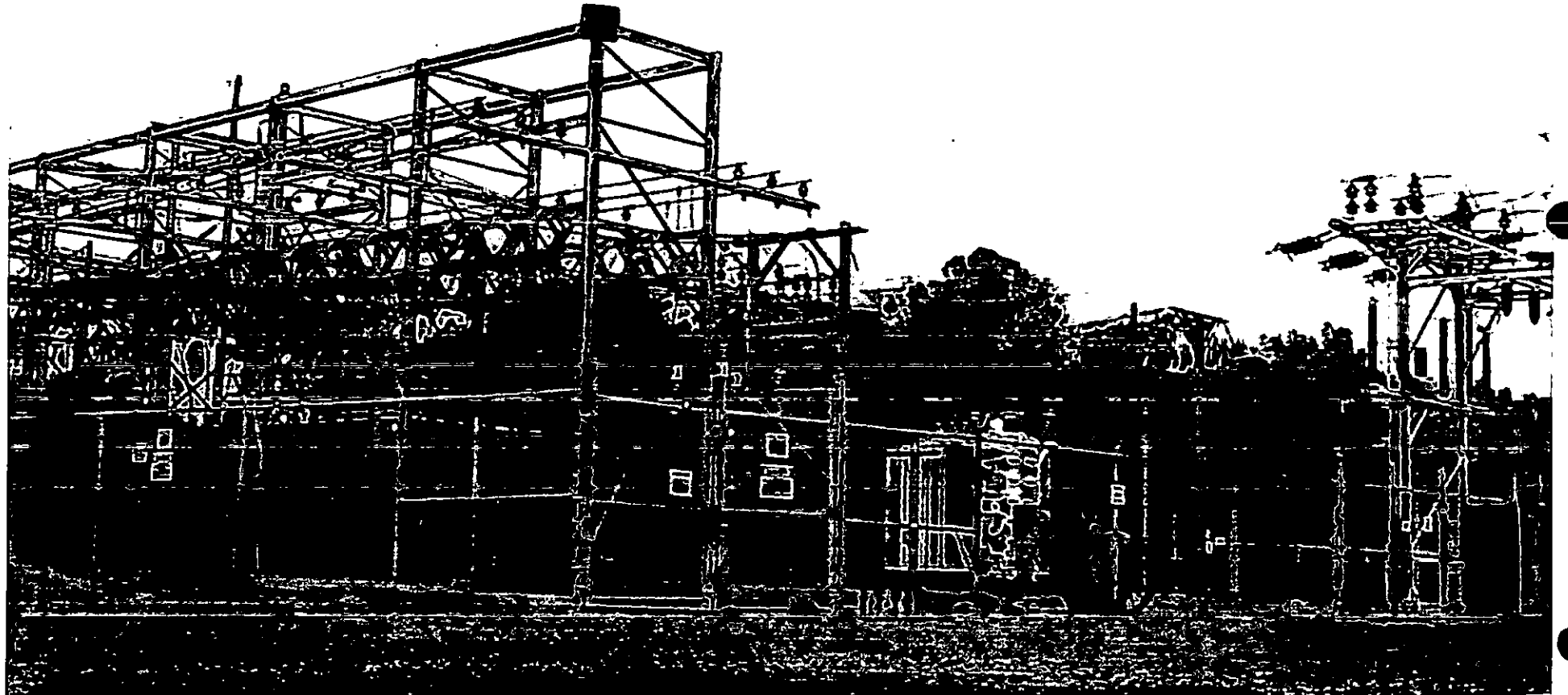


Exhibit __ (JHR-1)

Exhibit (JHR-2)



JHR-3
UK Metering Costs

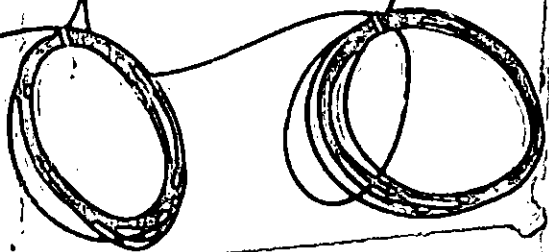
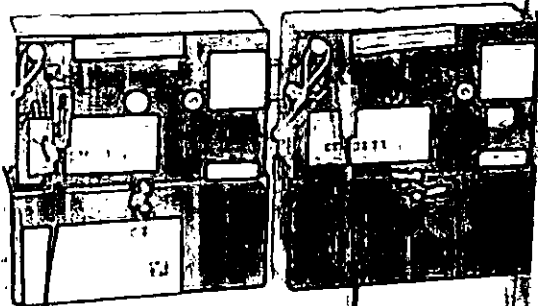
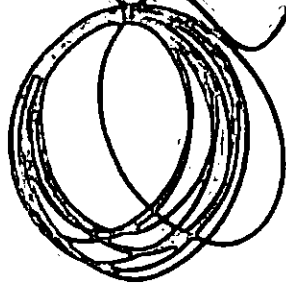
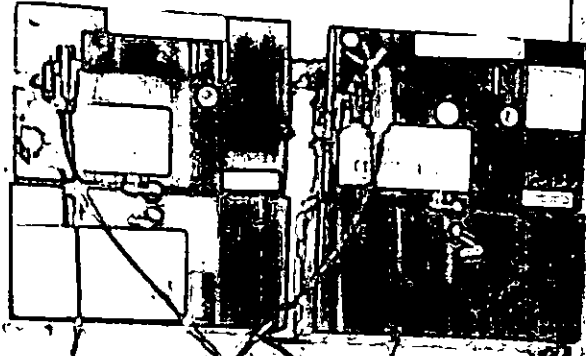
Armstrong 1		11,000 voltage service code 3 meter				
meter lease option	# of meters	charge/meter	meter charge	telecommunications charge	VAT (17.5%)	Total annual meter charges
	1	£241.00	£241.00	£200.00	£77.18	£518.18
meter purchase option	Cost to purchase code 3 meters*		£750.00			
	Annual telecommunication charges		£200.00			
	Annual operational charges		£120.00			
	Additional costs of items to be provided by customer		0			

IST Distribution Rate Combined Lancaster and Marletta	
PPL Requested	\$130,000/yr
Cost of Service/PPL	\$62,598/yr
2 Meters in UK	\$3,200/yr

Armstrong 2		22,000 voltage service code 3 meter				
meter lease option	# of meters	charge/meter	meter charge	telecommunications charge	VAT (17.5%)	Total annual meter charges
	2	£500.00	£1,000.00	£252.00	£219.10	£1,471.10
meter purchase option	Cost to purchase code 3 meters*		£1,500.00			
	Annual telecommunication charges		£200.00			
	Annual operational charges		£120.00			
	Additional costs of items to be provided by customer		0			

Quoted		66,000 voltage service cost code 2 meter						
meter lease option	# of meters	charge/meter	meter charge	telecommunications charge	VAT (17.5%)	Total annual meter charges	Conversion Rate to US\$	Total annual meter charges
	1	£500.00	£500.00	£252.00	£131.60	£883.60	1.8	\$1,590.48
meter purchase option	Cost to purchase code 2 meter*		£1,000.00					
	Annual telecommunication charges		£200.00					
	Annual operational charges		£250.00					
	Additional costs of items to be provided by customer		minimal					
			Items needed for a new metering service to be installed - MPAN# (provided by dist. Company) - new meter to be mounted on distribution panel - wires from the new service switchgear to run through the new meter			Meter charges should not vary by location within the UK or by the supply voltage but do vary by the customer demand or consumption 0 - 100KVA non-half hourly data 100KVA-1,000KVA code 5 meter(1 main meter), half hourly data 1,000KVA - 10,000KVA code 3 meter (1 main meter & 1 check meter) half hourly meter 10,000KVA - 100,000KVA code 2 meter (1 main meter & 1 check meter with higher specifications and accuracy), half hourly data		

*Meter has a 10 year life span after which the owner is obligated to replace the meter



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LHB 6

R 245278

DOCUMENT BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

**PENNSYLVANIA PUBLIC UTILITY)
COMMISSION)**

v.

) **Docket No. R-00049255**
)

**PPL ELECTRIC UTILITIES)
CORPORATION)**

**PP&L INDUSTRIAL CUSTOMER)
ALLIANCE)**

v.

) **Docket No. R-00049255C0002**
)

**PPL ELECTRIC UTILITIES)
CORPORATION)**

DOCKETED

AUG 18 2004

**DIRECT TESTIMONY
OF
AARON P. CROOP**

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

RECEIVED
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SECRETARY'S BUREAU

**TESTIMONY BY AARON P. CROOP
ANVIL INTERNATIONAL, INC.**

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

2 A. My name is Aaron P. Croop. My business address is 1411 Lancaster Avenue,
3 Columbia, PA 17512.

4
5 **Q. By what company are you employed?**

6 A. I am employed by Anvil International, Inc. ("Anvil"), one of the world's largest
7 manufacturer of threaded pipe fittings, pipe hangers, and supports, as well as
8 grooved-end fittings, couplings, and valves. Our products are used in various
9 industries, including plumbing, fire protection, mining, oil and gas, and water and
10 wastewater.

11

12 **Q. How long have you worked for Anvil?**

13 A. I have worked for Anvil for 10 years.

14

15 **Q. What is your current position with Anvil?**

16 A. I am currently Senior Environmental Engineer for Anvil.

17

18 **Q. What are your duties in your current position?**

19 A. It is my responsibility to ensure that the Anvil International Columbia Plant
20 complies with all applicable environmental regulations. I am also responsible for
21 promoting continuous environmental improvement at the Columbia facility,
22 including conservation and efficient use of raw materials and resources. I monitor

1 utility use (including electricity, natural gas, water, sewer, liquid nitrogen and
2 liquid oxygen), and recommend projects to reduce consumption. I also act as
3 project manager on other facilities improvement projects.
4

5 **Q. What is your educational and employment background prior to joining
6 Anvil?**

7 A. I joined Anvil after graduating college. I graduated from The Pennsylvania State
8 University with a Bachelor's Degree in Environmental Engineering Technology.
9

10 **Q. Does Anvil have a facility located in the service territory of PPL Electric
11 Utilities Corporation ("PPL")?**

12 A. Yes, Anvil International Columbia Plant is located in Columbia, Pennsylvania,
13 within the PPL service territory. The Columbia Facility is approximately 53 acres
14 in size, with approximately 690,000 square feet under roof.
15

16 **Q. On what rate schedule does Anvil purchase service from PPL?**

17 A. The plant purchases electricity from PPL on Rate Schedule LP-5 (Large General
18 Service – 69 kV or Higher).
19

20 **Q. Please provide some background information regarding the facility.**

21 A. Anvil consumes approximately 125,000,000 kWh of electricity per year, and
22 employs approximately 720 unionized workers, as well as approximately 110
23 office and management employees. This facility has been in continuous operation

1 as an iron foundry at its present location since 1929. Our facility is comprised of
2 both iron melting/molding operations, and product finishing and machining
3 operations. We use electric induction furnaces to melt scrap steel to produce
4 malleable, ductile, and gray iron castings. As stated previously, this facility
5 manufactures threaded and grooved pipe fittings, pipe hangers, supports, and
6 valves. A vast majority of these products are shipped as finished goods from the
7 Columbia Plant. Our products are marketed, distributed, and serviced nationwide
8 and overseas, and provide livelihood for thousands of families. Recently, Anvil
9 has come under severe market pressure from offshore competition from countries
10 *that do not have established working standards and environmental controls.* This
11 unfair competition threatens the future of Anvil, and the future of the metal
12 casting industry in the United States.

13
14 **Q. What issues will you address in your testimony?**

15 A. I will address two issues. First, I will address the fact that PPL's proposed
16 distribution rates for Anvil exceed PPL's allocated cost to serve Anvil. Second, I
17 will explain how PPL's proposed transmission rate increase would penalize Anvil
18 by impacting Anvil to the same extent regardless of whether Anvil takes steps to
19 minimize its on-peak usage.

20
21 **PPL's Proposed Distribution Rate for Anvil Would Exceed Anvil's Cost of**
22 **Service.**

23 **Q. What distribution facilities does PPL have in place to serve Anvil?**

1 A. Anvil takes service from PPL at 69 kV, which is transmission level voltage. We
2 own the equipment that we use to convert the electricity to voltage levels that can
3 be used at our facility. PPL owns both the meter and the short line connecting our
4 meter to PPL's transmission system. I have provided as PPLICA Exhibit _____
5 (APC-1) a line diagram showing these facilities.

6

7 The Boxes labeled "A" and "B" depict the "tap lines" that connect PPL's 69 kV
8 system to our site. As shown on the exhibit, these are owned and maintained by
9 PPL. Directly under Boxes A and B is our substation area (labeled as Box "C").
10 Anvil owns and maintains the equipment in the substation area. After the
11 electricity flows through Anvil's oil circuit breakers (OCB's), it encounters the
12 PPL-owned metering equipment in Box "D". Beyond PPL's meters, Anvil owns
13 and maintains various pieces of equipment to transform the electricity into the
14 voltages that are necessary to operate our furnaces and other manufacturing
15 equipment. These include transformers, switches, capacitors, breakers and other
16 equipment. As the diagram illustrates, the equipment owned and operated by
17 Anvil comprises the vast majority of the facilities necessary to supply electricity
18 to our manufacturing equipment. There are many more pieces of transformation
19 equipment owned by Anvil that are not shown on the diagram.

20

21 Q. **What services does PPL currently provide Anvil?**

1 A. PPL provides Anvil with two services: (1) billing; and (2) access to a
2 commercial/industrial customer hotline for the resolution of service and billing
3 issues.

4
5 **Q. Under PPL's cost of service study, what amount of PPL's costs is allocated to**
6 **servicing Anvil?**

7 A. Based upon my review of Mr. Baron's calculations, which were prepared based on
8 information provided by PPL and are set forth in PPLICA Exhibit ___ (SJB-7), if
9 PPL's distribution rate for Rate Schedule LP-5 is set based on the system average
10 rate of return, then Anvil would pay \$29,146.43 per year for distribution service .

11
12 **Q. Have you calculated what Anvil would pay PPL annually under PPL's**
13 **proposed distribution rates?**

14 A. Yes. I have determined that, if the PUC approves PPL's proposed distribution
15 rates, Anvil will pay PPL \$45,057.28 annually. This is approximately one and
16 one-half times PPL's actual cost to serve Anvil. Below, I have included a table
17 that shows the amount of Anvil's overpayment.

18

Proposed Anvil Payment	Anvil Payment at System Average Return	Overpayment
\$45,057.28	\$29,146.43	\$15,910.85

19

1 Q. Do you have any comments concerning PPL's proposal to charge Anvil
2 \$16,000 more than PPL's actual cost to serve Anvil?

3 A. Yes. It does not seem fair or reasonable to charge Anvil so much more than PPL's
4 actual cost to serve Anvil.

5

6 Q. How would you like the Commission to respond to PPL's request?

7 A. I would like the PUC to lower PPL's rates for service to Anvil to a level more
8 closely related to PPL's actual cost to serve Anvil. However, I understand that the
9 PUC may consider such a reduction to be too dramatic to be implemented at once.
10 Therefore, I would like the PUC to at least begin to gradually reduce Anvil's
11 distribution rates to a level closer to PPL's cost to serve Anvil, as recommended in
12 Mr. Baron's phase-down plan that was submitted in this proceeding as PPLICA
13 Exhibit ____ (SJB-10) and described in Mr. Baron's testimony.

14

15 **PPL's Proposed Transmission Rate Increase Would Penalize Anvil.**

16 Q. Do you have any comment regarding PPL's proposed transmission rate
17 increase?

18 A. Yes. Based on our consumption from June 2003 through May 2004 and the
19 transmission service rate level projected by PPL, I calculate that Anvil will be
20 forced to pay \$678,779.64 per year in transmission charges if we continue to
21 purchase generation supply from PPL. This is \$312,912.60 more per year than we
22 pay under our current transmission rate of \$0.00304 per kWh, or 85.5% more for
23 transmission service if the PUC approves PPL's proposal. This is a dramatic

1 increase for which Anvil had no capability of predicting or budgeting. I also
2 understand based on Mr. Baron's expert analysis of the PPL TSC that Anvil
3 would be systematically overcharged for transmission service under the PPL
4 proposal.

5
6 **Q. Does Anvil undertake efforts to minimize its usage during peak periods?**

7 A. Yes. Anvil has installed equipment that limits our electricity usage during on-
8 peak periods. Our on-peak demand is generally about 1/3 that of our off-peak
9 demand. In order to accomplish this, we tailor our regular production schedule to
10 match PPL's off-peak hours. This has consequences for our other production
11 costs because, according to our labor agreement with the union, the company is
12 required to pay hourly nightshift premiums for a majority of the hours we are in
13 production. Additionally, strict power management must be employed during on-
14 peak hours in order to slowly "melt-in" steel scrap, in preparation for the next
15 production shift, and we must avoid any other activities that would produce an
16 unexpected increase in on-peak demand. When PPL bills us for distribution
17 service, generation supply service and the transition charges, the Company uses
18 our highest on-peak fifteen minute demand as the "Billing KW" to calculate the
19 charges. Under the rate structure in the tariff and our contract, keeping our
20 Billing KW as low as possible results in lower electricity costs.

21
22 Under our contract, we also have the opportunity to use the "Demand Free Days"
23 option in Rate Schedule LP-5. This allows us to annually pre-select three

1 workdays a week (from Tuesday through Friday) during which our on-peak
2 demands will not be used in the determination of the monthly Billing KW. PPL
3 has the opportunity to cancel the Demand Free Day by providing us with notice
4 by 2:00 P.M. on the day before. Demand Free Days are canceled when demand
5 on the power grid is high and/or generation is low. When PPL cancels a Demand
6 Free Day, Anvil cancels or modifies production shifts on that day to ensure our
7 electric load remains low during the on-peak hours.

8
9 **Q. Does PPL's proposed transmission rate design recognize Anvil's demand**
10 **control activities?**

11 A. No. We will be charged the same rate as all other customers regardless of when
12 we use the electricity or whether Anvil took steps to minimize its usage during
13 on-peak periods. As PPLICA's expert witness Mr. Baron testifies, although the
14 current transmission charge is also assessed on a kWh basis, the allocation of the
15 transmission costs to the various rate schedules was at least accomplished on a
16 kW basis, which would provide some recognition of the demand control activities
17 of any customers within that rate schedule.

18
19 **Q. Would Mr. Baron's proposed per-kW Transmission Service Charge ("TSC")**
20 **provide an incentive for Anvil to continue demand controls?**

21 A. Yes.

1 **Q. Have you calculated whether Mr. Baron's alternate TSC will reduce Anvil's**
2 **transmission costs if the facility continues to purchase generation supply**
3 **from PPL?**

4 A. Yes. I asked PPL to provide me with Anvil's Peak Load Responsibility for
5 Transmission, which is the billing determinant that Mr. Baron proposes to use for
6 the demand portion of the TSC. Using this and my June 2003 – May 2004
7 consumption, I calculate that our annual transmission payments under Mr. Baron's
8 alternate TSC would be \$666,260.37. This is a reduction of \$12,519.27 in
9 comparison to Anvil's projected charges under the proposed PPL TSC.

10

11 **Q. Do you have any other comments concerning Mr. Baron's TSC proposal?**

12 A. Yes. It is my understanding that the TSC proposed by Mr. Baron would be
13 calculated under the same methodology that a competitive supplier would use to
14 determine transmission and ancillary service charges for Anvil. For this reason, I
15 think the proposed TSC would encourage competition by making it easier to
16 compare PPL's POLR rates with competitive supply offers.

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

18 A. Yes.

872 WJES
 GABL
 Rev 1958

OVER SIZED DOCUMENTS

POWER TRANSFORMER
 NIAGARA
 TRANSFORMER
 S/N 54601

1750 KVA
 1 ϕ , 60HZ
 67KV PRI./
 12KV SEC.
 MINERAL OIL
 = 1174
 GAL., Z=
 7.0@ 85' C

NIAGARA TRANS
 1750 KVA, 1 ϕ
 12 KV-600V S/N 54625

REF. DWG. NO.,
 D-1-10901
 SH. 4
 FOR CABLE
 SIZES

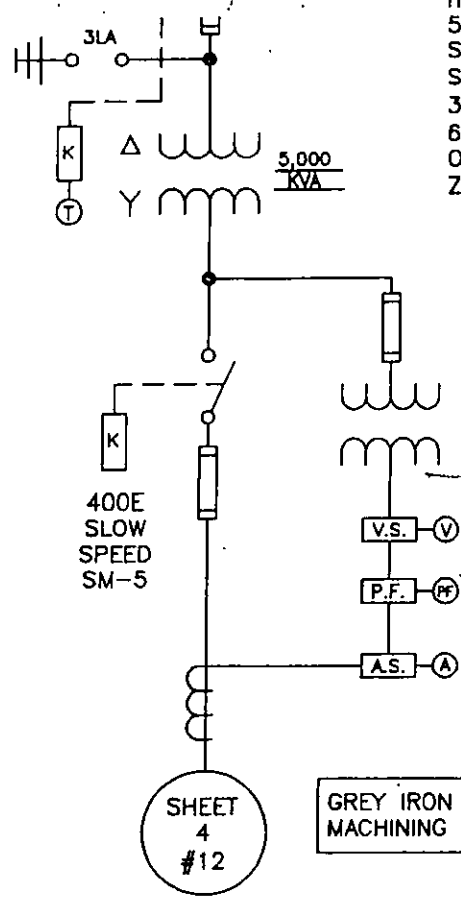
DOA FUSING

URNACE No. 1

INDING
 KW COIL

400E STD. SPEED

69 KV AUX SUB.
 G.E. POWER TRANSFORMER
 5000 KVA - ϕ 55 DEG. C
 SELF-COOLED
 S/N 16693
 3 ϕ , 60 HZ, OA/FA
 69KV. PRI. / 12.47KVSEC.
 OIL= 1850 GAL
 Z = 7.36%



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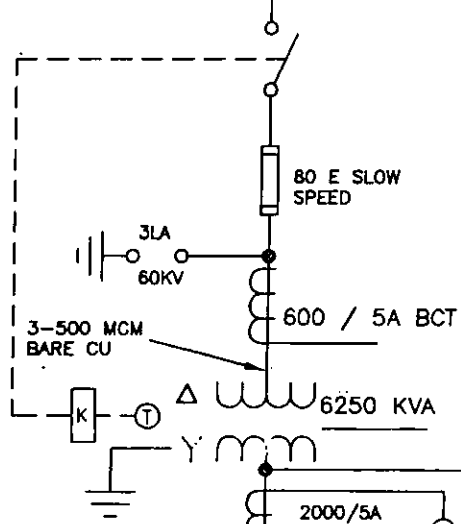
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12,470 VOLT BUSS
 F.L.C. - 232 A @ 5 MVA
 REF. DWG. NO. E-11-28195

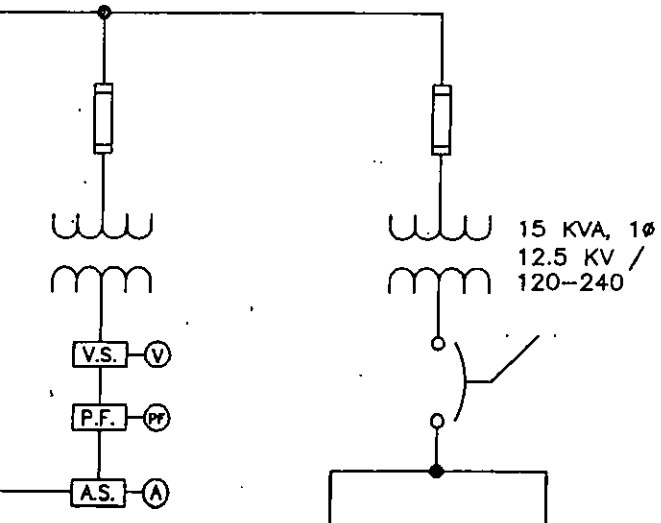
STD. SPEED

69 KV MAIN SUB.
 G.E. POWER TRANSFORMER
 10 MVA - ϕ 55 DEG. C
 SELF-COOLED
 S/N M-161545 A
 EQ. NO. 84-
 3 ϕ , 60 HZ, OA/FA
 69KV. PRI. Δ / 12.47KVSEC. Y
 OIL= 1940 GAL
 Z = 7.36%

5,000 KVA

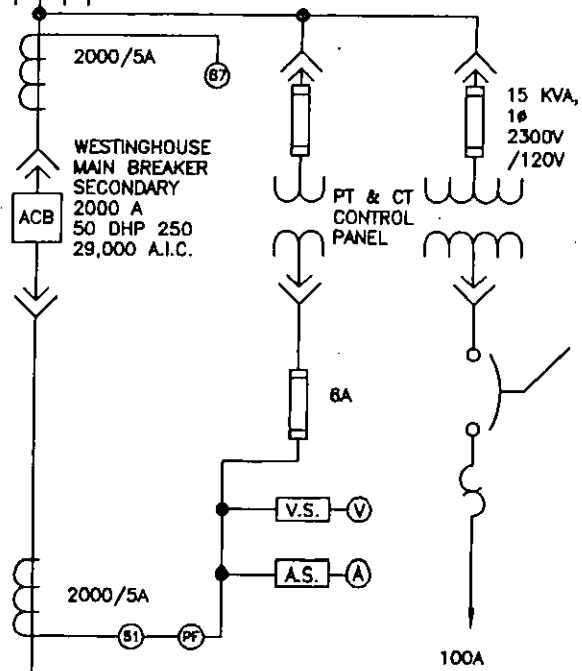


MAIN
 WESTINGHOUSE (1971)
 POWER TRANSFORMER
 S/N PJP17161 5000/6250 KVA
 - 55'C
 EQ. NO. 84-4262
 3 ϕ , 60 HZ, OA/FA
 69KV. PRI. / 2400 SEC.
 OIL = 1780 GAL. Z=7.3% Y
 5000 KVA



S. TAP SUB
 N. C/F SUB
 S. C/F SUB
 CFX SUB

SUBSTATION
 DISTRIBUTION



No. 12 XLE COMP.
 W. CENTAC AIR COMP
 E. CENTAC AIR COMP
 No. 4 BAC

WESTINGHOUSE
 SWITCHGEAR
 FANS,
 CONTROL

BTD-04 JES
WAB

DOCUMENT BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

w/RAG1 - RAG 4

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
v.)
PPL ELECTRIC UTILITIES)
CORPORATION)

DOCKET NO. R-00049255

DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

DOCKETED

AUG 18 2004

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 2004

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EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)	
UTILITY COMMISSION)	
)	
v.)	DOCKET NO. R-00049255
)	
PPL ELECTRIC UTILITIES)	
CORPORATION)	

DIRECT TESTIMONY OF RICHARD A. GALLIGAN

I. Introduction

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A. My name is Richard A. Galligan. I am a Principal with Exeter Associates, Inc., a firm of
3 consulting economists specializing in utility economics. My business address is 5565
4 Sterrett Place, Suite 310, Columbia, Maryland 21044.

5 Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

6 A. I have two degrees from the University of Wisconsin, including a Master's degree in
7 economics and, in addition, I completed two years of graduate study at the University of
8 Minnesota, where I fulfilled all of the course work requirements for the Ph.D. degree.

9 Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

10 A. I have taught economics at the University of Minnesota, the University of Wisconsin,
11 Mankato State University, and Webster College. In these positions, I taught a wide range
12 of courses covering all aspects of economics.

13 In January 1975, I joined the staff of the Minnesota Public Service Commission at
14 the commencement of that Commission's responsibility over gas and electric utility

1 operations in the State of Minnesota. From 1976 to 1984, I was an economic consultant
2 specializing in public utility rate regulation of gas, electric and telephone utilities.

3 From 1984 until 1987, I was Director of Utilities Division at the Iowa State
4 Commerce Commission and Executive Director of the Texas Public Utility Commission.
5 At Iowa, my responsibilities included the management and administration of all Utilities
6 Division activities regarding the regulation of gas, electric and telephone utilities
7 operating in the State of Iowa under Iowa State Commerce Commission jurisdiction. At
8 the Texas Public Utility Commission, I was responsible for the management and day-to-
9 day administration of that Commission's regulatory activities regarding all aspects of its
10 jurisdictional responsibilities. I also served briefly as General Manager of Rates &
11 Regulatory Affairs at Gas Company of New Mexico before assuming my present position
12 at Exeter Associates, Inc. in October 1987.

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

15 A. Yes. I have previously presented testimony on more than 90 occasions before the Federal
16 Energy Regulatory Commission ("FERC") and the public utility commissions of
17 Alabama, California, Connecticut, Delaware, the District of Columbia, Florida, Georgia,
18 Idaho, Illinois, Kansas, Louisiana, Maryland, Michigan, Minnesota, Missouri, Montana,
19 Nevada, New Hampshire, New Jersey, North Carolina, Ohio, Pennsylvania, Rhode
20 Island, South Carolina, South Dakota, Tennessee, Texas, Utah, and Vermont.

21 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

22 A. Exeter Associates, Inc. was retained by the Pennsylvania Office of Consumer Advocate
23 ("OCA") to review the class cost of service studies, proposed revenue allocation and rate
24 design proposals for the residential class reflected in PPL Electric Utilities Corporation's
25 ("PPL's" or "the Company's") current application for a general rate increase. My

1 testimony addresses the allocation of certain distribution costs in the cost of service
2 study, the revenue allocation, and rate design issues applicable to the Residential class.

3 Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR
4 TESTIMONY?

5 A. Yes. I have prepared Schedules RAG-1 through RAG-4, which are attached to my
6 testimony.

7 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

8 A. Following this introductory section, my testimony is divided into three additional
9 sections. The first additional section begins with a brief summary overview of the
10 distribution cost allocation philosophy reflected in the class cost of service studies
11 submitted on behalf of PPL. Following the overview, I detail the reasons that support a
12 finding that the Company's proposed allocation of distribution costs produces an
13 unreliable indication of the costs of serving the various customer classes.

14 The second additional section presents my recommendation regarding the
15 allocation among the various customer classes of any revenue increase authorized in this
16 proceeding. The third additional section is a discussion of the Company's Residential
17 rate design proposals and my evaluation and recommendations with respect to PPL's
18 proposals.

19 Q. WHAT CONCLUSIONS HAVE YOU REACHED AS A RESULT OF YOUR
20 REVIEW AND ANALYSIS?

21 A. I have reached the following conclusions:

- 22 • PPL's allocation of Common Distribution, or integrated plant and related expenses,
23 is at odds with the principle of cost causality, and produces unrealistic indications of
24 calculated class rates of return;

- 1 • PPL's "customer" component of its secondary Common Distribution, or integrated
2 plant facilities, actually includes costs related to the provision of capacity service as
3 well as the provision of "customer" service, thus overstating its claimed "customer"
4 costs;
- 5 • PPL further errs in the performance of its cost of service studies by failing to
6 recognize the capacity component of service that can be provided from its
7 "customer" cost of service when it allocates capacity related Common Distribution
8 costs on the basis of customer demands;
- 9 • The allocation of Common Distribution plant investment, partially on the basis of
10 average demands and partially on the basis of peak demands eliminates the
11 misallocations in PPL's studies by reflecting the load carrying capabilities of the
12 distribution system, and is consistent with the principle of cost causality;
- 13 • PPL's proposed revenue spread is reasonable;
- 14 • The requested authority to increase the Residential RS Distribution Charge from
15 \$6.55 to \$12.20 and to eliminate any price for first-block consumption should be
16 denied;
- 17 • PPL should retain its present Residential RS rate design consisting of a Distribution
18 Charge and a three-block usage rate structure; and
- 19 • The requested authority to increase the Residential RTS Distribution Charge from
20 \$15.21 to \$20.20 and to reduce the kW charge from 90-cents per kW to 56-cents per
21 kW should be denied.

22

1 **II. Allocation of Distribution Costs in the Cost of Service Study**

2 Q. PLEASE DESCRIBE THE ATTRIBUTES OF A CLASS COST OF SERVICE
3 STUDY.

4 A. Average, embedded, historic class cost of service studies of the type performed by PPL
5 and included in exhibits JMK-1 and 2 are an attempt to determine the share of total costs
6 that is incurred to provide service to each class of customers. The studies are called
7 average, embedded, historic cost studies because they attempt to directly assign or
8 allocate actual book plant and related costs, adjusted to test year levels as authorized by
9 the Commission, to each customer class. The costs are first functionalized into broad
10 cost categories such as Distribution costs, often by voltage level, or Customer costs.
11 Costs are then classified as to whether the costs are demand related, energy related,
12 customer related or related to revenues. Finally, the costs are allocated to the customer
13 classes on the basis of various measures of demand, customers, etc., in proportion to each
14 class' contribution to the various allocation measures.

15 Q. PLEASE DESCRIBE THE VARIOUS TYPES OF DISTRIBUTION PLANT
16 INVESTMENT THAT ARE INCLUDED IN THE COMPANY'S TOTAL COST
17 OF SERVICE IN THIS PROCEEDING AND ARE SUBJECT TO
18 ALLOCATION IN THE COMPANY'S COST STUDIES.

19 A. PPL's Distribution plant can be typified in a number of ways. One useful way to
20 understand the allocation issues regarding PPL's distribution plant is to divide
21 distribution plant into three categories: One, "Primary Distribution" plant, which
22 includes PPL's distribution substations and primary overhead and underground lines.
23 Two, "Common Distribution" plant, which consists of the lower, secondary portion of
24 PPL's distribution plant, including secondary overhead and underground lines, poles, and
25 line transformers. Common Distribution Plant is system plant, since it generally serves

1 more than one customer and is built and must be sized to provide for various demands
2 that may be placed on the plant components. Three, "Services and Meters" plant.

3 Services and Meters plant consists of exactly those two components and is that portion of
4 PPL's plant which is located closest to its customers, providing the delivery of electricity
5 to individual customers.

6 *The Primary Distribution plant delivers electricity from the Transmission system*
7 *to the secondary system, stepping the voltages down from 69 kV, 23 kV and 12 kV and*
8 *ultimately to secondary voltage levels. The Common Distribution plant distributes*
9 *electricity throughout PPL's service area by delivering electricity from the primary*
10 *system to customer Services while completing the transformation of voltages down to*
11 *delivery level voltages. Generally, Services complete the delivery of electricity from the*
12 *output side of line transformers to the Meter located on or near structures on the*
13 *customers' premises. Services and Meters plant is generally associated with the*
14 *provision of service to individual customers. As mentioned above, Common Distribution*
15 *plant, including overhead and underground lines, poles and line transformers performs a*
16 *system function, being plant that is generally used by multiple customers. Primary*
17 *Distribution plant, too, including substations and primary lines performs a system*
18 *function and is generally used by multiple customers. Just as with Common Distribution*
19 *Plant, Primary Distribution plant must be sized to provide for the maximum coincident*
20 *loads that the plant may be required to serve.*

21 Q. PLEASE DESCRIBE THE BASIS UPON WHICH PPL ALLOCATED ITS
22 PRIMARY PLANT, ITS COMMON DISTRIBUTION PLANT AND ITS
23 SERVICES AND METERS PLANT.

24 A. Generally, each of the three categories of distribution plant were allocated by PPL on one
25 of three different allocation bases. Generally, Services and Meters plant was allocated by

1 PPL to classes on a customer count basis. Common Distribution plant, including lines,
2 poles and line transformers, was allocated on a separate customer/demand basis applied
3 to the various plant items included in the Common Distribution plant category, which
4 resulted in an overall 60 percent customer component and a 40 percent demand
5 component when applied to all allocated lines, poles and line transformers. The Primary
6 Distribution plant was allocated to classes solely on the basis of class noncoincident
7 demands, regardless of when during the year the class peak is established.

8 I have not challenged PPL's allocations of either its Primary Distribution plant or
9 its Services and Meters plant. I do believe PPL's reliance on a customer component
10 based on the "minimum system" concept to allocate its Common Distribution, or system
11 integrated plant, produces unreliable indications of the cost of providing service to its
12 several customer classes. Immediately below I discuss the misallocations inherent in
13 PPL's allocation of its Common Distribution plant. Later in my testimony I present the
14 results of an alternative allocation of PPL's Common Distribution plant that both
15 eliminates the errors incorporated into PPL's studies and better comports with the
16 principle of allocating costs on the basis of cost causality.

17
18 **The Misallocation of PPL's Common Distribution, or System Integrated, Plant Inherent in**
19 **PPL's Cost Studies**

20 Q. IN ITS HISTORIC AND FUTURE TEST YEAR STUDY VARIANTS WHICH
21 CLASSIFY A PORTION OF ITS COMMON DISTRIBUTION PLANT AS
22 CUSTOMER-RELATED, HOW DID PPL DETERMINE THE AMOUNT OF
23 COMMON DISTRIBUTION PLANT INVESTMENT TO CLASSIFY AS
24 CUSTOMER-RELATED?

1 A. The Company determined its customer component of Common Distribution plant based
2 on the minimum system cost concept. Under this approach, the customer component of
3 each plant account that is deemed to be partially customer and partially demand related
4 was determined by PPL based on the smallest sized plant that is capable of providing
5 service to the customers' load. PPL determined the customer related portion of its poles,
6 lines and line transformers by first determining how much of its investment installed in
7 each of these type of plants would have cost, if the total amount of each type of plant
8 were based entirely on the costs of its minimum sized equipment. PPL used the
9 minimum sized equipment it currently installs as the basis for determining the minimum
10 cost it would incur to deliver electricity to its customer loads if all its customers were
11 provided service with the minimum sized system.

12 For example, the minimum sized pole PPL currently installs is a 40-foot pole.
13 The total calculated cost of all of PPL's 876,290 actual poles of varying size would be
14 \$395,266,213 if each actual installed pole were to cost the same as PPL's average
15 embedded \$451.06 cost of its 384,216 40-foot poles. This plant investment cost that PPL
16 would have incurred if all its poles were installed at the cost of its minimum sized poles
17 compares to PPL's actual book cost of \$657,527,183 for the actual poles PPL did install.
18 The ratio of the calculated pole investment costs if all the poles were of the minimum
19 size, to the pole investment cost of PPL's actual poles installed, in this case 60.11
20 percent, is deemed to be the customer portion. The cost in excess of the 60.11 percent
21 customer portion, or 39.89% (100% - 60.11% = 39.89%), is deemed to be demand
22 related.

23 Details of PPL's determination of each of the customer components that PPL
24 contends is included in its Common Distribution plant are shown in PPL witness Kleha's
25 Exhibit JMK-3 at page 13. For each account deemed by PPL to have a customer

1 component, the customer component is based on the ratio of the investment cost PPL
2 would have incurred if all pieces of equipment in the account were of the minimum sized
3 component that PPL currently installs compared to the investment cost of PPL's actual
4 equipment installed.

5 Q. ARE THERE PROBLEMS WITH PPL'S CUSTOMER/DEMAND
6 DETERMINATIONS FOR THOSE COMMON DISTRIBUTION PLANT
7 COMPONENTS THAT PPL CONTENDS HAVE A CUSTOMER
8 COMPONENT?

9 A. Yes. The first problem is that PPL calculated its proposed customer component in a way
10 that allowed capacity, or demand related costs, to be included in the customer related cost
11 component. The second problem is that PPL allocated the demand related portion of its
12 Common Distribution plant accounts in a manner that failed to recognize that all or a
13 portion of smaller customer demands and a portion of its larger customer demands can be
14 met with the plant PPL included in its minimum sized system. Finally, a third problem
15 relates to PPL's increasing the size of its minimum sized system upon which it bases its
16 customer cost determinations.

17 In addition to these flaws in how PPL tried to quantify a customer component in
18 that portion of its plant that PPL believes has both a customer component and a demand
19 component of service, PPL has allocated no costs on average demands through the year.
20 This is ironic because the basic service that PPL provides, and the reason why PPL exists
21 and costs are incurred, is the delivery of electricity throughout the year to meet its
22 customers average demands. After discussing the measurement problems in PPL's
23 customer cost determinations, I address the misallocation of PPL's demand related costs.

1 Q. PLEASE EXPLAIN YOUR FIRST CONCERN WITH PPL'S INCLUSION OF
2 CAPACITY RELATED COSTS IN ITS CUSTOMER COMPONENT OF ITS
3 COMMON DISTRIBUTION PLANT.

4 A. Let me use line transformers as an example. PPL subscribes to the notion that line
5 transformers contain customer and capacity components of service. The determination of
6 PPL's claimed customer component of overhead line transformers serves as an example
7 of the improper inclusion of capacity related costs in a customer cost determination.
8 Because a 30 kVA transformer is the smallest transformer currently installed by PPL,
9 PPL used the costs of its 30 kVA overhead transformers as the basis of its overhead line
10 transformer customer cost determination. A 30 kVA transformer provides capacity as
11 well as being a part of PPL's customer related costs. In fact, many of PPL's customers
12 have their entire electric demands provided by 30 kVA or smaller transformers. When
13 the capacity related component inherent in PPL's 30 kVA transformers is allocated on a
14 customer count basis instead of being allocated on the demands of customers, a
15 misallocation of costs results. For example, because Residential RS customers represent
16 83 percent of PPL's customer count, Residential RS customers are allocated 83 percent of
17 the customer component of line transformers (which actually includes a capacity
18 component as well), but Residential RS customers are responsible for only 51 percent of
19 the demands placed on line transformer capacity. By including capacity costs in the
20 customer component and allocating 83 percent of the capacity costs to residential
21 customers on a customer count basis instead of 51 percent on a demand basis, capacity
22 costs are misallocated to the detriment of residential customers.

23 Q. CAN CUSTOMER COSTS BE DETERMINED IN A MANNER THAT
24 ATTEMPTS TO KEEP CAPACITY RELATED COSTS OUT OF THE
25 CUSTOMER COMPONENT?

1 A. Yes. The minimum intercept, or zero intercept method attempts to determine the
2 hypothetical no-load, or zero intercept, costs that would include no capacity related costs.
3 *The zero intercept method confirms the impropriety of including capacity costs in*
4 *customer cost determinations. I do not advocate the use of zero intercept method because*
5 *that method itself has some problems, but they are moot, since PPL did not use the zero*
6 *intercept methodology in its attempt to determine customer costs.*

7 Q. IS THE AMOUNT OF CAPACITY THAT CAN BE PROVIDED BY A 30 KVA
8 TRANSFORMER AND INCLUDED IN PPL'S CUSTOMER COST
9 DETERMINATION A SIGNIFICANT CONCERN?

10 A. Yes. PPL reports on pages 159-160 of Exhibit JMK-1, for example, that Residential RS
11 customers have class maximum demands of 3,259,454 kW. Page 80 of that same exhibit
12 shows the number of Residential RS year-end customers at 1,149,925 customers. This
13 equates to each Residential RS customer contributing 2.8 kW to the peak residential class
14 demand, whenever throughout the year the residential class demand peaks. Granted,
15 there is diversity among customer demands and several customers may be served from
16 one transformer, but the 30 kVA size transformer that PPL currently installs is capable of
17 providing for about 25 kW of demand and does, in fact, meet the peak demands of many
18 residential customers. Moreover, prudent planning requires the installation of
19 transformers that do, in fact, meet the peak demand of all customers served from the
20 installed transformer (and typically, prudent planning also requires expected load growth
21 to be considered when sizing transformers, as well).

22 The minimum sized system methodology as applied by PPL in this case to
23 estimate customer costs includes significant capacity costs, which are then misallocated
24 on a customer basis. Because PPL's Residential RS customers account for fully 83
25 percent of the customers receiving an allocated share of the customer related overhead

1 line transformer costs, the overstatement of customer costs leads to particularly
2 overstated costs of serving residential customers.

3 Each type of Common Distribution plant that PPL identifies as customer related
4 suffers from the same malady as PPL's overhead line transformers -- the inclusion of
5 capacity related costs in the minimum sized system. For example, PPL's minimum sized
6 underground line transformers have 50 kVA of capacity. PPL's minimum overhead and
7 underground lines can each provide capacity, and PPL's minimum sized poles can
8 support the capacity carrying lines and line transformers. In each case, customer costs
9 are overstated since the customer related plant also includes the provision of capacity.
10 Allocating the capacity related costs included in all these customer components on a
11 customer count basis instead of a demand basis overstates the allocated costs of providing
12 service to PPL's smaller customers.

13 Q. PLEASE EXPLAIN YOUR SECOND CONCERN REGARDING HOW PPL
14 ALLOCATED ITS PROPOSED DEMAND RELATED COSTS IN THOSE
15 COMMON DISTRIBUTION COST ACCOUNTS ALLEGED TO HAVE BOTH
16 CUSTOMER AND DEMAND RELATED COST RESPONSIBILITY.

17 A. PPL believes that its Common Distribution plant accounts housing its investment in lines,
18 poles and transformers contain both a customer related cost component and a demand
19 related cost component. PPL deducts its calculated customer costs from the total plant
20 account costs for each of its lines, poles and transformer accounts and reasons that the
21 plant costs in excess of customer costs are related to the maximum noncoincident
22 demands PPL's customers place on its distribution delivery system. PPL allocates this
23 demand related portion of the plant account balances on the basis of the ratio of each
24 customer class' noncoincident peak demand to the total of all class' noncoincident peak
25 demands.

1 Q. CAN YOU EXPLAIN WHY THERE IS A PROBLEM WITH PPL'S
2 ALLOCATION OF THE DEMAND RELATED PORTION OF COSTS IN
3 THOSE PLANT ACCOUNTS THAT PPL BELIEVES HAVE BOTH
4 CUSTOMER AND DEMAND RELATED COSTS?

5 A. Yes. As discussed immediately above, PPL has included capacity costs in its customer
6 component of its poles, lines and transformer plant accounts. Thus, a portion of the
7 distribution capacity costs that are related to customer demands has already been
8 allocated (albeit improperly on a customer-count basis) to PPL customers. The problem
9 with PPL's allocation of the remaining demand related portion of costs is that PPL does
10 not recognize the customer demands that can be accommodated by the capacity it has
11 included in its customer cost determination. Because PPL gives no recognition that a
12 portion of each customer class' peak demands can be met with the customer related plant
13 costs that, in fact, include capacity, a "double count" results, producing an overallocation
14 of demand costs to classes containing relatively large numbers of customers.

15 Q. PLEASE GIVE AN EXAMPLE OF HOW PPL'S ALLOCATION OF THE
16 DEMAND RELATED PORTION OF COSTS IN THOSE PLANT ACCOUNTS
17 HAVING BOTH CUSTOMER AND DEMAND RELATED COSTS RESULTS
18 IN A MISALLOCATION OF COSTS.

19 A. Customers whose loads are served by a 30 kVA transformer or smaller obviously have all
20 of their capacity requirements provided for in their customer allocation of costs. This
21 being the case, these customers should not also be responsible for an allocation of any
22 demand related transformer costs. In general, the demands that are provided for and
23 included in the minimum sized customer cost determinations, be they the total demands
24 of some customers or a portion of the demands of other customers, should be excluded
25 from the allocation of capacity related costs associated with meeting higher demands.

1 PPL has failed to remove the demands that can be met with its minimum sized system
2 from also bearing cost responsibility for the demand portion of plant accounts having
3 both customer and demand related costs in the Company's studies.

4 Because the capacity included in the minimum sized system is a greater
5 percentage of smaller customer demands, PPL's failure to remove the demands which
6 can be met with the minimum sized system from the demands on which the capacity
7 related portion of the subject accounts are allocated, is particularly detrimental to PPL's
8 smaller customers.

9 Q. THE THIRD PROBLEM YOU MENTIONED WITH REGARD TO PPL'S
10 CUSTOMER/DEMAND DETERMINATION RELATES TO PPL
11 INCREASING THE SIZE OF THE MINIMUM SIZED SYSTEM UPON
12 WHICH IT DETERMINES CUSTOMER COSTS. PLEASE EXPLAIN THIS
13 CONCERN.

14 A. Customer costs should include no capacity costs. In PPL's last general rate case, PPL
15 based the customer cost determination of its overhead line transformers on the costs of its
16 10 kVA transformers, the smallest size then currently being installed. In that prior case,
17 PPL proposed that the customer component of its line transformers was equal to 23
18 percent of its line transformer investment. In this present case, PPL proposes to base its
19 customer component of overhead line transformers on the costs of its 30 kVA
20 transformers, the smallest size PPL now installs. PPL's approach suggests that,
21 coincidentally with its decision to increase the minimum size of the overhead line
22 transformers it installs from 10 kVA to 30 kVA, that the customer component of all of its
23 316,318 overhead line transformers has suddenly increased to 63 percent of its line
24 transformer investment, commensurate with its decision to increase the minimum size of
25 its installed transformers. This result is especially troubling when one recalls that the

1 customer cost PPL is trying to measure with its minimum sized system is supposed to be
2 independent of any capacity related cost, and indeed, would theoretically contain no
3 capacity related cost. This relationship in PPL's cost of service studies between capacity
4 size and resultant customer cost determinations, coupled with PPL's proposed increase in
5 the capacity of its minimum sized system, simply produces incredible customer cost
6 determinations.

7 Q. WHAT DO YOU CONCLUDE FROM YOUR REVIEW OF PPL'S COST OF
8 SERVICE STUDIES?

9 A. Based on:

- 10 – PPL's overstatement of customer costs through the inclusion of capacity, or demand
11 related costs, in the customer cost category, coupled with PPL's allocation of the
12 capacity related costs on a customer-count basis;
13
- 14 – PPL's overallocation of the demand related portion of its *Common Distribution*
15 facilities costs to customers whose total or partial demands can be provided for with
16 PPL's *minimum sized equipment*; and
17
- 18 – PPL's customer cost determinations' dependence on PPL's selection of what
19 constitutes a minimum sized system, and PPL's increasing the capacity of its
20 minimum sized system when customer costs should be totally independent of
21 capacity;
22

23 I conclude that PPL's cost of service study results are an unreliable indication of the
24 adequacy of revenue components as compared to allocated costs. *Common Distribution*
25 plant accounts that contain the misallocations I have discussed so far, affect 50 percent of
26 the dollar value of PPL's distribution plant accounts. A class cost of service study

1 compares each class' revenues to each class' allocated costs of service in order to assist
2 in the determination of reasonable rates. Because PPL's major categories of costs have
3 been improperly determined and misallocated, PPL's cost of service study results do not
4 present a useful guide to the Commission for use in the setting of rates in this proceeding.
5

6 **An Alternative Allocation of PPL's Common Distribution Plant**

7 Q. ARE THERE OTHER COST OF SERVICE STUDIES THAT CAN BE USED
8 TO ASSESS THE COSTS ASSOCIATED WITH THE PROVISION OF
9 SERVICE TO PPL'S SEVERAL CUSTOMER CHARGES?

10 A. Yes. There are numerous cost study variants that can be used to allocate PPL's average,
11 embedded, historic costs among PPL's several customer classes. Cost allocations will
12 vary among these studies to address the concerns or to represent the differing views of
13 cost practitioners performing the studies. For example, PPL has performed its 2004 class
14 cost of service study in such a manner that it concludes that \$919 million dollars, or 45
15 percent of its total Common Distribution plant costs for overhead line, underground lines
16 and line transformers, is customer related. Professor James Bonbright warns of using the
17 customer cost category as a dump for the costs of minimum sized system. At page 492 of
18 his Principles of Public Utility Rates text, Professor Bonbright puts it this way:

19
20 ...But if the hypothetical cost of a minimum-sized distribution system is
21 properly excluded from the demand-related costs for the reason just given,
22 while it is also denied a place among the customer costs for the reason
23 stated previously, to which cost function does it then belong? The only
24 defensible answer, in our opinion, is that it belongs to none of them.
25 Instead, it should be recognized as a strictly unallocable portion of total
26 costs. And this is the disposition that it would probably receive in an
27 estimate of long-run marginal costs. But fully-distributed cost analysts
28 dare not avail themselves of this solution, since they are the prisoners of
29 their own assumption that "the sum of the parts equals the whole." They
30 are therefore under impelling pressure to fudge their cost apportionments
31 by using the category of customer costs as a dumping ground for costs that

1 they cannot plausibly impute to any of their other cost categories.

2 [Emphasis added]

3 Clearly, how the costs that PPL ascribes to the customer cost function are allocated is
4 controversial, at best.

5 Q. IS THERE ANOTHER VIEW AS TO HOW PRIMARY DISTRIBUTION
6 PLANT AND DISTRIBUTION COSTS RELATED TO POLES, LINES AND
7 TRANSFORMERS MAY BE REASONABLY ALLOCATED?

8 A. Yes. PPL has allocated the subject costs on two bases: One, that customers exist, and
9 two, that customers have a peak demand during one hour of a typical year's 8,760 hours.
10 Quite frankly, from a practical point of view, if PPL only had potential customers who
11 merely wanted to be hooked up to an electric system and those potential customers only
12 wanted to use electricity one-hour per year, PPL's distribution system, with its attendant
13 costs, would not be practical. From a financial perspective, if PPL faced a market
14 characterized by customers who wanted to be hooked up so they could use electricity
15 only one-hour per year, PPL would have difficulty raising capital for such an enterprise.
16 In short, PPL's proposed allocation, totally omitting customers usage, or commodity, and
17 driven only by the existence of one, the number of customers and two, peak demands
18 during the one-hour per year when the classes peak, does not result in costs being
19 allocated on the basis of the services causing those costs to be incurred.

20 Q. WHAT SERVICE DEMANDS HAVE CAUSED THE COSTS RELATED TO
21 PPL'S PROVISION OF DISTRIBUTION DELIVERY SERVICE?

22 A. The demands for delivered electricity, both in annual amounts sufficient to warrant PPL's
23 existence and in amounts that reflect maximum demands, cause the costs that PPL seeks
24 to recover in this proceeding. These demands for electricity are what economists call
25 "derived demands." Electricity is not demanded for its own sake; rather, electricity is
26 demanded because people have a demand for things like warmed and cooled living and

1 working spaces, refrigerated and frozen and cooked foods, warm water showers, clean
2 and dried clothes, home and business video and audio entertainment or presentations, or
3 the desire to see clearly at night, and in general, the use of all the other electricity-using
4 appliances and equipment that are used to satisfy the revealed demands of market
5 participants. The use of all these electricity-using appliances creates the demands for
6 delivered electricity on PPL's system. These demands exist year-round, creating an
7 annual demand for electric service. Without this annual demand in sufficient amounts
8 there would be no PPL costs of service because there would be no PPL electric
9 distribution system. It is the sustained demand for electricity, which is ultimately
10 responsible for PPL's existence, and costs, which has been relieved of any cost
11 responsibility by PPL in its proposals to allocate its total costs of providing service.

12 Now, if the annual demand for electricity delivered across PPL's distribution
13 system were an absolutely level amount each day of the year and each hour of the day,
14 PPL's distribution system would only have to be built to deliver this average hourly
15 amount of capacity. A system designed to meet this constant average demand is the
16 smallest sized system that could deliver the annual energy requirements of PPL's
17 customers. But electricity demands are not constant. At times, the demands for
18 electricity delivery are higher than at other times. PPL distribution company exists not
19 only to service its customers' average delivery service requirements, but PPL must also
20 stand ready to meet elevated delivery service requirements whenever they exist
21 throughout the year. From this perspective it is the annual, or average service demands,¹
22 and the elevated, or peak demands, that cause PPL to incur its costs of providing service.
23 Consistent with this practical, realistic view of PPL's delivery service operations

¹ Average demands for service bear the same relationship as annual demands, since average demands are annual demands divided by a constant 8,760 hours.

1 (compared to PPL's view that its costs are driven by number of customers and their one-
2 hour per year peak demands only) PPL's Primary and Common Distribution costs are
3 related partially to PPL's customers' average demands for service and partially to
4 customers' peak demands for service.

5 Q. HAVE YOU PREPARED A STUDY BASED ON THE VIEW THAT PPL'S
6 DELIVERY COSTS ARE CAUSED BY CUSTOMERS' ANNUAL, OR
7 AVERAGE, DEMANDS, AND BY CUSTOMERS HAVING ELEVATED
8 DEMANDS THAT PRODUCE, AT SOME TIME DURING THE YEAR,
9 CUSTOMER CLASS PEAK DEMANDS?

10 A. Yes. Because the Company said its cost of service model is proprietary, I specified
11 allocation factors to apply to PPL's Primary Distribution and Common Distribution plant,
12 and PPL re-ran its cost study. Schedule RAG-1 contains the summary pages of class cost
13 of the service studies that allocate Primary Distribution costs and Common Distribution
14 costs partially on the basis of class average demands and partially on the basis of class
15 peak demands. Those study results are based on 50 percent weighting of average
16 demands and a 50 percent weighting of peak demands. Theoretically, the capacity
17 required to deliver average demands could properly be based on the ratio of average
18 demands to peak demands, which is simply the definition of system load factor, because
19 no smaller system capacity could deliver the annual demands for electricity on the PPL
20 system. PPL has a system load factor in excess of 50 percent, but the studies reported in
21 Schedule RAG-1 weight average demand cost responsibility at 50 percent so as to present
22 a conservative restatement of costs that are caused by the annual, or average, demands for
23 electricity by PPL's customers. Because PPL's Primary and Common Distribution plant
24 must be sized to not only accommodate PPL's average demands, but to also deliver

1 electricity at times of peak demand, the remaining Primary and Common Distribution
2 plant costs have been allocated on class noncoincident peak demands.

3 Q. PLEASE COMPARE THE RESIDENTIAL RS CUSTOMER COST STUDY
4 RESULTS PRODUCED BY YOUR ALTERNATIVE COST STUDY TO THE
5 RESULTS FOUND IN PPL'S COST STUDIES.

6 A. Schedule 2 contains a table showing the overall jurisdictional and the Residential RS cost
7 of service study results at both present and proposed rates for both the historic 2003 test
8 year and for the future test year 2004. When costs are allocated on the basis of the
9 service requirements which drive, or cause the costs to be incurred, including average
10 demands and elevated demands as explained above, the cost misallocations inherent in
11 PPL's studies are removed. Under my study Residential RS customers show an index
12 return of 91 percent at present rates (historic test year) increasing to 93 percent under
13 PPL proposed rates. The PPL study suggests those Residential index returns are only 46
14 percent and 64 percent, respectively.

15 On a future test year basis, my studies show the Residential RS customers
16 produce a 75 percent index return, rising to 82 percent at proposed rates. Again, the PPL
17 study shows substantially lower index returns of only 41 percent and 60 percent,
18 respectively.² All the results relate to PPL now being a distribution only company.
19 These study results are shown at PPL's proposed rates for illustrative purposes. I do not
20 endorse PPL's requested overall increase.

21
22 **Allocation of Universal Service Costs.**

23 Q. PPL ALLOCATED UNIVERSAL SERVICE COSTS ONLY TO
24 RESIDENTIAL CUSTOMERS IN ITS CLASS COST OF SERVICE STUDY.

² These reported PPL index returns correct PPL's cost of service studies for computational errors.

1 HAVE NON-UNIVERSAL SERVICE RESIDENTIAL CUSTOMERS CAUSED
2 THE UNIVERSAL SERVICE COSTS?

3 A. OCA witness Colton discusses this issue in detail. No PPL service that is provided to
4 non-universal service recipients has caused these costs. An allocation of these costs on
5 an energy or total revenue basis to all customer classes least distorts allocated costs of
6 service, and results in a broad sharing of these otherwise non-allocable costs. A broader
7 allocation of these costs to all customer classes would increase somewhat the index rates
8 of return for residential customers reported above.

9
10 **III. Proposed Revenue Allocation**

11 Q. DO YOU TAKE ISSUE WITH PPL'S PROPOSED SPREAD OF ITS RATE
12 INCREASE AMONG THE VARIOUS CUSTOMER CLASSES?

13 A. No. I am accepting PPL's proposed rate spread. PPL's proposed rate spread limits each
14 class' increase to 10 percent on a total bill basis. Also, under PPL's proposed rate spread,
15 resulting class index returns move closer to unity. PPL's rates incorporate the principle
16 of gradualism in moving index returns for one limited, specific, unbundled service
17 element, in this case Distribution service, toward unity, especially during the transition
18 period adopted to ultimately achieve fully unbundled rate determinations for all
19 components of service.

20 While my cost of service study results show that Residential RS customers are
21 providing revenues closer to their allocated costs of service than PPL's studies show,
22 there is some room to move the classes closer to PPL's overall rate of return. Like PPL, I
23 have not utilized my cost of service study results directly to determine the proposed rate
24 spread. Many Commissions, including the PAPUC, believe as I do that average,
25 embedded class cost of service studies of the type performed in this case can be a useful

1 guide, or a starting place, in the consideration of the reasonableness of rates. Other
2 considerations, such as gradualism, stability, understandability, acceptance, simplicity,
3 etc., are also important considerations Commissions have considered in the setting of
4 rates.

5 Q. IS THERE ANOTHER REASON TO GENERALLY MOVE GRADUALLY
6 TOWARD SYSTEM AVERAGE RATE OF RETURN?

7 A. Yes. I have included Schedule RAG-3, which are the summary pages from PPL's last
8 rate proceeding showing class rates of return for the then vertically integrated PPL
9 operations. This study reflects the same methodological approach to distribution costs
10 that is proposed by PPL in this case. In the last case, PPL calculated that Residential RS
11 customers generated an 80 percent index return, when generation costs and total rates
12 were considered. We are now in transition to a new environment of unbundled electric
13 service rates. Now, PPL studies of its distribution only operations show index returns at
14 41 percent and 60 percent for the future test year under present and proposed rates,
15 respectively. If unbundling services and rates, and performing a cost of service study
16 addressing only a portion of prior total costs of service, using the same methodology as
17 was previously used prior to unbundling, shows a reduced rate of return for customers
18 continuing to purchase PPL's remaining, limited unbundled distribution service, this
19 suggests higher returns for unbundled operations that are no longer subject to
20 Commission jurisdiction. While the generation rate cap continues and all rate elements
21 are not determined together in the competitive and regulated markets, gradually
22 increasing rates for the limited, specific remaining service, which accounts for only a
23 piece of the total rate for delivered electricity, is the most reasonable approach. PPL's
24 proposed revenue spread properly reflects these points.

1 Q. IF PPL IS AWARDED LESS THAN ITS FULL RATE INCREASE REQUEST,
2 WHAT RATE SPREAD DO YOU RECOMMEND?

3 A. No class receiving a rate reduction under PPL's proposed rate spread should receive an
4 additional rate reduction. All other classes should experience a proportionate reduction
5 from proposed rates, commensurate with any reduction in the requested distribution rate
6 increase.

7
8 **IV. Rate Design**

9 Q. PLEASE DESCRIBE PPLS' PROPOSED RESIDENTIAL RS RATE DESIGN
10 CHANGES.

11 A. Below is a comparison of PPL's present and proposed Residential RS rates shown on Mr.
12 Kasper's Attachment IV-C, page 1.

13

	Present Rate	Proposed Rate
Distribution Charge	\$6.55	\$12.20
First 200 kWh	1.817¢ per kWh	0.000¢ per kWh
Next 600 kWh	1.612¢ per kWh	2.198¢ per kWh
Over 800 kWh	1.489¢ per kWh	1.879¢ per kWh

14
15 The proposed Distribution Charge rate increase of \$5.65, an increase in excess of 86
16 percent, is obviously high, and out of proportion to the 28 percent Residential RS
17 proposed distribution service revenue increase. PPL has proposed a price of zero for
18 each kWh consumed between 0 and 200 kWh. PPL also proposes to increase its 200 to
19 800 kWhs block rate by 38 percent while proposing a 28 percent tailblock rate increase.
20 The tailblock per kWh price discount compared to middle block consumption is proposed
21 to essentially double under proposed rates showing a proposed 14.5 percent discount
22 compared to the current tailblock rate discount of 7.7 percent.

23 PPL's proposed Distribution Charge increase should be rejected. At an 86
24 percent proposed increase, it is too large. Also, as I discuss later in my testimony, PPL's

1 proposed Distribution Charge exceeds reasonably determined Distribution Charge costs.
2 To the extent that PPL's inordinately large Distribution Charge proposal finances its
3 proposal to provide the first 200 kWh's per month "free" upon payment of the
4 Distribution Charge, the proposed charge is excessive. Finally, no basis has been
5 advanced by PPL to support its proposed disproportionate increase in its 200-800 kWh
6 block rate or its proposal to dramatically increase its tailblock rate discount.

7 Q. IS IT APPROPRIATE TO INCLUDE 200 KWH IN THE RESIDENTIAL RS
8 DISTRIBUTION CUSTOMER CHARGE?

9 A. No. PPL's proposal to include 200 kWh in a monthly customer charge is known as a
10 "minimum bill" concept. Under a minimum bill, the customer, bearing no price for
11 additional delivery service, bears no additional cost by consuming that service up to the
12 amount included in the minimum bill. Costs of PPL's delivery system do not commence
13 with the delivery of a customer's 201st kWh, but are applicable to all energy deliveries.
14 Moreover, customer costs authorized for inclusion in the monthly Distribution charge in
15 Pennsylvania do not include an allowance for the provision of a block of free delivery
16 service.
17

18 Q. HAVE YOU DETERMINED PPL'S RESIDENTIAL CUSTOMER COSTS FOR
19 INCLUSION IN PPL'S DISTRIBUTION CHARGE?

20 A. Yes. Schedule RAG-4 shows the determination of PPL's customer costs eligible for
21 inclusion under my understanding of Commission precedent. In Pennsylvania, customer
22 costs included in a monthly fixed charge, such as PPL's Distribution Charge, include
23 return, taxes on return, and depreciation on services plant and meter plant. The return
24 and taxes costs are \$41.9 million, as shown on Schedule RAG-4. Other fixed costs
25 included in the Distribution Charge are the \$10.0 million and \$6.3 million of depreciation

1 expense on services and meters plant. Also considering variable O&M costs included in
 2 the Distribution Charge, as shown on Schedule RAG-4, results in total Distribution
 3 Charge costs of \$108.166 million. Utilizing the costs shown on Schedule RAG-4, the
 4 calculated monthly Distribution Charge would be \$7.83. A more economically
 5 meaningful Distribution Charge price signal would exclude the fixed costs, or
 6 depreciation expense and return and taxes, from the Distribution Charge determination.
 7

8 Q. WHAT RATE DESIGN DO YOU RECOMMEND FOR PPL'S RESIDENTIAL
 9 RS CUSTOMERS?

10 A. For illustrative purposes and a direct comparison to PPL's proposed rates, I show below a
 11 Residential RS rate design consistent with PPL's proposed \$377,749,588 Residential RS
 12 Distribution Rate Revenue shown on Attachment IV-C, page 1 of Mr. Kasper's
 13 attachments.
 14

	Present Rate	OCA Proposed Rate
Distribution Charge	\$6.55	8.00
First 200 kWh	1.817¢ per kWh	2.292¢ per kWh
Next 600 kWh	1.612¢ per kWh	2.087¢ per kWh
Over 800 kWh	1.489¢ per kWh	1.964¢ per kWh

15 The \$1.45 Distribution Charge increase is slightly in excess of customer costs
 16 calculated in accord with my understanding of Pennsylvania Commission precedent on
 17 this issue. All other block rate prices have been increased by the same absolute 0.475
 18 cents per kWh amount. These proposed rates are consistent with PPL's current three-
 19 block rate design. PPL was granted its requested authority to increase its rate blocks
 20 from two to three in its last rate case. Continuity, stability, customer understanding and
 21 acceptance suggest that PPL's proposal to effectively eliminate its Commission-approved
 22 additional rate block in order to accommodate PPL's inordinately large Distribution
 23 Charge increase should be denied. The proposed, equal, absolute 0.475 cents per kWh

1 increase is consistent with average, embedded cost of service study results. These cost of
2 service studies do not determine costs by consumption level.

3 Q. WHAT RATE DESIGN DO YOU RECOMMEND FOR THE RESIDENTIAL
4 THERMAL STORAGE RATE?

5 A. The Residential Thermal Storage Rate RTS is a grandfathered rate, closed to new
6 participants. PPL has proposed to maintain the current RTS distribution rate design
7 consisting of a monthly Distribution Charge and a charge for on-peak kW's in excess of 2
8 kW. However, PPL proposes a \$5.00 Distribution Charge increase to \$20.20, which is so
9 large that PPL proposes to reduce the per kW charge from 90 cents per kW to 56 cents.
10 For simplicity, I propose that this small group of grandfathered residential service
11 customers pay the same \$1.45 Distribution Charge increase as the 1.1 million regular
12 residential service customers. The remainder of increased RTS revenues would be
13 recovered from the remaining per kW rate element. Specifically, the RTS distribution
14 rate, reflecting these recommended procedures would be:
15

	Present Rate	Proposed Rate
Distribution Charge	\$15.21	\$16.66
On-peak kW in excess of 2 kW	0.90¢ per kW	1.25 per kW

16
17 Q. DOES THIS COMPLETE YOUR TESTIMONY?

18 A. Yes.

19
20 00080012

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)	
UTILITY COMMISSION)	
)	
v.)	DOCKET NO. R-00049255
)	
PPL ELECTRIC UTILITIES)	
CORPORATION)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JUNE 2004

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTH ENDED 12/31/2004
COMPONENTS OF OPERATING EXPENSES WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
\$1,000

Line No.	Input	Alloc P21	Output	Pa Jurisdct Distribution Only oca 11 8/02 FTY2004	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	
OPERATING REVENUES AT PRESENT RATE LEVELS												
SALES OF ELECTRICITY												
1	TREV			0	0	0	0	0	0	0	0	
2	DREV			495,418	293,820	3,513	61,460	84,182	21,873	1,757	1,774	
3	STAS			0	0	0	0	0	0	0	0	
4	TOTAL SALE OF ELECTRICITY			495,418	293,820	3,513	61,460	84,182	21,873	1,757	1,774	
5	S11	RCW4	RRT	5,888	3,488	32	994	1,004	271	7	0	
6	TOTAL ADJUSTED SALES OF ELECTRICITY			501,304	297,408	3,545	62,454	85,186	22,144	1,764	1,774	
7	ANNUALIZATION PRESENT REVENUES			4,128	2,754	21	972	874	(414)	25	(115)	
8	ANNUAL ADJD SALE OF ELECT			505,432	300,160	3,566	63,426	86,060	21,730	1,789	1,659	
9	OTHER OPERATING REVENUES			17,778	9,823	434	1,427	4,132	789	50	13	
10	TOTAL OPERATING REVENUES			623,208	310,083	4,000	64,853	90,192	22,489	1,839	1,872	
OPERATING EXPENSES												
OPERATING AND MAINTENANCE EXPENSES												
11	TRANSMISSION			0	0	0	0	0	0	0	0	
12	DISTRIBUTION			127,707	70,485	3,002	10,048	27,437	6,480	382	138	
13	OTHER OPER & MAINT EXPENSES			182,129	133,777	2,682	13,795	21,082	4,319	461	552	
14	TOTAL OPER & MAINT EXPENSES			309,836	204,272	5,684	23,844	48,519	9,808	823	690	
DEPRECIATION EXPENSE												
15	TRANSMISSION			0	0	0	0	0	0	0	0	
16	DISTRIBUTION			78,408	43,818	1,854	6,242	16,848	2,887	176	88	
17	OTHER DEPREC EXP			15,499	9,887	323	1,334	2,877	457	30	11	
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSES			93,905	53,705	2,177	7,576	19,525	3,124	206	100	
TAXES												
19	CAPITAL STOCK PRESENT LEVEL			5,587	3,172	137	452	1,270	225	15	5	
20	OTHER OTHER TAXES			9,200	5,758	198	784	1,712	301	19	8	
21	DEFERRED INCOME TAXES			30,482	17,489	717	2,438	8,747	1,158	81	27	
22	NET INVESTMENT TAX CREDIT			(1,813)	(1,089)	(47)	(154)	(444)	(81)	(5)	(1)	
23	GROSS RECEIPTS TAX			29,821	17,709	210	3,742	6,078	1,282	106	98	
24	TOTAL PA INCOME TAX			(170)	(1,845)	(825)	2,237	(323)	437	43	89	
25	TOTAL FED INC TAX			(25,502)	(19,778)	(2,565)	5,067	(6,459)	445	73	193	
26	TOTAL TAXES			47,485	21,418	(1,975)	14,584	7,581	3,787	332	397	
27	TOTAL OPERATING EXPENSES			451,206	279,385	5,888	45,984	75,825	16,700	1,361	1,187	
28	RETURN (LN 11 - 36)			72,002	30,888	(1,888)	18,889	14,567	5,799	478	485	
29	TOTAL RATE BASE			1,842,818	1,049,843	45,813	148,288	421,405	73,950	4,905	1,843	
30	RATE OF RETURN (LN 47 / LN 48)			PRRTR	3.81%	2.82%	-4.12%	12.72%	3.48%	7.84%	9.75%	24.96%
31	CLASS RATE IN % OF TOTAL			PRCLR1	100.00%	74.88%	-105.37%	325.32%	88.48%	200.51%	249.36%	838.38%

PA PUBLIC UTILITY COMMISSION
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PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTH ENDED 12/31/2004
COMPONENTS OF OPERATING EXPENSES WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
\$1,000

Line No.	Input	Alloc P21	Output	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
	OPERATING REVENUES AT PRESENT RATE LEVELS									
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES	TREV		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES	DREV		1,717	283	314	662	6,222	17,705	38
3	STATE TAX ADJ SURCHARGE	STAS		0	0	0	0	0	0	0
4	TOTAL SALE OF ELECTRICITY		RRT	1,717	283	314	662	6,222	17,705	38
5	LATE PAY CHARGES PRESENT RATES	S11 RCW4	R11	0	0	0	0	52	40	0
6	TOTAL ADJUSTED SALES OF ELECTRICITY		RRTT	1,717	283	314	662	6,274	17,745	38
7	ANNUALIZATION PRESENT REVENUES		ANN	(11)	(2)	(33)	(41)	190	(93)	1
8	ANNUAL ADJD SALE OF ELECT		ARTT	1,706	281	281	621	6,464	17,652	37
9	OTHER OPERATING REVENUES		ROOT	4	1	16	2	296	709	1
10	TOTAL OPERATING REVENUES		ROT	1,710	282	297	623	6,759	18,361	38
	OPERATING EXPENSES									
	OPERATING AND MAINTENANCE EXPENSES									
11	TRANSMISSION		EE20	0	0	0	0	0	0	0
12	DISTRIBUTION		EE30	48	9	24	20	2,016	8,808	12
13	OTHER OPER & MAINT EXPENSES		EEOT	473	54	77	32	1,533	3,281	4
14	TOTAL OPER & MAINT EXPENSES		EE00	521	63	101	52	3,549	11,889	16
	DEPRECIATION EXPENSE									
15	TRANSMISSION		ED20	0	0	0	0	0	0	0
16	DISTRIBUTION		ED30	31	6	3	12	1,241	5,414	8
17	OTHER DEPREC EXP		EDOT	3	0	6	2	200	567	0
	TOTAL DEPRECIATION AND									
18	AMORTIZATION EXPENSE		ED00A	34	6	9	14	1,441	5,981	8
	TAXES									
19	CAPITAL STOCK PRESENT LEVEL		ET1	2	0	3	1	92	183	0
20	OTHER OTHER TAXES		ET001	2	0	5	0	125	285	0
21	DEFERRED INCOME TAXES		TXTA	18	2	23	3	484	1,289	2
22	NET INVESTMENT TAX CREDIT		TX93	0	0	(2)	0	(32)	(77)	0
23	GROSS RECEIPTS TAX		TXG	101	17	17	37	381	1,041	2
24	TOTAL PA INCOME TAX		TSIT1	100	19	13	51	(8)	(337)	0
25	TOTAL FED INC TAX		TFTX	308	59	40	157	(423)	(2,617)	(1)
26	TOTAL TAXES		TFIT1	531	97	99	249	819	(223)	3
27	TOTAL OPERATING EXPENSES		TEXP1	1,086	188	209	315	5,609	17,647	27
28	RETURN (LN 11 - 38)		PRERTM	624	116	88	308	1,150	714	11
29	TOTAL RATE BASE		RBX	685	136	950	271	30,865	63,576	167
30	RATE OF RETURN (LN 47 / LN 48)		PRRTR	91.09%	84.06%	9.26%	113.65%	3.73%	1.12%	8.58%
31	CLASS RATE IN % OF TOTAL		PRCLRT	2329.87%	2149.87%	236.83%	2806.65%	95.40%	28.64%	168

PPL ELECTRIC UTILITIES CORPORATION
 COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2004
 OPERATING REVENUES AT PROPOSED RATE LEVELS
 \$1,000

Line No.	Input	Alloc P23	Output	Pa Jurisdct	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
				Distribution Only oca 11 8/02 FTY2004							
OPERATING REVENUES AT PROPOSED RATE LEVELS											
SALES OF ELECTRICITY											
1	TRANSMISSION REVENUES	TREVP	0	0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES	DREVP	657,763	374,883	4,081	83,476	127,283	32,823	2,141	1,793	
3	STATE TAX ADJ SURCHARGE	STAS	0	0	0	0	0	0	0	0	
4	TOTAL SALE OF ELECTRICITY		657,763	374,883	4,081	83,476	127,283	32,823	2,141	1,793	
5	LATE PAY CHARGES PROPOSED	R11P	6,474	3,834	38	1,093	1,105	298	7	0	
6	TOT ADJUSTED SALE OF ELECTRICITY	RRTP	664,237	378,717	4,117	84,569	128,388	32,821	2,148	1,793	
7	ANNUALIZATION PROPOSED REVS	ANNP	6,651	3,553	25	1,335	1,293	(585)	30	(108)	
8	TOT ADJUSTED SALE OF ELECTRICITY	ARTTP	669,888	382,270	4,142	85,904	129,681	32,356	2,178	1,685	
9	OTHER OPERATING REVENUES	ROOT	17,776	9,823	434	1,427	4,132	789	50	13	
10	TOTAL OPERATING REVENUES	ROTP	687,664	392,193	4,576	87,331	133,813	33,125	2,228	1,698	
OPERATING EXPENSES											
OPERATING AND MAINTENANCE EXPENSES											
11	TRANSMISSION	EE20	0	0	0	0	0	0	0	0	
12	DISTRIBUTION	EE30	127,707	70,495	3,002	10,049	27,437	5,490	362	138	
13	OTHER OPER & MAINT EXPENSES	EE0T	182,128	133,777	2,882	13,795	21,082	4,319	481	552	
14	TOTAL OPER & MAINT EXPENSES	EE00	309,835	204,272	5,884	23,844	48,519	9,809	823	690	
DEPRECIATION EXPENSE											
15	TRANSMISSION	ED20	0	0	0	0	0	0	0	0	
16	DISTRIBUTION	ED30	78,406	43,818	1,854	6,242	16,848	2,687	176	89	
17	OTHER DEPRECIATION EXPENSE	ED0T	15,499	9,887	323	1,334	2,677	457	30	11	
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00	93,905	53,705	2,177	7,576	19,525	3,124	206	100	
TAXES											
19	CAPITAL STOCK PROP LEVEL	ET1P	5,287	3,001	130	427	1,201	213	14	5	
20	OTHER-W/O CAP STOCK	ET001	10,131	6,286	221	860	1,927	340	22	7	
21	DEFERRED INCOME TAXES	TXTA	30,482	18,198	740	2,534	6,928	1,190	83	28	
22	NET INVESTMENT TAX CREDIT	TX93	(1,913)	(1,089)	(47)	(154)	(444)	(81)	(5)	(1)	
23	GROSS RECEIPTS TAX	TXG	39,523	22,554	244	5,066	7,651	1,909	129	99	
24	TOTAL PA INCOME TAX	TSIT1	15,227	5,838	(573)	4,345	3,763	1,433	79	72	
25	TOTAL FED INC TAX	TFTX	23,052	4,453	(2,399)	11,715	6,426	3,586	188	201	
26	TOTAL TAXES	TFIT1	121,749	58,532	(1,707)	24,897	27,271	8,558	508	410	
27	TOTAL OPERATING EXPENSES	TEXP1	525,490	316,509	6,154	56,117	95,315	21,481	1,537	1,200	
28	RETURN (LN 11 - 36)	PRRTN	182,174	76,684	(1,576)	31,214	38,498	11,634	691	488	
29	TOTAL RATE BASE	RBX	1,842,816	1,049,843	45,813	148,288	421,405	73,950	4,905	1,943	
30	RATE OF RETURN (LN 47 / LN 48)	PRRTR	8.80%	7.21%	-3.44%	21.05%	9.14%	15.73%	14.08%	25.83%	
31	CLASS RATE IN % OF TOTAL	PRCLRT	100.00%	81.93%	-39.09%	239.20%	103.86%	176.75%	180.11%	291.25%	

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2004
OPERATING REVENUES AT PROPOSED RATE LEVELS
\$1,000

Line No.	Input	Alloc P23	Output	IST	LP-8	LPEP	ISA	GH	SL/AL	L5-S
OPERATING REVENUES AT PROPOSED RATE LEVELS										
SALES OF ELECTRICITY										
1	TRANSMISSION REVENUES	TREVP		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES	DREVP		1,152	185	404	661	9,193	19,805	83
3	STATE TAX ADJ SURCHARGE	STAS		0	0	0	0	0	0	0
4	TOTAL SALE OF ELECTRICITY		RRTP	1,152	185	404	661	9,193	19,805	83
5	LATE PAY CHARGES PROPOSED		R11P	0	0	0	0	57	44	0
6	TOT ADJUSTED SALE OF ELECTRICITY		RRTP	1,152	185	404	661	9,250	19,849	83
7	ANNUALIZATION PROPOSED REVS		ANNP	(7)	(1)	(43)	(42)	284	(106)	3
8	TOT ADJUSTED SALE OF ELECTRICITY		ARTTP	1,145	184	381	619	9,534	19,743	86
9	OTHER OPERATING REVENUES		ROOT	4	1	18	2	295	709	1
10	TOTAL OPERATING REVENUES		ROTP	1,149	185	377	621	9,829	20,452	87
OPERATING EXPENSES										
OPERATING AND MAINTENANCE EXPENSES										
11	TRANSMISSION		EE20	0	0	0	0	0	0	0
12	DISTRIBUTION		EE30	48	9	24	20	2,016	6,608	12
13	OTHER OPER & MAINT EXPENSES		EE0T	473	54	77	32	1,533	3,281	4
14	TOTAL OPER & MAINT EXPENSES		EE00	521	63	101	52	3,549	11,889	16
DEPRECIATION EXPENSE										
15	TRANSMISSION		ED20	0	0	0	0	0	0	0
16	DISTRIBUTION		ED30	31	6	3	12	1,241	5,414	8
17	OTHER DEPRECIATION EXPENSE		ED0T	3	0	6	2	200	567	0
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE		ED00	34	6	9	14	1,441	5,981	8
TAXES										
19	CAPITAL STOCK PROP LEVEL		ET1P	2	0	3	1	87	182	0
20	OTHER-W/O CAP STOCK		ET001	2	0	5	0	141	318	0
21	DEFERRED INCOME TAXES		TXTA	18	2	24	3	497	1,320	2
22	NET INVESTMENT TAX CREDIT		TX93	0	0	(2)	0	(32)	(77)	0
23	GROSS RECEIPTS TAX		TXG	68	11	21	37	563	1,185	5
24	TOTAL PA INCOME TAX		TSIT1	48	10	21	51	279	(142)	5
25	TOTAL FED INC TAX		TFTX	141	30	63	156	483	(2,004)	13
26	TOTAL TAXES		TFIT1	279	53	134	248	2,005	729	25
27	TOTAL OPERATING EXPENSES		TEXP1	834	122	244	314	6,995	16,699	49
28	RETURN (LN 11 - 36)		PRRTN	315	63	133	307	2,634	1,653	36
29	TOTAL RATE BASE		RBX	686	138	950	271	30,655	63,676	16*
30	RATE OF RETURN (LN 47 / LN 48)		PRRTR	45.99%	45.85%	14.00%	113.28%	9.18%	2.91%	
31	CLASS RATE IN % OF TOTAL		PRCLRT	622.61%	518.75%	159.08%	1287.27%	104.32%	33.07%	

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2003
COMPONENTS OF OPERATING EXPENSES WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
\$1,000

Line No.	Input	Alloc P21	Output	Pa Jurisdct Distribution Only oca 11 6/02 HTY123103	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
OPERATING REVENUES AT PRESENT RATE LEVELS											
SALES OF ELECTRICITY											
1	TRANSMISSION REVENUES	TREV		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES	DREV		477,098	288,095	3,350	56,887	78,217	21,377	1,829	1,876
3	STATE TAX ADJ SURCHARGE	STAS		0	0	0	0	0	0	0	0
4	TOTAL SALE OF ELECTRICITY		RRT	477,098	288,095	3,350	56,887	78,217	21,377	1,829	1,876
5	LATE PAY CHARGES PRESENT RATES	S11 RCW4	R11	7,572	4,483	42	1,278	1,282	349	8	0
6	TOTAL ADJUSTED SALES OF ELECTRICITY		RRTT	484,670	292,578	3,392	57,965	79,509	21,726	1,837	1,876
7	ANNUALIZATION PRESENT REVENUES		ANN	5,884	5,170	35	785	641	153	(77)	(6)
8	ANNUAL ADJD SALE OF ELECT		ARTT	490,584	297,748	3,427	58,730	80,050	21,879	1,560	1,870
9	OTHER OPERATING REVENUES		ROOT	21,288	11,923	517	1,720	4,913	910	81	17
	TOTAL OPERATING REVENUES		ROT	511,850	309,671	3,944	60,450	84,983	22,789	1,621	1,887
OPERATING EXPENSES											
OPERATING AND MAINTENENCE EXPENSES											
10	TRANSMISSION		EE20	0	0	0	0	0	0	0	0
11	DISTRIBUTION		EE30	122,840	87,555	2,920	9,728	26,860	5,300	350	147
12	OTHER OPER & MAINT EXPENSES		EEOT	195,833	137,916	3,153	14,752	28,608	4,558	492	588
13	TOTAL OPER & MAINT EXPENSES		EE00	318,673	205,471	6,073	24,480	53,388	9,858	842	735
DEPRECIATION EXPENSE											
14	TRANSMISSION		ED20	0	0	0	0	0	0	0	0
15	DISTRIBUTION		ED30	73,522	40,859	1,727	5,888	16,779	2,479	163	86
16	OTHER DEPREC EXP		EDOT	15,703	9,948	328	1,368	2,752	488	31	11
	TOTAL DEPRECIATION AND										
17	AMORTIZATION EXPENSE		ED00	89,225	50,805	2,053	7,248	18,531	2,947	194	97
TAXES											
18	CAPITAL STOCK PRESENT LEVEL		ET1	8,220	4,873	202	870	1,876	330	22	9
19	OTHER W/D CAP STOCK		ET001	8,597	5,444	182	743	1,548	272	17	7
20	DEFERRED INCOME TAXES		TXTA	24,873	13,785	610	2,028	5,805	996	63	21
21	NET INVESTMENT TAX CREDIT		TXB3	(1,924)	(1,073)	(47)	(155)	(448)	(92)	(5)	(2)
22	GROSS RECEIPTS TAX		TXG	28,943	17,587	202	3,485	4,723	1,291	92	110
23	TOTAL PA INCOME TAX		TSIT1	(4,820)	(3,587)	(731)	1,509	(1,858)	385	18	83
24	TOTAL FED INC TAX		TFTX	(32,703)	(21,004)	(2,717)	3,380	(9,888)	499	9	243
25	TOTAL TAXES		TFIT1	30,575	15,481	(2,314)	11,571	1,839	3,645	212	470
26	TOTAL OPERATING EXPENSES		TEXP1	438,473	271,857	5,812	43,297	73,738	18,460	1,248	1,302
	RETURN (LN 11 - 36)		PRERTN	73,377	37,814	(1,868)	17,153	11,225	6,339	373	585
27	TOTAL RATE BASE		RBX	1,814,993	1,031,108	44,988	148,992	415,334	72,547	4,810	2,061
	RATE OF RETURN (LN 47 / LN 48)		PRRTR	4.04%	3.67%	-4.15%	11.67%	2.70%	8.74%	7.75%	28.38%
	CLASS RATE IN % OF TOTAL		PRCLR1	100.00%	90.84%	-102.72%	288.86%	68.83%	216.34%	191.83%	702.48%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2003
COMPONENTS OF OPERATING EXPENSES WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
\$1,000

Line No.	Input	Alloc P21	Output	IST	LP-8	LPEP	ISA	GH	SL/AL	L5-S
OPERATING REVENUES AT PRESENT RATE LEVELS										
SALES OF ELECTRICITY										
1	TRANSMISSION REVENUES	TREV		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES	DREV		1,888	243	371	680	4,924	17,755	28
3	STATE TAX ADJ SURCHARGE	STAS		0	0	0	0	0	0	0
4	TOTAL SALE OF ELECTRICITY		RRT	1,888	243	371	680	4,924	17,755	28
5	LATE PAY CHARGES PRESENT RATES	S11 RCW4	R11	0	0	0	0	87	52	1
6	TOTAL ADJUSTED SALES OF ELECTRICITY		RRTT	1,888	243	371	680	4,991	17,807	29
7	ANNUALIZATION PRESENT REVENUES		ANN	(140)	54	(43)	(97)	(238)	(224)	(1)
8	ANNUAL ADJD SALE OF ELECT		ARTT	1,748	297	328	583	4,755	17,583	0
9	OTHER OPERATING REVENUES		ROOT	8	1	19	2	352	844	1
	TOTAL OPERATING REVENUES		ROT	1,752	298	347	585	5,107	18,427	1
OPERATING EXPENSES										
OPERATING AND MAINTENANCE EXPENSES										
10	TRANSMISSION		EE20	0	0	0	0	0	0	0
11	DISTRIBUTION		EE30	51	10	23	20	1,981	7,887	12
12	OTHER OPER & MAINT EXPENSES		EE0T	504	48	88	35	1,920	5,267	8
13	TOTAL OPER & MAINT EXPENSES		EE00	555	58	111	55	3,901	13,154	20
DEPRECIATION EXPENSE										
14	TRANSMISSION		ED20	0	0	0	0	0	0	0
15	DISTRIBUTION		ED30	30	6	3	12	1,184	6,217	7
16	OTHER DEPREC EXP		ED0T	3	0	7	1	205	597	0
TOTAL DEPRECIATION AND AMORTIZATION EXPENSE										
17			ED00	33	6	10	13	1,389	5,814	7
TAXES										
18	CAPITAL STOCK PRESENT LEVEL		ET1	3	1	5	1	137	291	1
19	OTHER-W/O CAP STOCK		ET001	1	0	4	0	114	282	0
20	DEFERRED INCOME TAXES		TXTA	5	2	21	2	418	1,111	2
21	NET INVESTMENT TAX CREDIT		TX83	(1)	0	(2)	0	(32)	(77)	0
22	GROSS RECEIPTS TAX		TXG	103	18	19	33	281	1,037	2
23	TOTAL PA INCOME TAX		TSIT1	103	21	14	45	(241)	(584)	(1)
24	TOTAL FED INC TAX		TFTX	317	65	44	138	(1,038)	(2,955)	(4)
25	TOTAL TAXES		TFIT1	631	107	105	220	(371)	(935)	0
26	TOTAL OPERATING EXPENSES		TEXP1	1,119	171	226	288	4,899	18,033	27
RETURN (LN 11 - 36)										
			PRERT1	633	127	121	277	208	394	(28)
27	TOTAL RATE BASE		RBX	727	147	982	288	30,517	84,370	173
RATE OF RETURN (LN 47 / LN 48)										
			PRRTR	87.07%	88.39%	12.32%	98.18%	0.68%	0.61%	-15.03%
CLASS RATE IN % OF TOTAL										
			PRCLRT	2155.20%	2138.37%	304.95%	2380.69%	18.83%	16.10%	-372

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2003
OPERATING REVENUES AT PROPOSED RATE LEVELS
\$1,000

Line No.	Input	Alloc P23	Output	Pa Jurisdct Distribution Only oca 11 6/02 HTY123103	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-6
OPERATING REVENUES AT PROPOSED RATE LEVELS											
SALES OF ELECTRICITY											
1	TRANSMISSION REVENUES	TREVP		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES	DREVP		627,627	389,204	3,887	77,147	114,716	29,724	1,999	1,502
3	STATE TAX ADJ SURCHARGE	STAS		0	0	0	0	0	0	0	0
4	TOTAL SALE OF ELECTRICITY		RRTP	627,627	389,204	3,887	77,147	114,716	29,724	1,999	1,502
5	LATE PAY CHARGES PROPOSED		R11P	8,302	4,916	46	1,402	1,418	382	10	0
6	TOT ADJUSTED SALE OF ELECTRICITY		RRTP	635,929	374,120	3,933	78,549	116,131	30,108	2,009	1,502
7	ANNUALIZATION PROPOSED REVS		ANNP	7,924	6,709	41	1,056	798	203	(95)	(4)
8	TOT ADJUSTED SALE OF ELECTRICITY		ARTTP	643,753	380,829	3,974	79,605	116,929	30,309	1,914	1,498
9	OTHER OPERATING REVENUES		ROOT	21,266	11,887	518	1,715	4,938	816	81	17
10	TOTAL OPERATING REVENUES		ROTP	665,039	392,716	4,492	81,320	121,867	31,224	1,975	1,515
OPERATING EXPENSES											
OPERATING AND MAINTENANCE EXPENSES											
11	TRANSMISSION		EE20	0	0	0	0	0	0	0	0
12	DISTRIBUTION		EE30	122,840	87,555	2,920	9,728	26,880	5,300	350	147
13	OTHER OPER & MAINT EXPENSES		EE0T	195,833	137,916	3,153	14,752	26,508	4,558	492	588
14	TOTAL OPER & MAINT EXPENSES		EE00	318,673	205,471	6,073	24,480	53,388	9,858	842	735
DEPRECIATION EXPENSE											
15	TRANSMISSION		ED20	0	0	0	0	0	0	0	0
16	DISTRIBUTION		ED30	73,522	46,959	1,727	5,888	15,779	2,479	183	86
17	OTHER DEPRECIATION EXPENSE		ED0T	15,703	9,946	328	1,359	2,752	488	31	11
18	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE		ED00	89,225	56,905	2,055	7,246	18,531	2,947	194	97
TAXES											
19	CAPITAL STOCK PROP LEVEL		ET1P	8,220	4,673	202	670	1,676	330	22	9
20	OTHER-W/O CAP STOCK		ET001	8,597	5,444	182	743	1,548	272	17	7
21	DEFERRED INCOME TAXES		TXTA	24,873	13,785	610	2,028	5,805	998	63	21
22	NET INVESTMENT TAX CREDIT		TXB3	(1,924)	(1,073)	(47)	(185)	(448)	(82)	(5)	(2)
23	GROSS RECEIPTS TAX		TXG	37,981	22,469	234	4,697	8,899	1,768	113	88
24	TOTAL PA INCOME TAX		TSIT1	9,519	4,205	(681)	3,466	1,599	1,158	49	48
25	TOTAL FED INC TAX		TFTX	12,518	3,508	(2,559)	9,531	1,230	2,991	113	133
26	TOTAL TAXES		TFIT1	99,784	53,009	(2,059)	20,980	18,507	7,451	372	304
27	TOTAL OPERATING EXPENSES		TEXP1	507,882	309,385	6,067	52,708	90,406	20,258	1,408	1,138
28	RETURN (LN 11 - 36)		PRERTN	157,357	83,331	(1,575)	28,614	31,461	10,968	587	379
29	TOTAL RATE BASE		RBX	1,814,993	1,031,108	44,988	146,992	415,334	72,547	4,810	2,061
30	RATE OF RETURN (LN 47 / LN 48)		PRRTR	8.67%	8.08%	-3.50%	19.47%	7.57%	15.12%	11.79%	18.38%
31	CLASS RATE IN % OF TOTAL		PRCLRT	100.00%	93.19%	-40.37%	224.57%	87.31%	174.36%	135.99%	212.11%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2003
OPERATING REVENUES AT PROPOSED RATE LEVELS
\$1,000

Line No.	Input	Alloc P23	Output	IST	LP-6	LPEP	ISA	GH	SL/AL	L6-S
OPERATING REVENUES AT PROPOSED RATE LEVELS										
SALES OF ELECTRICITY										
1	TRANSMISSION REVENUES	TREVP		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES	DREVP		1,355	167	483	661	6,778	19,864	61
3	STATE TAX ADJ SURCHARGE	STAS		0	0	0	0	0	0	0
4	TOTAL SALE OF ELECTRICITY		RRTP	1,355	167	483	661	6,778	19,864	61
6	LATE PAY CHARGES PROPOSED		R11P	0	0	0	0	73	57	0
8	TOT ADJUSTED SALE OF ELECTRICITY		RRTTP	1,355	167	483	661	6,851	19,921	61
7	ANNUALIZATION PROPOSED REVS		ANNP	(98)	38	(55)	(98)	(316)	(256)	(1)
8	TOT ADJUSTED SALE OF ELECTRICITY		ARTTP	1,259	205	408	563	6,535	19,665	60
9	OTHER OPERATING REVENUES		ROOT	6	1	19	2	354	849	1
10	TOTAL OPERATING REVENUES		ROTP	1,265	206	427	565	6,889	20,514	61
OPERATING EXPENSES										
OPERATING AND MAINTENANCE EXPENSES										
11	TRANSMISSION		EE20	0	0	0	0	0	0	0
12	DISTRIBUTION		EE30	51	10	23	20	1,981	7,887	12
13	OTHER OPER & MAINT EXPENSES		EE0T	504	48	88	35	1,920	5,267	8
14	TOTAL OPER & MAINT EXPENSES		EE00	555	58	111	55	3,901	13,154	20
DEPRECIATION EXPENSE										
15	TRANSMISSION		ED20	0	0	0	0	0	0	0
16	DISTRIBUTION		ED30	30	8	3	12	1,164	5,217	7
17	OTHER DEPRECIATION EXPENSE		ED0T	3	0	7	1	205	597	0
TOTAL DEPRECIATION AND AMORTIZATION EXPENSE										
18			ED00	33	8	10	13	1,369	6,814	7
TAXES										
19	CAPITAL STOCK PROP LEVEL		ET1P	3	1	5	1	137	291	1
20	OTHER-W/O CAP STOCK		ET001	1	0	4	0	114	262	0
21	DEFERRED INCOME TAXES		TXTA	5	2	21	2	418	1,111	2
22	NET INVESTMENT TAX CREDIT		TX93	(1)	0	(2)	0	(32)	(77)	0
23	GROSS RECEIPTS TAX		TXG	74	12	24	33	388	1,160	4
24	TOTAL PA INCOME TAX		TSIT1	57	12	22	45	(74)	(388)	2
25	TOTAL FED INC TAX		TFTX	173	38	68	138	(513)	(2,343)	8
26	TOTAL TAXES		TFIT1	312	65	142	220	438	15	15
27	TOTAL OPERATING EXPENSES		TEXP1	900	128	283	288	5,706	18,983	42
28	RETURN (LN 11 - 36)		PRERTN	365	77	164	277	1,183	1,531	19
29	TOTAL RATE BASE		RBX	727	147	982	288	30,517	64,370	173
30	RATE OF RETURN (LN 47 / LN 48)		PRRTR	50.21%	62.38%	16.70%	96.18%	3.88%	2.38%	10.7
31	CLASS RATE IN % OF TOTAL		PRCLRT	579.12%	804.15%	192.62%	1109.34%	44.75%	27.45%	

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Schedule RAG-2

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

PPL Electric Utilities Corporation
Cost of Service Study Results

DOCUMENT

	Total PA Jurisdiction		Residential RS per OCA		Residential RS per PPL	
	Rate of Return	Index Return	Rate of Return	Index Return	Rate of Return	Index Return
Historic test year Present Rates	4.04%	[100%]	3.67%	[90.84%]	1.87%	[46.29%]
Historic test year Proposed Rates	8.67%	[100%]	8.08%	[93.19%]	5.58%	[14.36%]
Future test year Present Rates	3.91%	[100%]	2.92%	[74.68%]	1.60%	[40.92%]
Future test year Proposed Rates	8.80%	[100%]	7.21%	[81.93%]	5.29%	[60.11%]

FUTURE TEST YEAR COST ALLOCATION
COMPANY AND PPLC ADJUSTMENTS FOR COMPLIANCE FILING

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
COMPONENTS OF OPERATING EXPENSES AT APPROVED RATE LEVELS
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
PPLC JURISDICTIONAL COST ALLOCATION \$1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK DEMAND RESPONSIBILITY

PART 3
SUMMARY

	INPUT	ALLOC	OUTPUT	TOTAL PENNA. JURISDICT	RS	RTS	GS-1	GS-3	LP-4
1	OPERATING REVENUES AT APPROVED RATE LEVELS								
2	SALE OF ELECTRICITY								
3	RATE REVENUE APPROVED	RRP		2,348,853	953,918	21,492	168,178	531,689	269,460
4	ENERGY REVENUE APPROVED	ECRP		25	1,399	50	115	514	-531
5	STATE TAX ADJ SURCHARGE	STASP		0	0	0	0	0	0
6	SPEC BASE RATE CREDIT ADJ	SBRCAP		-39,498	-15,835	-157	-2,791	-8,880	-4,694
7	TOTAL SALE OF ELECTRICITY		RRTP	2,309,380	939,482	21,185	165,502	523,323	264,235
8	ANNUALIZATION	ANRP		-26,556	8,493	380	3,518	5,536	4,919
9	LATE PAY CHARGES	SLIP	CM4	7,341	3,641	28	1,363	1,586	191
10	TOT ADJ'D SALE OF ELECTRIC		RRTP	2,343,277	951,616	21,593	170,183	530,445	269,545
11	OTHER OPERATING REVENUES		ROOT	165,535	42,811	1,383	6,805	23,217	13,886
12	TOTAL OPERATING REVENUES		ROUTP	2,508,812	994,427	22,976	176,988	553,662	283,431
13	OPERATING EXPENSES								
14	OPERATING AND MAINTENANCE EXPENSES								
15	PRODUCTION								
16	FUEL		EOPF1	431,704	153,338	5,471	21,424	94,542	56,935
17	POWER PURCHASES		EOPP1	252,512	89,959	3,252	12,539	55,412	33,177
18	OTHER PRODUCTION		EOPD1	297,079	110,334	4,707	14,881	66,888	36,944
19	TOTAL PRODUCTION		EE10T	981,295	353,631	13,430	48,844	216,862	127,055
20	O & M TRANSMISSION		EE20	10,487	4,025	192	529	2,411	1,000
21	O & M DISTRIBUTION		EE30	92,936	51,714	2,093	7,737	15,501	5,888
22	OTHER OPER & MAINT EXP		EOMT1	224,529	131,620	3,364	15,862	31,831	16,510
23	TOTAL OPER & MAINT EXPENSES		EE00T	1,309,246	540,990	19,079	72,972	266,605	148,353
24	DEPRECIATION EXPENSE								
25	PRODUCTION								
26	TRANSMISSION		ED10	231,599	88,905	4,233	11,683	53,235	27,277
27	DISTRIBUTION		ED20	7,753	2,988	142	393	1,789	866
28	GENERAL		ED30	70,147	41,443	1,514	5,654	10,577	5,666
29	TOTAL DEPRECIATION EXPENSE		ED00	309,499	133,336	5,889	17,730	65,491	33,749
30	AMORTIZATION EXP (ACCT 406)		ED05T	320,797	138,938	6,093	18,444	67,685	33,888
31	TOTAL DEPRECIATION AND		ED97T	0	0	0	0	0	0
32	AMORTIZATION EXPENSE		E000	305,523	133,074	5,814	17,673	64,175	33,888
33	MISC ALLOWABLE EXPENSES								
34	TAXES								
35	INCREASE CAPITAL STOCK		ET11	31,238	13,905	606	1,841	6,550	3,059
36	-OTHER M/O CAP STOCK		ET001	57,584	26,400	1,072	3,444	11,591	5,507
37	DEFERRED INCOME TAXES		TMT	-10,078	-1,179	-121	-149	-3,168	-2,125
38	NET INV TAX CR		TX91	-8,625	-3,876	-167	-513	-1,788	-830
39	GROSS RECEIPTS TAX		TXSRP	103,104	41,872	950	7,497	23,339	11,860
40	STATE INCOME TAX		TSXMP	71,450	21,772	-658	7,425	19,332	9,305
41	FEDERAL INCOME TAX		TFXMP	200,344	60,716	-1,907	20,917	54,350	26,160
42	TOTAL TAXES		TEN1	445,817	159,609	-225	40,482	130,206	52,944
43	TOTAL OPERATING EXP		TENP1	2,030,112	822,297	24,127	129,631	434,170	228,680
44	RETURN (LN 12 - 42)		PRERTN	478,700	172,130	-1,151	46,757	119,492	54,751
45	TOTAL RATE BASE		RBX	5,017,700	2,251,525	97,298	298,179	1,044,620	485,782
46	RATE OF RETURN (LN 43 / RBX)		PRRTRP	9.54	7.65	-1.18	15.68	11.44	11.27
47	CLASS RATE IN % OF TOTAL		PRCLRT	100.0	80.1	-12.4	164.4	119.9	118.1

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 STATE OF PENNSYLVANIA
 BUREAU OF TRANSPORTATION

AUG 17 2004

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FUTURE TEST YEAR COST ALLOCATION
COMPANY AND PPUC ADJUSTMENTS FOR COMPLIANCE FILING

PENNSYLVANIA POWER & LIGHT COMPANY
COST ALLOCATION DETAILS - FUTURE TEST YEAR ENDED 9/30/95
COMPONENTS OF OPERATING EXPENSES AT APPROVED RATE LEVELS
WITH RESULTING RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
PPUC JURISDICTIONAL COST ALLOCATION \$1,000
CAPACITY ALLOCATION METHOD-MONTHLY PEAK DEMAND RESPONSIBILITY

PART 3
SUMMARY

	INPUT	ALLOC	OUTPUT	LSP	LP-5,6	1ST	LPEP	ISA	STANDBY	
1	OPERATING REVENUES AT APPROVED RATE LEVELS									
2	SALE OF ELECTRICITY									
3	RATE REVENUE APPROVED			RRP	21,274	179,975	102,067	8,824	20,991	1,196
4	ENERGY REVENUE APPROVED			ECRP	-54	-770	-579	-36	-131	-3
5	STATE TAX ADJ SURCHARGE			STASP	0	0	0	0	0	0
6	SPEC BASE RATE CREDIT ADJ			SORCAP	-153	-3,206	-1,694	-146	-363	-20
7	TOTAL SALE OF ELECTRICITY			RRTP	20,867	175,999	99,794	8,642	20,497	1,173
8	ANNUALIZATION			ANNP	0	5,156	0	0	0	0
9	LATE PAY CHARGES			SLIP CMG	0	138	0	0	0	0
10	TOT ADJ'D SALE OF ELECTRIC			RRTP	20,867	181,293	99,794	8,642	20,497	1,173
11	OTHER OPERATING REVENUES			ROOT	6,374	10,519	43,960	459	13,915	35
12	TOTAL OPERATING REVENUES			ROTP	27,241	191,812	143,754	9,101	34,412	1,208
13	OPERATING EXPENSES									
14	OPERATING AND MAINTENANCE EXPENSES									
15	PRODUCTION									
16	FUEL			EOPF1	5,709	44,048	31,792	1,972	7,158	154
17	POWER PURCHASES			EOPP1	3,325	25,665	18,427	1,153	4,147	90
18	OTHER PRODUCTION			EOP01	3,667	28,039	18,879	1,325	4,233	112
19	TOTAL PRODUCTION			EE10T	12,701	97,802	69,098	4,450	15,538	356
20	O & M TRANSMISSION			EE20	122	927	585	46	131	4
21	O & M DISTRIBUTION			EE30	447	1,583	786	84	238	6
22	OTHER OPER & MAINT EXP			EOMT1	1,482	10,700	7,192	511	1,591	43
23	TOTAL OPER & MAINT EXPENSES			EE00T	14,752	111,012	77,659	5,091	17,478	409
24	DEPRECIATION EXPENSE									
25	PRODUCTION			EO10	2,704	20,475	12,918	1,011	2,682	92
26	TRANSMISSION			EO20	91	688	434	27	75	3
27	DISTRIBUTION			EO30	282	909	505	47	126	4
28	GENERAL			ED80	97	685	430	34	97	3
29	TOTAL DEPRECIATION EXPENSE			EDDST	3,174	22,757	14,287	1,119	3,180	102
30	AMORTIZATION EXP (ACCT 406)			ED97T	0	0	0	0	0	0
31	TOTAL DEPRECIATION AND									
32	AMORTIZATION EXPENSE			EO00	2,996	21,406	13,435	1,052	2,990	96
33	MISC ALLOWABLE EXPENSES			TX89	-346	-2,630	-1,664	-130	-370	-11
34	TAXES									
35	INCREASE CAPITAL STOCK			EY11	300	2,065	1,295	101	288	9
36	-OTHER N/D CAP STOCK			EY001	543	3,764	2,400	184	533	15
37	DEFERRED INCOME TAXES			TMT	-210	-1,880	-1,227	-94	-277	-8
38	NET INV TAX CR			TX91	-82	-557	-350	-28	-77	-2
39	GROSS RECEIPTS TAX			TXGRP	919	7,976	4,391	381	992	51
40	STATE INCOME TAX			TSTXP	862	5,322	5,131	267	1,598	70
41	FEDERAL INCOME TAX			TFTXP	2,423	14,945	14,454	751	3,943	197
42	TOTAL TAXES			TEK1	4,754	31,637	26,095	1,562	6,710	333
43	TOTAL OPERATING EXP			TEXP1	22,156	161,425	115,525	7,575	26,808	827
44	RETURN (LN 12 - 42)			PRRTN	5,085	30,387	28,229	1,526	7,604	381
45	TOTAL RATE BASE			RBX	47,420	325,549	205,020	15,838	45,327	1,434
46	RATE OF RETURN (LN 43 / RBX)			PRRTRP	10.68	9.33	13.77	9.64	16.78	26.57
47	CLASS RATE IN % OF TOTAL			PRCLRT	111.9	97.8	144.3	101.0	175.8	278.5

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Schedule RAG-4

PA PUBLIC UTILITY COMMISSION
 PPL Electric Utilities Corporation BUREAU
 Distribution (Customer) Charge Determination
 Residential RS
 \$000's

Electric Plant

Cost

Services
Meters

DOCUMENT

\$387,286
175,573

\$562,859

Depreciation Reserve

Services
Meter

\$201,159
31,774

\$232,933

Net Customer Plant

\$329,926

Pre-tax rate of return

12.7%

Return & taxes

\$41,900

Depreciation Expense/Services

10,055

Depreciation Expense/Meters

6,276

DOCKETED

AUG 18 2004

O&M

Services

5,247

Meters

8,434

Meter Reading

9,028

Collection Expense

5,327

Other Customer Accts Exp

17,359

Employee Benefits @ 10% of O&M

4,540

Total Cost

\$108,166

Customer Bills (12 x 1,151,910)

\$7.83/Cust/mo.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC
UTILITY COMMISSION

)
)
)
)

DOCKET NO. R-00049255


v.

PPL ELECTRIC UTILITIES
CORPORATION

)
)

AFFIDAVIT

Richard A. Galligan being first duly sworn, deposes and says that he is the same Richard A. Galligan whose Direct Testimony accompanies this affidavit: that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn testimony in this proceeding.


Richard A. Galligan

Subscribed and sworn before me on this 10 day of August, 2004.


Notary Public

My Commission Expires: 2/2007

872-2475
HRB

DOCUMENT BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)
UTILITY COMMISSION)
v.)
PPL ELECTRIC UTILITIES)
CORPORATION)

DOCKET NO. R-00049255

REBUTTAL TESTIMONY

OF

RICHARD A. GALLIGAN

DOCKETED

AUG 18 2004

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JULY 2004

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EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)	
UTILITY COMMISSION)	
)	
v.)	DOCKET NO. R-00049255
)	
PPL ELECTRIC UTILITIES)	
CORPORATION)	

REBUTTAL TESTIMONY OF RICHARD A. GALLIGAN

- 1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.
- 2 A. My name is Richard A. Galligan. I am a Principal with Exeter Associates, Inc., a firm of
3 consulting economists specializing in utility economics. My business address is 5565
4 Sterrett Place, Suite 310, Columbia, Maryland 21044.
- 5 Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THESE PROCEEDINGS?
- 6 A. Yes. My direct testimony was filed as OCA Statement No. 4.
- 7 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?
- 8 A. The purpose of my rebuttal testimony is to respond to the direct testimony of Messrs.
9 Robert D. Knecht and Mark D. Ewen on behalf of the Office of Small Business Advocate;
10 James T. Selecky on behalf of Pennsylvania Energy Consortium and Wal-Mart Stores
11 East, LP; Stephen J. Baron on behalf of PPL Industrial Customer Alliance; and Kenneth L.
12 Kincl on behalf of the Department of Defense/Federal Executive Agencies, as their
13 testimony relates to PPL Electric Utilities Corporation's ("PPL" or the "Company") class
14 cost of service study and the spread of any rate increase among the customer classes.

1 Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE ACCEPTANCE OF
2 PPL'S CLASS COST OF SERVICE STUDY RESULTS BY PARTICIPANTS TO
3 THESE PROCEEDINGS.

4 A. Mr. Knecht/Ewen critique several aspects of PPL's cost studies, but in the final analysis,
5 they accept the study results and use those results when they address what they believe is
6 an unfair distribution of PPL's proposed revenue increase. At page 9 of Mr.
7 Knecht/Ewen's direct testimony, in answer to the question, "Have you made any
8 modifications to PPL's cost of service study to properly reflect cost causation," Mr.
9 Knecht/Ewen answer "No.," and they continue on to alert the Commission to a cost
10 functionalization concern the Commission may have to deal with in the future. At page 13
11 of their direct testimony, Mr. Knecht/Ewen indicate there were programming errors in
12 PPL's cost study, but they conclude that they believe their own study results "are very
13 similar to the overall results produced by PPL's corrected version." Still at page 13 and
14 page 14 of their direct testimony, in answer to the questions, "How do the results of your
15 adjusted PPL cost of service study compare with PPL's filed analysis?" Mr. Knecht/Ewen
16 answer that "the results from the adjustment vary modestly, though they do not change any
17 of the basic conclusions from the study regarding cost over- and under-recovery." Mr.
18 Knecht/Ewen then describe the resulting differences, concluding that "the GS-1 class
19 impact is *de minimus*," and include a table comparing their adjusted study results to PPL's
20 filed cost study results. Finally, to demonstrate the alleged unfairness in PPL's proposed
21 rate spread, Mr. Knecht/Ewen utilize at page 24 of their direct testimony PPL's cost
22 studies at *present and proposed rates*.

23 Mr. Selecky, at page 2 of his direct testimony concludes and recommends that,
24 "The Commission should utilize the results of PPL Electric's distribution cost of service

1 study for purposes of allocating any approved increase in this case.” Mr. Kinzel states at
2 page 5 of his direct testimony that, “Regarding cost allocation, I generally support the
3 distribution cost of service study performed by the Company, but call for a significant
4 change in the Company’s customer class allocation of necessary increases in total revenue
5 requirements.” Mr. Baron states at page 33 of his direct testimony that, “In general, I do
6 not have objections to the Company’s filed cost of service study and believe that it is a
7 reasonable basis upon which to make a determination of the appropriate allocation of any
8 Commission authorized increase in distribution revenue requirements.”

9 Q. DOES THE ACCEPTANCE OF PPL’S COST OF SERVICE STUDIES BY
10 SOME PARTICIPANTS IN THESE PROCEEDINGS CURE THE ILLS
11 CONTAINED IN THE COMPANY’S STUDY THAT YOU DISCUSSED IN
12 YOUR DIRECT TESTIMONY?

13 A. No. Simply because some parties express a preference for PPL’s cost study variant does
14 not validate that study or cure its ills. For example, in my direct testimony I discuss that
15 PPL included substantial capacity-related, or demand-related costs, in its customer related
16 cost determinations. This error in PPL’s study is then compounded by the allocation of
17 these demand-related costs on a customer-count basis instead of on the basis of allocation
18 factors that are derived from customer demands. Parties who accept PPL’s studies do not
19 correct these erroneous classifications and allocations included in the PPL’s studies being
20 accepted.

21 I also discuss in my direct testimony that PPL did not recognize the significant
22 demands that can be met with its minimum system plant configuration that it proposes as
23 the customer component of service when it reaches the step of allocating its demand-
24 related costs. Because PPL did not recognize that all or a portion of its customers’

1 demands can be provided for with the demand carrying capacity of its proposed minimum
2 system plant configuration, customer demands are double-counted, being provided for
3 once with the minimum system costs allocated on a customer-count basis, and being
4 provided for once again in PPL's allocation of its demand-related costs. This double-count
5 is particularly detrimental to smaller customers not only because there is significant
6 demand serving capability in PPL's proposed minimum system, but also because the
7 demand serving capability in the minimum system represents all, or a larger portion of
8 smaller customer demands compared to customers with larger demand requirements. No
9 party has cured the improper double-count, and unreasonable allocation of demand-related
10 costs included in the Company's study. Mr. Knecht/Ewen address this double-count
11 aspect in PPL's cost of service studies. I will discuss this aspect of Mr. Knecht/Ewen's
12 direct testimony later in this rebuttal testimony.

13 The third major problem with PPL's cost studies that I addressed in my direct
14 testimony relates to PPL's allocation of virtually all of its distribution costs on a customer
15 and peak demand basis only. Cost allocations should reflect cost causality. In my direct
16 testimony, I pointed out that PPL's *raison d'etre* is that its customers have demands for
17 electricity throughout the year, those demands being higher at some times during the year.
18 Ironically, while it is sustained demands throughout the year on which the very existence
19 of PPL delivery service depends, PPL allocates none of its distribution costs on the basis of
20 sustained energy demands, and Messrs. Knecht, Kincel, Baron and Selecky all adopt the
21 PPL results. Participants' acceptance of PPL's study does not change the fact that while a
22 cost of service study is supposed to allocate costs on the basis of cost causality, PPL's
23 study allocates no costs on the basis of the very energy demands that are absolutely
24 essential to the Company's existence.

1 Q. YOU MENTIONED THAT MR. KNECHT/EWEN ADDRESS THE FACT THAT
2 THE MINIMUM SYSTEM APPROACH ASSIGNS TOO MUCH DEMAND-
3 RELATED COSTS TO THE CUSTOMER COSTS CATEGORY. PLEASE
4 DISCUSS YOUR UNDERSTANDING OF THIS ASPECT OF MR.
5 KNECHT/EWEN'S TESTIMONY.

6 A. Mr. Knecht/Ewen discuss determination of customer costs at pages 15-17 of their direct
7 testimony. Mr. Knecht/Ewen discuss the minimum system method for determining
8 customer costs and the fact that the minimum system overstates customer costs. Mr.
9 Knecht/Ewen then explain that the zero-intercept method can be used to calculate an
10 estimate of the cost of distribution assets that would have no load-carrying capability, and
11 hence, be unable to meet any customer demands.

12 Mr. Knecht/Ewen testify at page 15, line 29-page 16, line 3:

13
14 However, the primary conceptual problem with the minimum system
15 approach is that the minimum system often has load-carrying
16 capability and it therefore includes demand-related costs. Some
17 experts attempt to recognize this load-carrying capability with an
18 adjustment in the cost allocation stage, by deducting the load-
19 carrying capability of the minimum system from the demand cost
20 allocations.

21
22 Of course, in this case PPL has not attempted to either remove the demand-related,
23 load-carrying capability costs from its proposed customer costs or attempted to
24 adjust class demand allocators for the demands already included in its proposed
25 customer cost determinations.

26 Further recognizing the overstatement of PPL's proposed customer costs,

27 Mr. Knecht/Ewen testify at page 16, lines 19-21:

1 As detailed above, the unadjusted *minimum* method is inaccurate
2 because it overstates the customer component of costs, since the
3 minimum system includes some load carrying capability.
4

5 My understanding of Mr. Knecht/Ewen's testimony is that they agree that the
6 minimum system method, the method employed by PPL in this case, overstates
7 customer costs and misallocates these overstated costs on a customer rather than on
8 a demand basis.

9 Q. DO MR. KNECHT/EWEN DISCUSS ANOTHER METHOD OF
10 DETERMINING CUSTOMER COSTS THAT WOULD AVOID THE
11 OVERSTATEMENT OF CUSTOMER COSTS THAT THEY DESCRIBE IN
12 THEIR DIRECT TESTIMONY?

13 A. Yes, at page 16, lines 4-6, Mr. Knecht/Ewen testify:

14
15 As an alternative approach to adjust for the load carrying capability
16 of the minimum system, some analysts use the "zero-intercept"
17 methodology, which uses a statistical calculation to estimate the cost
18 of a minimum system with zero load-carrying capability.
19

20 At page 16, lines 17-19, Mr. Knecht/Ewen testify:

21 Q. Of these two methods [minimum system method and zero-
22 intercept method], which do you believe is a more accurate
23 approach for estimating the customer component of distribution
24 costs?
25

26 A. The zero-intercept method.
27

28 Thus, Mr. Knecht/Ewen explain that the zero-intercept method seeks to address the
29 overstatement of customer costs inherent in the minimum system methodology by
30 statistical determinations that avoid the inclusion of any demand-related costs in the
31 customer cost category.

1 Q. HAVE MR. KNECHT/EWEN PERFORMED A ZERO-INTERCEPT
2 DETERMINATION OF CUSTOMER COSTS ON THE PPL SYSTEM?

3 A. No. After explaining that the zero-intercept method statistically attempts to determine
4 customer costs that contain no demand-related costs, Mr. Knecht/Ewen do not apply the
5 zero-intercept method to PPL costs. At OSBA Statement 1, page 17, lines 18-19, Mr.
6 Knecht/Ewen testify:

7
8 Q. Have you prepared a full zero-intercept analysis of PPL's
9 distribution system?

10
11 A. No.

12 Q. HOW THEN DID MR. KNECHT/EWEN ATTEMPT TO DETERMINE THE
13 CUSTOMER COST COMPONENT OF PPL'S COMMON DISTRIBUTION
14 PLANT THAT THEY PROPOSE?

15 A. Mr. Knecht/Ewen explain at pages 17-18 of their direct testimony that they determined the
16 customer related component of costs on the basis of what they describe variously as a
17 "judgmental classification approach," based on "very rough calculations of the zero-
18 intercept classification split for overhead conductors, underground conductors, poles and
19 transformers based on the cost of adding new facilities," and containing "judgmental
20 adjustments...based on the premise that the zero-intercept minimum system should have a
21 lower customer share of costs than the PPL minimum system approach." [emphasis
22 added] Having deduced that "...the zero-intercept unit costs should be lower than the
23 minimum system unit cost, and it should be above zero," Mr. Knecht/Ewen judgmentally
24 and using "very rough calculations" of new facilities costs arrived at their proposed
25 customer costs. In fact, Mr. Knecht/Ewen did not reduce PPL's minimum system
26 determinations for poles and underground conductors and conduit; they did reduce the

1 customer components of overhead conductors and transformers from 62.4 percent to 40
2 percent and from 69.9 percent to 50 percent, respectively.

3 Q. DO YOU ADVISE THE DETERMINATION OF RATES BASED ON
4 JUDGMENTAL AND VERY ROUGH CALCULATIONS PERFORMED ON
5 THE COST OF ADDING NEW FACILITIES?

6 A. No. Having recognized that PPL's minimum system cost studies overstate customer cost
7 determinations and misallocate the overstated costs on a customer-count basis, and
8 recognizing that the zero-intercept method conceptually attempts to avoid this
9 overstatement, it is not sufficient to judgmentally, and very roughly adjust some of the
10 minimum system component costs in an attempt to resuscitate PPL's flawed studies, and
11 the results those studies yield.

12 Q. ARE THERE PARTICULAR PROBLEMS ASSOCIATED WITH USING THE
13 COST OF ADDING NEW FACILITIES WHEN VERY ROUGHLY
14 CALCULATING ZERO-INTERCEPT COSTS?

15 A. Yes. Using the cost of new facilities to perform the zero-intercept calculations does not
16 conform to the zero-intercept method described in the NARUC Cost Allocation Manual.
17 Mr. Knecht/Ewen reference that Manual at page 16, lines 15-16 of their direct testimony.
18 However, the zero-intercept method contained in the NARUC Cost Allocation Manual
19 clearly requires the zero-intercept customer cost methodology to be based on book costs,
20 not the costs of adding new facilities, as Mr. Knecht/Ewen explain they have done in this
21 case.

22 In short, Mr. Knecht/Ewen recognize that the minimum size method PPL uses
23 produces overstated customer costs because PPL's proposed customer cost determinations
24 contain load-carrying capability, and Mr. Knecht/Ewen recognize that the capacity-related

1 costs included in PPL's cost studies are improperly allocated on a customer-count basis
2 rather than on a demand basis. Mr. Knecht/Ewen do not perform a full zero-intercept
3 analysis, which they believe would address PPL's overstatement of customer costs.
4 Unfortunately, Mr. Knecht/Ewen attempt to salvage PPL's customer costs determinations
5 by:

- 6 • less than fully applying the zero-intercept method;
- 7
- 8 • judgmentally adjusting some of PPL's customer cost determinations
9 "based on the premise that the zero-intercept minimum system should
10 have a lower customer share of costs than the PPL minimum system
11 approach." [Knecht/Ewen direct testimony, page 18, lines 4-6];
- 12
- 13 • basing their proposed customer costs on very rough calculations; and
- 14
- 15 • determining proposed customer costs on the basis of the cost of adding
16 new facilities, in violation of the very NARUC Cost Allocation
17 Manual prescriptions that Mr. Knecht/Ewen rely on to support the
18 *legitimacy of the zero-intercept method.*
19

20 Q. SHOULD THE PPL CLASS COST OF SERVICE STUDIES, WITH OR
21 WITHOUT THE CUSTOMER COST ADJUSTMENTS PROPOSED BY MR.
22 KNECHT/EWEN, BE UTILIZED TO DETERMINE HOW ANY RATE
23 INCREASE AUTHORIZED BY THE COMMISSION SHOULD BE SPREAD
24 AMONG THE CUSTOMER CLASSES, AS MESSRS. KNECHT/EWEN,
25 KINCEL, BARON AND SELECKY RECOMMEND?

26 A. The PPL cost of service studies are and continue to be unreliable indicators of the allocated
27 class cost responsibilities. The significant overstatement of customer costs, the
28 misallocation of demand-related costs on a customer-count basis, and the complete
29 omission of any cost responsibility recognition to sustained energy demands all violate the
30 cost-causality principle of cost allocation. Mr. Knecht/Ewen's study, too, fails to ascribe

1 any costs on the basis of sustained electricity demands to which PPL owes its very
2 existence, as well as containing casual, roughly calculated customer cost adjustments,
3 which are reliant on the costs of new plant in violation of the zero-intercept method
4 included in the NARUC Cost Allocation Manual. Thus, these studies do not reveal
5 reasonable estimates of allocated costs by customer class and these studies should not be
6 used to determine the spread of any rate increase authorized by the Commission.

7 Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE IMPACT ON
8 RESIDENTIAL RS CUSTOMERS INCLUDED IN THE DISTRIBUTION
9 REVENUE SPREADS PROPOSED BY THE VARIOUS PARTICIPANTS IN
10 THIS RATE PROCEEDING.

11 A. PPL proposes that Residential RS customers should pay an additional \$81 million out of a
12 total jurisdictional distribution operating revenue increase of \$164 million. Mr.
13 Knecht/Ewen propose to increase Residential RS distribution revenues by \$117 million.
14 Mr. Kincl proposes that Residential RS distribution revenues should be increased by \$120
15 million. Mr. Kincl also proposes that the Residential RS transmission revenues increase
16 from the \$24 million PPL proposed increase to a \$37 million increase. Mr. Baron proposes
17 to increase Residential RS distribution revenues by \$133 million. Mr. Baron would further
18 increase Residential RS revenue requirements automatically and between rate cases in each
19 of the next two years to eliminate the remaining revenue deficiency that he believes exists
20 under PPL's cost of service studies. Also, Mr. Baron would increase Residential RS
21 transmission revenues by \$42.9 million compared to PPL's proposed \$23.6 million
22 increase. Mr. Selecky supports PPL's \$81 million Residential RS revenue increase
23 proposal (but would not reduce the Residential RS revenues, should PPL be awarded a
24 smaller overall revenue increase compared to their requested \$164 million dollar overall

1 revenue increase). Because all these proposed revenue increase are based on the
2 acceptance of PPL's unreliable and inaccurate cost of service studies, I recommend the
3 Commission reject these revenue spread proposals.

4 Mr. Yarolin allocates to Residential RS customers 60 percent, or \$49 million, of
5 OTS's proposed \$83 million overall proposed revenue increase. Applying this percentage
6 to PPL's full \$164 million proposed rate increase would result in a Residential RS revenue
7 increase of \$98.7 million. Because substantial progress toward cost-based rates is
8 achieved under PPL's proposal to allocate approximately one-half of its proposed increase
9 to Residential RS customers, and because the most recent class cost of service study on a
10 bundled basis, as opposed to the more narrow Distribution Service-Only study results
11 available in this proceeding, shows a much closer balance between Residential RS
12 revenues and allocated costs, the Commission should not accept Mr. Yarolin's proposal to
13 allocate to Residential RS customers 60 percent of OTS's recommended revenue increase.

14 Q. PLEASE PROVIDE YOUR UNDERSTANDING OF MR. KNECHT/EWEN'S
15 CONCERN WITH USING INDEX RETURNS AS A MEASURE OF PROGRESS
16 TOWARD RATES BASED ON ALLOCATED COSTS OF PROVIDING
17 SERVICE.

18 A. At page 22, lines 12-17, Mr. Knecht/Ewen observe that, using PPL's cost of service
19 studies, the Residential RS customers' index rate of return increases from 40.9 percent of
20 system average return at present rates to 60.2 percent at PPL proposed rates. The GS-1
21 customers' index return of 237.3 percent at present rates falls to 183.7 percent at PPL
22 proposed rates. At page 21, lines 1-4 of their direct testimony, when asked, "If the indexed
23 rate of return under proposed rates is closer to 100 percent than it is under present rates,
24 has progress necessary been made?," Mr. Knecht/Ewen answer, "No. Movement of a

1 class' indexed rate of return toward 100 percent between present and proposed rates is
2 indicative of nothing." Mr. Knecht/Ewen would prefer to measure progress toward cost
3 based rates as a narrowing of the absolute, arithmetic differences between a class'
4 indicated rate of return and the overall system rate of return at present and at proposed
5 rates.

6 Based on these concerns, Mr. Knecht/Ewen propose that Residential RS
7 Distribution rates should be increased not by the PPL proposed amount of \$81 million, but
8 by an amount equal to \$117 million. Mr. Knecht/Ewen propose that GS-1 Distribution
9 rates should be increased by \$9 million instead of by the \$22 million amount PPL
10 proposes. All of these amounts are stated at PPL's full requested increase for comparative
11 purposes only.

12 Q. PLEASE COMMENT ON MR. KNECHT/EWEN'S STATED CONCERNS
13 WITH USING INDEXED RATES OF RETURN AS A MEASURE OF
14 PROGRESS TO COST BASED RATES.

15 A. Mr. Knecht/Ewen's stated concern that indexed rates of return at present and proposed
16 rates are not necessarily indicative of progress toward cost based rates is incorrect. In this
17 case, for example, as Mr. Knecht/Ewen state, using PPL's cost of service studies the
18 Residential RS indexed rate of return goes from 40.9 percent at present rates to 60.2
19 percent at proposed rates, based on PPL cost of service study results. I do not endorse
20 PPL's cost studies, but the policy prescription inherent in PPL's proposal is to move
21 Residential RS indexed returns from essentially 40 percent to 60 percent. If this policy
22 were continued, Residential RS indexed rates of return would increase from 40 percent to
23 60 percent in this case, would be at 80 percent of system return in PPL's next case, and
24 100 percent of system return in the succeeding case. Clearly, adjusting class rates so the

1 class rates of return move toward the system rate over time, consistent with the indexed
2 rate of return standard and the principle of gradualism, is a measure of progress toward
3 rates based on allocated costs of service. Contrary to Mr. Knecht/Ewen's assertions,
4 progress towards cost based rates is exhibited at PPL's proposed rate spread, and such
5 progress is not reliant on Mr. Knecht/Ewen's proposed adjustments to PPL's proposed rate
6 spread.

7 Q. PLEASE COMMENT ON MR. KNECHT/EWEN'S CHARACTERIZATION OF
8 PPL'S PROPOSED RESIDENTIAL RATES.

9 A. Mr. Knecht/Ewen limit their analysis and discussion of PPL's proposed Residential and
10 GS-1 rate spread to PPL's present and proposed Distribution rates. Mr. Knecht/Ewen are
11 correct that PPL is proposing a 26.5 percent rate increase for the provision of Distribution
12 services to Residential RS customers. However, PPL has made it perfectly clear in its
13 filing and alerts the Commission that it is also seeking to recover increased transmission
14 costs associated with providing service to its end-use customers. PPL proposes to recover
15 increasing transmission costs in a manner that would increase Residential RS transmission
16 rates by \$23.6 million in addition to present Residential RS transmission rates of \$49.1
17 million, or by 48 percent. Under PPL proposals, GS-1 customers would actually have the
18 transmission component of their rates reduced by \$483,000 from \$11,919,000 to
19 \$11,434,000, or by 4.1 percent. The total transmission rate increase identified in PPL's
20 filing is \$58.9 million compared to present transmission rates of \$147.5 million, which is a
21 40 percent transmission rate increase. Thus, PPL's proposed Residential RS rates exhibit a
22 48 percent transmission service rate increase compared to a 40 percent overall increase and
23 compared to an outright reduction for GS-1 customers. This Commission will determine
24 the allocation of revenue requirements for both the transmission cost component and the

1 distribution cost component of retail service. A complete picture of class revenue
2 increases identified by PPL in this filing and their impacts on its customers, does not
3 comport with a focus on Distribution rates only.

4 Q. DO YOU AGREE WITH MR. KNECHT/EWEN'S PROPOSAL THAT, IF THE
5 COMMISSION WERE TO APPROVE A DISTRIBUTION SYSTEM
6 IMPROVEMENT CHARGE, ALL THE COSTS SHOULD BE ALLOCATED TO
7 ONLY THOSE CLASSES WHOSE REVENUES ARE LESS THAN
8 ALLOCATED COSTS?

9 A. No. OCA witness Thomas S. Catlin addresses the impropriety of PPL's proposed DSIC.
10 However, if the Commission were to authorize a DSIC, the associated cost should not be
11 allocated solely to classes whose revenues are less than allocated costs. The rates
12 determined by the Commission in these proceedings will embody all cost and non-cost
13 considerations weighed by the Commission as it determines just and reasonable rates.
14 Consideration of only allocated costs for determining rate adjustments between rate cases
15 would change the rate relationships embodied in the just and reasonable rates determined
16 in this case. Moreover, DSICs have nothing to do with meeting increasing demands or
17 increasing number of customers, the only basis PPL used to allocate its distribution costs in
18 these proceedings.

19 Q. PLEASE SUMMARIZE MR. BARON'S PROPOSAL FOR THE SPREAD OF
20 TRANSMISSION RELATED COSTS OF SERVICE.

21 A. PPL incurs costs at PJM Open Access Transmission Tariff rates for the purchase of the
22 transmission component of the generation service that PPL provides to its retail customers.
23 Some of these transmission costs are charged on a demand basis and some are charged on
24 an energy basis. Mr. Baron would allocate the portion of PPL's total PJM bills assessed as

1 demand charges on a peak demand basis, and the portion assessed as energy charges on an
2 energy basis. The results of Mr. Baron's calculations, which are embodied in his revenue
3 spread proposals, are shown at page 28, table 3, of his direct testimony. Mr. Baron
4 proposes that Residential RS customers would receive a \$42,506,000 transmission service
5 cost/revenue increase, an 87 percent increase, compared to PPL's proposal to increase
6 Residential RS transmission service rates by \$23,505,000, a 48 percent increase.

7 Q. DO YOU AGREE WITH MR. BARON'S PROPOSED SPREAD OF PPL'S
8 ANTICIPATED \$58,238,000 TRANSMISSION COST/REVENUE
9 REQUIREMENT INCREASE?

10 A. No. As I discussed at page 22 of my direct testimony, Residential RS customers were
11 shown to be yielding an index return of 80 percent at then present rates, and 90 percent at
12 proposed rates under PPL's most recent cost study performed on all aspects of service,
13 including generation, transmission and distribution service costs. In this case, using the
14 same methodological approach to unbundled distribution service only, PPL's study shows
15 a Residential RS customer index return of 41 percent. However, over 90 percent of PPL's
16 current energy requirements continue to be provided for by PPL. During this transition
17 generation rate cap period, the reality is that the vast majority of the PPL load continues to
18 be served by PPL. We should not ignore the adequacy of Residential RS revenues on a
19 total service basis and fixate selectively on the unbundled distribution or transmission
20 components of PPL's provision of service. Residential customers are already slated for a
21 48 percent transmission service rate increase under PPL's proposed rate spread, compared
22 to a 40 percent PPL transmission service expected transmission rate increase. Considering
23 the most recent information available on PPL's overall service operations, and the already
24 greater than system average transmission rate increase under PPL's proposed rates, the

1 Commission should reject Mr. Baron's proposed transmission revenue spread that would
2 further increase Residential RS transmission revenue responsibility by \$19,000,000 in
3 addition to PPL's proposed Residential RS increase of \$23,505,000. Moreover, Mr.
4 Baron's proposal, in combination with PPL's alternating between summer and winter
5 peaking experience would produce unstable transmission rates by class.

6 Q. DO YOU AGREE WITH MR. BARON'S PROPOSAL FOR AUTOMATIC
7 CLASS RATE ADJUSTMENTS IN EACH OF THE TWO YEARS FOLLOWING
8 RATE DETERMINATIONS IN THESE PROCEEDINGS?

9 A. No. Mr. Baron proposes to change class rate schedules in each successive year after the
10 first year of the authorized rate increase in this case so as to remove one-half of any alleged
11 remaining difference between class revenues and class allocated costs each year, using
12 PPL cost study results. No guidance is presented on how this proposal would be
13 effectuated. No provision is included in Mr. Baron's proposal to address any cost/revenue
14 changes that may occur over the subsequent 3-year rate change period. No contingency is
15 provided for any follow-on rate case interface with this post-rate increase proposal, should
16 PPL file another rate case. Moreover, Mr. Baron's advice here would equate Residential
17 RS revenues and costs (at PPL's proposed study results) prior to the end of the generation
18 rate cap period.

19 Q. DOES THIS COMPLETE YOUR TESTIMONY?

20 A. Yes.

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22 00080343

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC
UTILITY COMMISSION

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DOCKET NO. R-00049255

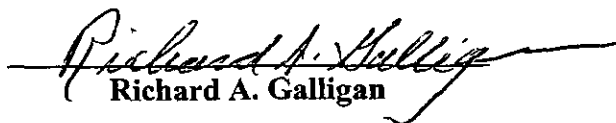
v.

PPL ELECTRIC UTILITIES
CORPORATION

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AFFIDAVIT

Richard A. Galligan being first duly sworn, deposes and says that he is the same Richard A. Galligan whose Rebuttal Testimony accompanies this affidavit: that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn testimony in this proceeding.


Richard A. Galligan

Subscribed and sworn before me on this 10 day of August, 2004.


Notary Public

My Commission Expires: _____

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ABB

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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v.

PPL ELECTRIC UTILITIES
CORPORATION

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DOCKET NO. R-00049255

SURREBUTTAL TESTIMONY
OF
RICHARD A. GALLIGAN

DOCKETED
AUG 18 2004

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

AUGUST 2004

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EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC)	
UTILITY COMMISSION)	
)	
v.)	DOCKET NO. R-00049255
)	
PPL ELECTRIC UTILITIES)	
CORPORATION)	

SURREBUTTAL TESTIMONY OF RICHARD A. GALLIGAN

- 1
- 2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.
- 3 A. My name is Richard A. Galligan. I am a Principal with Exeter Associates, Inc., a firm of
- 4 consulting economists specializing in utility economics. My business address is 5565
- 5 Sterrett Place, Suite 310, Columbia, Maryland 21044.
- 6 Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THESE
- 7 PROCEEDINGS?
- 8 A. Yes. My direct testimony and my rebuttal testimony were filed as OCA Statements No. 4
- 9 and No. 4-R, respectively.
- 10 Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?
- 11 A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of
- 12 Messrs. Oliver G. Kasper, Joseph M. Kleha, and Douglas A. Krall on behalf of PPL
- 13 Electric Utilities Corporation ("PPL" or "the Company"); Mr. Stephen J. Baron on behalf
- 14 of PPL Industrial Customer Alliance; and Messrs. Robert D. Knecht and Mark D. Ewen
- 15 on behalf of the Office of Small Business Advocate. These witnesses address cost
- 16 allocations, the rate spread and rate design issues.
- 17 Q. PLEASE COMMENT ON MR. KASPER'S CONCERN WITH ZERO USAGE
- 18 AND LOW MONTHLY RESIDENTIAL CUSTOMER BILLS.

1 A. At page 11, lines 1-8, of his rebuttal testimony, Mr. Kasper defends his proposed \$12.20
2 Residential RS monthly customer charge and his proposal to not impose an energy charge
3 on the first 200 kWh. Mr. Kasper observes that under current rates a zero usage customer
4 would pay \$6.47 per month and a 200 kWh bill would be \$10.06 per month. Mr. Kasper
5 points out that these amounts are not sufficient to recover the \$21.69 per month customer
6 cost calculated in the Company's cost of service study.

7 Mr. Kasper's sufficiency argument is based on a customer cost calculation
8 methodology that the Commission has never, to my knowledge, adopted. The \$21.69
9 monthly customer cost calculation includes all costs classified as customer-related by
10 PPL, including proposed customer costs associated with Common Distribution plant that
11 serves more than one customer. As I explain on page 24, line 18 through page 25, line 4
12 of my direct testimony, my understanding of customer costs eligible for inclusion in
13 customer charges in Pennsylvania are less than \$8 per month.

14 Consistent with PPL concerns regarding adequacy of low-usage bills, my
15 proposed residential rate design produces a \$12.58 per month residential bill for 200 kWh
16 consumption, which is quite similar to PPL's proposed \$12.20 bill. My \$8.00 proposed
17 customer charge is 24 percent higher than PPL's current \$6.47 bill at zero kWh usage.
18 This 24 percent increase compares to PPL's proposed \$12.20 bill for zero usage, which is
19 an 88 percent increase.

20 Q. MR. KASPER DISCUSSES THE OBJECTIVES ACHIEVED BY PPL'S
21 PROPOSED RESIDENTIAL RATE DESIGN. WOULD YOU PLEASE
22 ASSESS YOUR PROPOSED RESIDENTIAL RATE DESIGN TO MR.
23 KASPER'S OBJECTIVES?

24 A. At page 9, lines 4-11 of his rebuttal testimony, Mr. Kasper lists three objectives which
25 guided PPL's proposed rate design:

- 1 1. To keep the rate increase to most customers in the residential class at 10
- 2 percent or less on a total bill basis;
- 3
- 4 2. To have zero to 200 kWh usage bills make a larger contribution to
- 5 recovery of fixed costs; and
- 6
- 7 3. To begin the process of moving toward a larger fixed charge and a smaller
- 8 tail block energy rate.
- 9

10 At page 12, lines 5-6 of his rebuttal testimony, Mr. Kasper compares the absolute number
11 and the percent of bills below a 10 percent increase for PPL's, OCA's and OTS'
12 proposals. The OCA proposed rate design, producing, according to PPL's calculations,
13 65 percent of bills below a 10 percent increase, achieves Mr. Kasper's objective that most
14 residential customers receive a 10 percent or lesser bill increase on a total bill basis. Mr.
15 Kasper's second objective of having zero to 200 kWh customers make a larger
16 contribution to recovering fixed costs is achieved under my proposed rate design. A zero
17 use bill would experience a 24 percent rate increase, and a 200 kWh bill would be \$12.58
18 under my proposal compared to \$12.20 under PPL's proposed rates.

19 Mr. Kasper's third objective, reducing the tail block energy rate by increasing
20 fixed charges is improper. PPL's proposed \$12.20, customer charge is inconsistent with
21 this Commission's policy of including only certain services and meter installation capital
22 related costs and other direct costs in the customer charge. Moreover, PPL's average,
23 embedded class cost of service study is not structured to and does not reveal costs by rate
24 block. Further reducing PPL's tail block rate relative to its other rate components is not
25 supported by PPL's cost of service study. Also, PPL's customers are cycle billed. This
26 means that customers could reach the low-priced tail block usage levels at the very same

1 time that PPL is experiencing peak demands. Finally, PPL's proposal to reduce the price
2 of the first 200 kWh to zero, of course, represents a much larger reduction in this non-tail
3 block rate component compared to PPL's proposed tail block rate and is inconsistent with
4 this third PPL objective.

5 In short, my proposed residential rate design, like PPL's is consistent with the
6 first and second of Mr. Kasper's objectives. Mr. Kasper's third objective, lowering the
7 tail block rate compared to other rate element prices, is improper.

8 Q. PLEASE COMMENT ON MR. KASPER'S OBJECTIONS TO YOUR
9 PROPOSED \$1.45 RESIDENTIAL RTS CUSTOMER CHARGE INCREASE.

10 A. At page 13, lines 1-14, Mr. Kasper states his objections to my proposal to increase the
11 RTS customer charge by the same amount as the Residential RS increase. Mr. Kasper
12 states that the current customer charge does not recover all fixed costs associated with
13 serving a residential customer, and therefore a significant customer charge increase is
14 justified. Mr. Kasper also testifies in favor of retaining existing rate relationships
15 between residential tariffs. Once again, as discussed at page 24, line 18-page 25, line 4 of
16 my direct testimony and earlier in this surrebuttal testimony, it is improper to move
17 beyond a customer charge that includes the select direct costs approved for inclusion by
18 this Commission. I agree that an extra separate meter charge is appropriate for customers
19 served through an extra meter.

20 Q. MR. KLEHA DOES NOT AGREE WITH THE ALLOCATION OF A
21 PORTION OF DISTRIBUTION-RELATED FACILITIES ON THE BASIS OF
22 ENERGY, OR AVERAGE DEMANDS. PLEASE COMMENT.

23 A. At page 5 of his rebuttal testimony, Mr. Kleha testifies that allocation of distribution-
24 related facilities partially on a peak demand basis and partially on an average demand
25 basis is inappropriate for two reasons. One, Mr. Kleha argues that there is no energy

1 (arithmetically equivalent to average demand) component of distribution-related facilities
2 and expenses; and two, Mr. Kleha states that distribution facilities are sized to meet peak
3 demands.

4 I discussed at page 17, line 8 through page 19, line 4 of my direct testimony, that
5 it is customer demands, not a customer's existence, that explains PPL's existence as a
6 distribution company and it is these customers demands that drive, or account for, or
7 cause a portion of the costs that PPL experiences. I explained that building a system to
8 meet average demands, the reason for PPL's existence, would not be adequate to meet all
9 demand, because PPL's customers do not use electricity at a constant rate over the course
10 of each day of the year. Thus costs of capacity in excess of average demand
11 requirements are not caused by average demands, but are caused by peak demands. The
12 issue that Mr. Kleha and I differ on is not that peak demands are responsible for a portion
13 of capacity costs, since we both allocate a portion of capacity costs on peak demands.
14 *The issue is whether the non-peak related portion of capacity costs relates to the existence*
15 *of a customer, or to the existence of the customer's demand for energy over the course of*
16 *a year (annual demands, or the customers' average demands). Ironically, Mr. Kleha*
17 *associates no cost responsibility to the demands on which PPL owes its very existence. I*
18 *do.*

19 Q. AT PAGE 6, LINES 14-16 OF HIS REBUTTAL TESTIMONY, MR. KLEHA
20 TESTIFIES THAT THE NARUC COST ALLOCATION MANUAL DEFINES
21 A MINIMUM SIZE DISTRIBUTION SYSTEM TO BE BASED ON THE
22 SMALLEST SIZE EQUIPMENT CURRENTLY BEING INSTALLED BY THE
23 UTILITY. PLEASE COMMENT.

24 A. At page 95, comparing customer cost determination methodologies, the NARUC Manual
25 states:

1
2 The results of the minimum-size method can be influenced by
3 several factors. The analyst must determine the minimum size for
4 each piece of equipment: "Should the minimum size be based
5 upon the minimum size equipment currently installed, historically
6 installed, or the minimum size necessary to meet safety
7 requirements."
8

9 Clearly, the NARUC Manual does not uniquely define the minimum size distribution
10 system. The Manual itself raises several alternatives. Moreover the Manual is positive,
11 not normative, suggesting at page ii that the manual's objectives include a non-
12 judgmental writing style, not advocating any one particular method, but trying to include
13 all currently used methods with pros and cons.

14 Q. MR. KLEHA SUGGESTS AT PAGE 9, LINES 2-7 OF HIS REBUTTAL
15 TESTIMONY, THAT HE COULD HAVE ALLOCATED SOME PRIMARY
16 DISTRIBUTION COSTS ON A CUSTOMER BASIS, THUS OFFSETTING
17 ANY MINOR OVERSTATEMENT OF SECONDARY DISTRIBUTION
18 CUSTOMER COSTS, BUT HE DID NOT. PLEASE COMMENT.

19 A. First, Mr. Kleha, without benefit of any quantification, uses the term "minor"
20 overstatement of the customer cost component of the secondary distribution system. At
21 page 11, lines 10-18 of my direct testimony, I discuss the fact that PPL used a minimum
22 sized transformer that is very large compared to a Residential RS customer's actual
23 contribution to peak demand. Mr. Kleha has presented no evidence that his overstated
24 customer costs, based on his minimum size system equipment PPL currently installs, is
25 minor. Second, I did not ignore PPL's primary distribution plant costs. At page 19, line
26 10-page 20, line 2 of my direct testimony I explain that I provided allocation factors to
27 PPL that reallocated PPL's Primary and Common Distribution plant and related costs on
28 an average demand and peak demands basis. Potentially allocating some Primary

1 distribution plant costs on a customer-count basis is not a reasonable answer to the
2 overallocation of Secondary distribution plant costs on a customer-count basis.

3 Q. AT PAGES 28 TO 32 OF HIS REBUTTAL TESTIMONY, MR. KRALL
4 DISCUSSES THE RATE IMPLICATIONS OF ALLOCATING
5 TRANSMISSION SERVICE CHARGES ON A DEMAND/ENERGY BASIS
6 RATHER THAN AS A UNIFORM AMOUNT PER KWH. PLEASE
7 COMMENT.

8 A. Mr. Krall reiterates that PPL's original uniform amount per kWh proposal is based on its
9 simplicity and ease of administration, and to help meet its objective of having no single
10 rate class, as a whole, experience increases in its total bills in excess of 10 percent. Re-
11 allocation of TSC costs on a demand/energy basis would increase TSC cost
12 responsibilities of customer classes using relatively more demand than energy, causing
13 some customers, such as Residential RS customers to exceed the 10 percent objective.
14 Also, even under Mr. Krall's proposal, the transmission rate for residential customers
15 would fluctuate each year based on whether PPL had a summer peak or winter peak.
16 Such fluctuations can be more difficult for residential customers in understanding their
17 bills and their price to compare.

18 Q. AFTER DISCUSSING RESIDENTIAL AND GS-3 CUSTOMER PEAK
19 DEMANDS, MR. KNECHT/EWEN STATE AT PAGE 12, LINES 23-24 OF
20 THEIR REBUTTAL TESTIMONY THAT YOU REJECT ECONOMIES OF
21 SCALE IN ELECTRIC DISTRIBUTION SYSTEMS. PLEASE COMMENT.

22 A. I have allocated one-half of the average cost of Common Distribution plant on average
23 demands and one-half of those costs on peak demands. Mr. Knecht/Ewen's GS-3
24 customers have relatively high average demands compared to residential customers and
25 GS-3 customers have relatively low peak demands compared to residential customers.

1 Each class receives its proportionate share of total Common Distribution plant facilities
2 under this method. In each case and consistent with average cost study principles, the
3 average cost of a portion of capacity is allocated, mooted consideration of economies of
4 scale in the allocation process.

5 Q. AT PAGE 14, LINES 2-3 OF HIS REBUTTAL, MR. KNECHT/EWEN STATE
6 THAT THERE IS NO CAUSAL RELATIONSHIP BETWEEN ENERGY
7 CONSUMPTION AND DISTRIBUTION COSTS. ALSO, AT PAGE 14, LINES
8 17-18, MR. KNECHT/EWEN STATE THAT NO DISTRIBUTION PLANT
9 COSTS ARE CAUSED BY ENERGY CONSUMPTION. DO YOU AGREE?

10 A. No. An allocation on annual energy requirements is identical to an allocation on average
11 demands. Quite simply, if there were no sustained energy requirements (i.e., average
12 demands), there would be no PPL distribution system, or attendant costs. On the other
13 hand, because sustained energy requirements exist, PPL exists and distribution costs are
14 incurred. Mr. Knecht/Ewen, are incorrect when they state that there is no causal
15 relationship between energy (i.e., sustained demands, or average demands) and
16 distribution costs.

17 Q. AT PAGE 16, LINES 1-12, OF THEIR REBUTTAL TESTIMONY, MR.
18 KNECHT/EWEN OBJECT TO YOUR USE OF ALLOCATORS BASED ON
19 2003 DATA WHEN ALLOCATING 2004 COSTS. PLEASE COMMENT.

20 A. It is common to use load data from an earlier period to allocate more recent test year
21 costs. In fact, in this case, Mr. Knecht advocates allocating transmission costs on the
22 basis of a five-year rolling average load factor to address rate instability that would result
23 from otherwise allocating transmission costs on the basis of seasonally shifting peak
24 demands from year to year.

1 Q. MR. BARON OBJECTS TO AN ALLOCATION OF UNIVERSAL SERVICE
2 PROGRAM COSTS ON A VOLUMETRIC BASIS. PLEASE COMMENT.

3 A. At page 8, lines 5-18, of his rebuttal testimony, Mr. Baron discusses the rate increase for
4 his customers were an allocation of USP costs to be based on energy usage. There he
5 details the impact of an energy allocation on LP-5 customers as an additional 113.5
6 percent rate increase. This USP cost allocation equates to six ten-thousandths of a dollar
7 per kWh (which is 6 hundredths of a penny, or 6 tenths of a mill, per kWh). This
8 Commission will determine a policy for recouping USP costs. I also reiterate that either
9 energy or total revenue can serve as a basis for allocating these universal service costs,
10 consistent with the principle of broadly sharing these costs and minimizing the distortion
11 among customers of allocated costs of service. Allocating USP costs on revenues would
12 reduce Mr. Baron's stated 113.5 percent amount for LP-5 customers to 4.2 percent. The
13 large percentage differences relate to arithmetic percentage calculations for LP-5
14 customers who represent about 8.8 percent of deliveries and about one-third of one
15 percent of revenues.

16 Q. DOES THIS COMPLETE YOUR TESTIMONY?

17 A. Yes, it does.

18
19 00080468

20

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC
UTILITY COMMISSION

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DOCKET NO. R-00049255

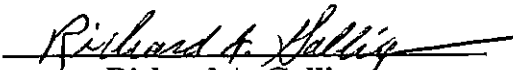
v.

PPL ELECTRIC UTILITIES
CORPORATION


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AFFIDAVIT

Richard A. Galligan being first duly sworn, deposes and says that he is the same Richard A. Galligan whose Surrebuttal Testimony accompanies this affidavit: that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn testimony in this proceeding.


Richard A. Galligan

Subscribed and sworn before me on this 10 day of August, 2004.


Notary Public

My Commission Expires: 2/2007

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R-00049255

PP&L INDUSTRIAL CUSTOMER ALLIANCE'S RESPONSES TO
PPL ELECTRIC UTILITIES CORPORATION'S INTERROGATORIES - SET 1
DOCKET NO. R-00049255

PPL-PPLICA-1 For each manufacturing facility of Armstrong World Industries, Inc. in PPL Electric's service territory, provide separately the total expenses incurred by Armstrong World Industries to operate the facility during 2003 and provide the cost of electric service during 2003 at present rates and at proposed rates at the level of usage during 2003.

DOCUMENT

RESPONSE: To avoid the disclosure of information that Armstrong considers to be highly proprietary and confidential, PPL has agreed to accept the following response to this interrogatory:

The cost of distribution service at Armstrong's facilities in the PPL service territory is less than one half of one percent (0.5%) of Armstrong's estimated labor costs at the facilities.

DOCKETED

Response provided by: James H. Rooney

AUG 18 2004

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PP&L INDUSTRIAL CUSTOMER ALLIANCE'S RESPONSES TO
PPL ELECTRIC UTILITIES CORPORATION'S INTERROGATORIES - SET 1
DOCKET NO. R-00049255

R-00049255

PPL-PPLICA-2 For each manufacturing facility of Anvil International, Inc. in PPL Electric's service territory, provide separately the total expenses incurred by Anvil International, Inc. to operate the facility during 2003 and provide the cost of electric service during 2003 at present rates and at proposed rates at the level of usage during 2003.

DOCUMENT

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AUG 18 2004

RESPONSE: To avoid the disclosure of information that Anvil considers to be highly proprietary and confidential, PPL has agreed to accept the following response to this interrogatory:

At the current rates, Anvil's transmission and distribution charges are approximately 0.6% of its 2003 operating costs (excluding materials). At the rates proposed by PPL, Anvil's transmission and distribution charges will be approximately 1.1% of its 2003 operating costs (excluding materials). If adopted, the PPL proposal will result in a 3.8% increase to Anvil's total annual utility costs (electric, natural gas, water, sewer, liquid nitrogen, and liquid oxygen).

Response provided by: Aaron Croop

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PP&L INDUSTRIAL CUSTOMER ALLIANCE'S RESPONSES TO
PPL ELECTRIC UTILITIES CORPORATION'S INTERROGATORIES - SET 1
DOCKET NO. R-00049255

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PPL-PPLICA-3 For each manufacturing facility of BOC Gases in PPL Electric's service territory, provide separately the total expenses incurred by BOC Gases to operate the facility during 2003 and provide the cost of electric service during 2003 at present rates and at proposed rates at the level of usage during 2003.

DOCUMENT

DOCKETED

AUG 18 2004

RESPONSE: To avoid the disclosure of information that BOC considers to be highly proprietary and confidential, PPL has agreed to accept the following response to this interrogatory:

The cost of transmission and distribution service at BOC's facility in the PPL service territory is approximately 13% of the average total operating cost for a BOC air separation unit.

Response provided by: Larry Stalica

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PP&L INDUSTRIAL CUSTOMER ALLIANCE'S RESPONSES TO
PPL ELECTRIC UTILITIES CORPORATION'S INTERROGATORIES - SET 1
DOCKET NO. R-00049255

PPL-PPLICA-4 For each manufacturing facility of Praxair, Inc. in PPL Electric's service territory, provide separately the total expenses incurred by Praxair, Inc. to operate the facility during 2003 and provide the cost of electric service during 2003 at present rates and at proposed rates at the level of usage during 2003.

DOCUMENT

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AUG 18 2004

RESPONSE: To avoid the disclosure of information that Praxair considers to be highly proprietary and confidential, PPL has agreed to accept the following response to this interrogatory:

For a typical 10 MW air separation unit with a 90% average load factor and based on publicly available information that electricity constitutes 50% of a typical air separation facility's operating costs: (a) at PPL's current rates, transmission and distribution costs are approximately 5.4% of total operating costs; and (b) at PPL's proposed rates, transmission and distribution would be approximately 7.8% of total operating costs.

Response provided by: Jennifer Hunsperger.

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OTS Statement No. 4
Witness: Paul M. Yarolin
Date: June 29, 2004

8-12-04 JES

ASB

w/EXH 4

+ ERRATA

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Includes
OTS
Exhibit 4

Docket No. R-00049255

DOCKETED
AUG 18 2004

DOCUMENT

Direct Testimony

of _____

Paul M. Yarolin

Office of Trial Staff

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Concerning:

Rate Structure Issues

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Paul M. Yarolin and my business address is the P.O. Box 3265,
3 Harrisburg, Pennsylvania 17105-3265.

4
5 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

6 A. I am employed by the Pennsylvania Public Utility Commission in the Office of
7 Trial Staff as a Fixed Utility Valuation Engineer.

8
9 **Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

10 A. I earned an Associate Degree in Mechanical Engineering from the Pennsylvania
11 State University in 1963 and a Bachelor of Science Degree in Commerce and
12 Finance from Wilkes College in 1971.

13
14 **Q. HAVE YOU HAD ANY ADDITIONAL TRAINING WHILE EMPLOYED
15 BY THE COMMISSION?**

16 A. Yes. See attached Appendix A.

17
18 **Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE THIS
19 COMMISSION?**

20 A. Yes, details of my experience as an expert witness are shown in Appendix A.

1 Q. HOW LONG HAVE YOU BEEN EMPLOYED BY THE PENNSYLVANIA
2 PUBLIC UTILITY COMMISSION?

3 A. I have been employed by the Pennsylvania Public Utility Commission since 1974.
4

5 Q. WHAT ARE YOUR RESPONSIBILITIES AS A FIXED UTILITY
6 VALUATION ENGINEER?

7 A. As a Fixed Utility Valuation Engineer in the Technical Division of the Office of
8 Trial Staff (OTS), I am responsible for the review and analysis of valuation,
9 depreciation, cost of service, revenues and rate design.
10

11 Q. WHAT SPECIFIC ISSUES WILL YOU ADDRESS IN YOUR DIRECT
12 TESTIMONY?

13 A. I will address the following issues: 1) Rate Schedule RS (Residential Service); 2)
14 Rate Schedule (RTS) – Residential Thermal Service; 3) Rate Schedules GS-1 and
15 G-3 (Volunteer Fire Company, Non-profit senior citizen centers, rescue squads and
16 ambulance services; 4) Remaining Rate Schedules; and 5) Summary.
17

18 Q. WHAT IS THE COMPANY'S PROPOSED INCREASE TO ITS REVENUE
19 REQUIREMENT?

20 A. The Company is proposing to increase its revenue requirement by \$164,436,766.

1 Q. HOW IS THE COMPANY PROPOSING TO ALLOCATE THE INCREASE
 2 OF \$164,436,766 IN ITS REVENUE REQUIREMENT?

3 A. The \$164,436,766 increase in the revenue requirement would be obtained from the
 4 following rate schedules:

5	<u>Rate</u>	<u>Proposed Revenue</u>	<u>Proposed %</u>
6	<u>Schedule</u>	<u>Increase</u>	<u>Increase</u>
7			
8	RS (Residential Service)	\$80,930,691	7.49
9			
10	RTS(R) (Residential Service		
11	Thermal Storage)	568,224	2.41
12			
13	RTD(R) (Residential Service		
14	Time-of-Day)	32,127	7.64
15			
16	GS-1 (Small General Service at		
17	Secondary Voltage)	21,958,604	10.16
18			
19	GS-3 (Large General Service at		
20	Secondary Voltage)	43,087,505	6.61
21			
22	LP-4 (Large General Service at		
23	12,470 Volts)	10,750,484	3.27
24			
25	IS-P(R) (Interruptible Large General		
26	Service at 12,470 Volts or		
27	Higher)	383,427	1.90
28			
29	LP-5 (Large General Service at		
30	69,000 Volts or Higher)	18,733	0.01
31			
32	IS-T(R) (Interruptible Large General		
33	Service at 69,000 Volts or		
34	Higher)	(564,896)	-0.70
35			
36	LP-6 (Large General Service at		
37	69,000 Volts or Higher)	(97,808)	-0.34

1	LPEP (Power Service to Electric		
2	Propulsion)	90,802	1.94
3			
4	ISA (Interruptible Service by		
5	Agreement)	84	0.00
6			
7	IS-1(R) (Interruptible Service –		
8	Greenhouses)	12,701	8.55
9			
10	BL (Borderline Service –		
11	Electric Service)	56,990	10.20
12			
13	SA (Private Area Lighting)	372,717	8.75
14			
15	SM (Mercury Vapor Street		
16	Lighting)	83,755	8.63
17			
18	SHS (High Pressure Sodium		
19	Street Lighting)	1,594,681	9.06
20			
21	SE (Energy Only Street		
22	Lighting)	43,568	4.72
23			
24	TS(R) (Municipal Traffic Signal		
25	Lighting)	3,257	7.87
26			
27	SI-1(R) Municipal Street Lighting)	1,870	8.84
28			
29	GH-1(R) (Single Meter Commercial		
30	Space Heating)	2,436,077	8.80
31			
32	GH-2(R) (Separate Meter General		
33	Space Heating)	534,741	8.81
34			
35	Standby (Standby Service for		
36	Qualifying Facilities)	<u>46,696</u>	4.11
37			
38	Rate Revenue	\$163,345,029	6.07
39			
40	Annualized Adjustments	<u>1,522,774</u>	12.14

1	Total PUC Tariff Revenue	\$163, 867,803	6.10
2			
3	Late Payment	<u>568,963</u>	9.48
4			
5	Total Operating Revenue		
6			
7	Increase	<u>\$164,436,766</u>	<u>6.03</u>

8

9 **Q. DOES THE \$164,436,766 OPERATING REVENUE INCREASE INCLUDE**
10 **ANY REVENUES FROM TRANSMISSION SERVICES?**

11 **A.** No. The proposed operating revenue increase of \$164,436,766 is only from
12 distribution service.

13

14 **Q. WHAT IS THE OTS RECOMMENDED OPERATING REVENUE**
15 **INCREASE?**

16 **A.** The OTS recommended operating revenue increase is approximately \$83,000,000.

17

18 **SECTION I – RATE SCHEDULE RS (RESIDENTIAL SERVICE)**

19

20 **Q. WHAT ARE THE CURRENT RATES FOR RATE SCHEDULE RS?**

21 **A.** Currently, the customer charge is \$6.55 per month. The distribution usage charge
22 for the first 200 kWh is \$0.01817 per kWh. For the next 600 kWh, the charge is

1 A. I am proposing that the monthly customer charge be increased from the present
2 \$6.55 to \$8.25 without the inclusion of a non-chargeable distribution charge for
3 the first 200 kWh of usage.

4
5 **Q. WHAT IS THE PURPOSE OF THE CUSTOMER CHARGE?**

6 A. The customer charge is a recurring charge which is independent of the quantity of
7 energy used. Its purpose is to recover customer related costs such as meter
8 reading, billing, collection, accounting, metering equipment and service
9 connections. These costs will vary with the number of customers served.

10
11 **Q. IS THIS THE BASIS FOR YOU NOT INCLUDING THE 200 KWH OF**
12 **DISTRIBUTION USAGE IN THE CUSTOMER CHARGE?**

13 A. Yes.

14
15 **Q. YOU STATED THAT YOU ARE PROPOSING TO INCREASE THE**
16 **PRESENT MONTHLY CUSTOMER CHARGE OF \$6.55 TO \$8.25. HOW**
17 **DID YOU QUANTIFY YOUR PROPOSAL?**

18 A. In the absence of a specific cost study which shows the cost for the 200 kWh that
19 the Company proposes to include in the customer charge, I developed a factor
20 which is the percentage of current residential customer charge revenues to

1 \$0.01612 per kWh and for any usage in excess of 600 kWh, the charge is \$0.01489
2 per kWh.

3

4 **Q. WHAT ARE THE COMPANY'S PROPOSED RATES FOR RATE**
5 **SCHEDULE RS?**

6 A. The Company is proposing that the customer charge be increased from \$6.55 per
7 month to \$12.20 per month with no distribution charge for the first 200 kWh of
8 usage. The distribution charge for the next 600 kWh of usage is proposed to be
9 increased to \$0.02198 per kWh and for all additional usage, the charge would be
10 \$0.01879 per kWh.

11

12 **Q. WHY IS THE COMPANY PROPOSING NOT TO HAVE A**
13 **DISTRIBUTION CHARGE FOR THE FIRST 200 KWH?**

14 A. The Company states that its objective is to move toward fixed collections while
15 keeping the increase for about 90% of residential bills to less than 10% on a total
16 bill basis (Mr. Krall Statement No. 4, page 29, line 18).

17

18 **Q. WHAT CUSTOMER CHARGE ARE YOU PROPOSING FOR RATE**
19 **SCHEDULE RS?**

1 the current total residential distribution revenues. The current residential customer
2 charge revenues are \$89,468,860 and the total distribution revenues are
3 \$296,700,088. The resulting factor is .3015 ($.3015 = \$89,468,860 / \$296,700,088$).
4 This factor can then be applied to the revenues that are allocated to Rate Schedule
5 RS so that the customer charge revenues can be established with a monthly
6 customer charge. The residual revenues can then be applied to distribution usage
7 charge revenues. By utilizing this methodology, the current revenue relationship
8 between the customer charge revenues and distribution usage revenues can
9 continue under proposed rates (O. G. Kasper, Attachment IV-C, page 1).

10
11 **Q. WHY DO YOU BELIEVE IT IS APPROPRIATE TO USE SUCH A**
12 **FACTOR?**

13 A. It is my opinion that the customer charge should be independent of usage as is the
14 case with other utilities' rate structures because of the functions involved. Also,
15 the Company's current rates are indicative of this concept with separate rates for
16 the customer charge and distribution usage charges. In order to maintain this
17 relationship, the use of a factor based on current rate revenues for this rate
18 schedule is appropriate.

1 Q. WHAT WOULD BE THE ADDITIONAL REVENUE GENERATED FROM
2 INCREASING THE MONTHLY CUSTOMER CHARGE FROM \$6.55 TO
3 \$8.25?

4 A. With a proposed monthly customer charge of \$8.25, the annual revenue would be
5 approximately \$114,011,964 (1,151,636 customers x 12 months x \$8.25 per
6 month) for residential customers in Rate Schedule RS compared to current
7 revenues of \$90,518,590 or an annual increase of \$23,493,374 (Exhibit Future 1,
8 Summary of Measures of Value & Rate of Return, D3, Page 2).

9
10 Q. WHAT CHANGES WOULD YOU RECOMMEND FOR THE
11 DISTRIBUTION CHARGE?

12 A. I recommend that the distribution charges have two steps. The first step would
13 include the first 800 kWh and the second step would include all kWh in excess of
14 800 kWh.

15
16 Q. WHY DO YOU RECOMMEND TWO DISTRIBUTION USAGE STEPS
17 AND THEIR CORRESPONDING USAGE LEVELS?

18 A. First of all, it is a step in the direction of eventually having a single distribution
19 rate and phasing out the current three usage steps. With the reduction of the usage
20 steps, there would be less confusion among customers in understanding their bill.

1 Also, since the median usage is about 700 kWh per month, the typical residential
2 customer's usage will fall within the first distribution usage step (Company
3 Statement No. 4, Page 30, line 15).

4
5 **Q. WHAT RATES ARE YOU PROPOSING FOR THE DISTRIBUTION**
6 **USAGE STEPS FOR RATE SCHEDULE RS?**

7 A. As previously stated, I am recommending that Rate Schedule RS have two rate
8 steps. The first rate step would be the first 800 kWh and the second step 801 kWh
9 and greater. The first 800 kWh rate would be \$0.01892/kWh and the second step
10 of 801 kWh and greater would be \$0.01680/kWh.

11
12 **Q. WHY DID YOU CHOOSE THESE SPECIFIC RATES?**

13 A. Based upon the OTS recommended revenue requirement, and the fact that the rate
14 of return for Rate Schedule RS is below the system average rate of return, I believe
15 my proposed rate design aids in moving rates towards cost and establishes rates
16 that are fair and equitable.

17
18 **Q. APPROXIMATELY WHAT REVENUE INCREASE WILL YOUR**
19 **PROPOSED DISTRIBUTION USAGE RATES FOR RATE SCHEDULE RS**
20 **PRODUCE?**

1 A. With a rate of \$0.01892/kWh for the first step the revenue produced will be
2 approximately \$150,771,766 (7,968,912,240 kWh x \$0.01892/kWh). The
3 proposed rate for the second step is \$0.01680/kWh and it will produce
4 approximately \$82,766,088 (4,925,733,000 kWh x \$0.01680/kWh). The revenue
5 increase resulting from the OTS proposed distribution usage charges will be
6 approximately \$26,306,626, based upon a distribution usage of 12,894,588,000
7 kWh.

8
9 **Q. WITH THE PROPOSED INCREASE IN THE CUSTOMER CHARGE TO**
10 **\$8.25 AND THE PROPOSED INCREASES IN THE DISTRIBUTION**
11 **USAGE RATES, WHAT WILL BE THE APPROXIMATE REVENUE**
12 **INCREASE FROM RATE SCHEDULE RS?**

13 A. The increase will be approximately \$49,800,000 (\$23,493,374 + \$26,306,626).

14
15 **Q. WHAT WILL YOUR PROPOSED RATE DESIGN FOR RATE**
16 **SCHEDULES RS HAVE ON ITS RATE OF RETURN?**

17 A. Under my rate design for Rate Schedule RS, \$49,800,000 or 60% of the
18 \$83,000,000 revenue increase recommended by OTS will be assigned to this rate
19 schedule. With this revenue assignment, Rate Schedule RS will move towards the
20 average rate of return of 7.51% recommended by OTS.

1 this negative return, I believe that an increase in rates greater than that proposed by
2 the Company is warranted (Company Exhibit JMK 2, Pages 76, 77, 87 and 88).

3
4 **Q. WHAT IS THE SYSTEM AVERAGE RATE OF RETURN CLAIMED BY**
5 **THE COMPANY IN THIS FILING?**

6 A. The system average rate of return claimed by the Company is 8.80%.

7
8 **Q. WHAT RATES ARE PROPOSED BY THE COMPANY FOR**
9 **RESIDENTIAL THERMAL STORAGE SERVICE?**

10 A. The Company is proposing to increase the Customer Service charge from \$15.21
11 per month to \$20.20 per month, but reduce the distribution charge for on-peak KW
12 from \$0.90/KW to \$0.563/KW.

13
14 **Q. WHAT MONTHLY CUSTOMER CHARGE DO YOU PROPOSE FOR**
15 **RESIDENTIAL THERMAL STORAGE SERVICE?**

16 A. Because of its negative rate of return for this service, I recommend that the
17 monthly customer charge that is proposed by the Company be implemented. By
18 increasing the monthly customer charge from \$15.21 to \$20.20 will produce an
19 increase in revenues of approximately \$858,799.

1 **Q. DO YOU AGREE WITH THE COMPANY IN REDUCING THE**
2 **DISTRIBUTION CHARGE FOR ON-PEAK KW IN EXCESS OF 2KW**
3 **FROM \$0.90/KW TO \$0.563/KW FOR RESIDENTIAL THERMAL**
4 **STORAGE SERVICE?**

5 A. No, I do not. For a service which shows a negative rate of return, a reduction in
6 rates is not warranted. In order to improve the rate of return for this service, I
7 recommend increasing the present charge of \$0.90/KW for any KW in excess of 2
8 on-peak KW to a rate whereby the negative rate of return is eliminated. The
9 amount of increase needed to achieve a zero return would be established at the
10 time of the compliance filing.

11
12 **Q. WITH YOUR PROPOSED INCREASES FOR RATE SCHEDULE RTS,**
13 **WHAT EFFECT WILL IT HAVE ON THIS SERVICE'S RATE OF**
14 **RETURN?**

15 A. With the OTS proposed increases for this service, the rate of return increases from
16 a -3.95% to 0%.

1 **SECTION III – RATE SCHEDULES GS-1 AND GS-3**

2 **VOLUNTEER FIRE COMPANY, NON-PROFIT SENIOR CITIZEN CENTERS,**

3 **RESCUE SQUADS AND AMBULANCE SERVICES**

4
5 **Q. WHAT IS THE DIFFERENCE BETWEEN A RATE SCHEDULE GS-1**
6 **AND RATE SCHEDULE GS-3?**

7 **A.** Rate Schedule GS-1 is for small general service customers who are served by a
8 secondary voltage of 12 KV or less. Rate Schedule GS-3 is for large general
9 service customers who are also served by a secondary voltage of 12 KV, but where
10 necessary, the Company furnishes and maintains one transformation from line
11 voltage to a lower Company standard service voltage.

12
13 **Q. WHAT RATES DOES THE COMPANY PROPOSE FOR THE**
14 **VOLUNTEER FIRE COMPANIES, NON-PROFIT SENIOR CITIZEN**
15 **CENTERS, RESCUE SQUADS AND AMBULANCE SERVICES?**

16 **A.** The proposed rates for these non-profit organizations are the same as those
17 proposed for residential customers under Rate Schedule RS. The Company is
18 proposing that the customer charge be increased from \$6.55 per month to \$12.20
19 per month with no distribution charge for the first 200 kWh of usage. The
20 distribution charge for the next 600 kWh would increase from \$0.01612 per kWh

1 to \$0.02198 per kWh and for all usage in excess of this amount, the charge
2 increases from \$0.01489 per kWh to \$0.01879.

3
4 **Q. WHY DO THESE NON-PROFIT ORGANIZATIONS, WHO ARE BEING**
5 **SERVED UNDER THE GS-1 AND GS-3 RATE SCHEDULES, HAVE**
6 **RATES THAT MIRROR RESIDENTIAL RATES UNDER RATE**
7 **SCHEDULE RS-1?**

8 A. According to 66 Pa. C.S.A. §1511, those listed non-profit organizations who are
9 being served under Rate Schedules GS-1 and GS-3 must have equivalent rates to
10 that of residential service. Therefore, the rate structure I propose for Rate Schedule
11 RS would also apply to those non-profit organizations who are being served under
12 Rate Schedules GS-1 and GS-3.

13
14 **SECTION IV – REMAINING RATE SCHEDULES**

15 **Q. WHAT RATE DESIGN ARE YOU PROPOSING FOR THOSE SERVICES**
16 **WHICH HAVE NOT BEEN SPECIFICALLY ADDRESSED IN YOUR**
17 **TESTIMONY?**

18 A. For those remaining rate schedules not specifically addressed in my testimony, I
19 would residually price those services with the remaining portion of the OTS

1 recommended revenue increase of \$83,000,000 so that the same rate relationship
2 between the rate schedules is maintained as proposed by the Company.

3
4 **Q. IF THE COMMISSION ALLOWS A REVENUE REQUIREMENT**
5 **INCREASE THAT EXCEEDS THAT PROPOSED BY THE OTS, HOW**
6 **SHOULD THAT REVENUE EXCESS BE APPLIED TO THE RATE**
7 **SCHEDULES?**

8 A. I recommend that any revenues in excess of \$83,000,000, proposed by OTS, be
9 applied across the board to all rate schedules proposed by the Company in this
10 filing. With the application of any excess revenues in this manner, the rate of
11 return for the various rate schedules can approach the system average rate of return
12 without causing rate shock.

13
14 **SECTION V – SUMMARY**

15
16 **Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?**

17 A. Yes. The following is a summary of my recommendations:

- 18 1) That the customer charge for Rate Schedule RS be increased to \$8.25 per
19 month.

- 1 2) That the distribution usage charge include two rate steps. The first rate step
2 includes the first 800 kWh at a rate of \$0.01892/kWh and the second step
3 includes all usage in excess of 800 kWh at a rate of \$0.01680/kWh.
- 4 3) That Rate Schedule (RTS) – Residential Thermal Service have its customer
5 charge increased to \$20.20 per month as proposed by the Company.
- 6 4) That the distribution charge for on-peak KW in excess of 2KW be increased
7 from \$0.90/KW to a rate level whereby the negative rate of return is
8 eliminated.
- 9 5) That Rate Schedules GS-1 and GS-3 for Volunteer Fire Companies, Non-
10 profit Senior Citizens Centers, Rescue Squads and Ambulance services
11 mirror the rates of Rate Schedule RS.
- 12 6) That the remaining rate schedules not addressed be residually priced so that
13 the same rate relationship schedules is maintained as proposed by the
14 Company.
- 15 7) That any revenues in excess of that proposed by the OTS be applied across
16 the board for all Rate Schedules proposed for an increase by the Company.
- 17

18 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

19 **A. Yes.**

PAUL M. YAROLIN
Appendix A

Training and Experience

Training:

In September of 1975, I participated in a program at Western Michigan University entitled Fundamentals of Depreciation.

In 1976, I completed the Pennsylvania State University Continuity Education course on the Physical Functioning of Public Utility Equipment.

In July 1976, I attended the Depreciation Training Program at Western Michigan University entitled Fundamentals of Life and Salvage Estimation.

In February 1977, I attended a Symposium at the University of Missouri involving rate design problems of regulated industries.

In September 1978, I attended a seminar sponsored by the Bell's Center for Technical Education at Des Plaines, Illinois, on Cost for Pricing Decisions with an emphasis on incremental analysis.

In December 1983, I attended a Telecommunications Conference in Williamsburg, Virginia, concerning Regulation, Markets, and Technology and its impact on public utility pricing.

In June 2001, I attended the National Conference of Regulatory Utility Commission Engineers for electric reliability, deregulation and technology concerns.

Professional Affiliation

Member and past Second Vice President for the Engineers Society of Pennsylvania.

Rate Case Witness Experience:

I have appeared or presented testimony before the Pennsylvania Public Utility Commission as a witness in the following general rate filings:

General Telephone Company of Pennsylvania	R-79100962 R-811512
The Bell Telephone Company of Pennsylvania	R-80061235 R-811819 R-841779
Continental Telephone Company of Pennsylvania	R-850044 R-850083
Quaker State Telephone Company	R-850045
Mahanoy and Mahantango Telephone Company	R-870590
Western Pennsylvania Water Company	R-870825
Pennsylvania Gas and Water Company	R-870853
Pennsylvania American Water Company	R-880916
Philadelphia Electric Company	R-881089
Dauphin Consolidated Water Company	R-891259
T.W. Phillips Gas and Oil Company	R-911889
Columbia Gas of Pennsylvania, Inc.	R-910873
Dauphin Consolidated Water Supply Company	R-912000
The Peoples Natural Gas Company	R-922206
Dauphin Consolidated Water Supply Company	R-932604
National Fuel Gas Distribution Corporation	R-932548

Pennsylvania American Water Company	R-932670
Pennsylvania Power & Light Company	R-943271
The Peoples Natural Gas Company	R-943252
UGI Utilities, Inc.	R-963646
Columbia Gas of Pennsylvania, Inc.	R-973931
UGI Utilities, Inc.	R-974012
United Water Pennsylvania, Inc.	R-973947
West Penn Power Co.	R-973981
Duquesne Light Co.	R-974104
Columbia Gas of Pennsylvania, Inc.	R-984307
UGI Utilities, Inc.	R-984352
United Telephone Company	P-981410
Columbia Gas Company	R-994612
The York Water Company	R-994605
PG Energy, Inc.	R-994783
UGI Utilities, Inc.	R-994786
T. W. Phillips Gas and Oil Company	R-005459
Columbia Gas of Pennsylvania, Inc.	R-016179
Columbia Gas of Pennsylvania, Inc.	R-027204
PG Energy, Inc.	R-027385
York Water Co.	R-027975
Pennsylvania American Water Company	R-038304

Columbia Gas of Pennsylvania, Inc.

R-049234

OTS Exhibit No. 4
Witness: Paul M. Yarolin
Date: June 29, 2004

8-12-04 JEF
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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-00049255

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Exhibit to Accompany

the

Direct Testimony

of

Paul M. Yarolin

Office of Trial Staff

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

DOCKETED

AUG 18 2004

Concerning:

Rate Structure Issues

**PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set 17,
Dated June 1, 2004**

Docket No. R-00049255

- Q.OTS-RS-76.** In reference to Exhibit JMK 2, Pages 10 and 11, the rate of return for each rate schedule is shown.
- A.** For rate schedule RTS, the rate of return is a negative 3.21%. Why hasn't the Company proposed a larger increase for this service in order to eliminate a negative return in this filing?
 - B.** For rate schedule RTS, the rate of return is a negative 3.21%. Why hasn't the Company proposed a larger increase for this service in order to eliminate a negative return in this filing?
 - C.** Although this service was not open to new customers since December 31, 1995, what investment was required by the customer and approximately what was the cost?
 - D.** Is this service closed to a given customer or just a customer location?
 - E.** How many customers were there at the peak of this service offering and how many are there currently?
- A.OTS-RS-76. A.&B.** PPL Electric set an objective to keep the combined increase for transmission service and distribution service below 10% of the total billed revenue for all rate classes (see the Direct Testimony of Douglas A. Krall, Statement No. 4). Rate Schedule RTS currently has a disproportionately low transmission service charge. The proposed flat rate for transmission service to all customers produces almost a 7% increase for this rate schedule. Therefore, only a small increase was possible in the distribution service rate to meet the objective of keeping the total increase below 10%. The resulting distribution increase was not sufficient to produce a positive rate of return.
- C.** The Company does not maintain any record of equipment installed by customers or the cost of that equipment.

Several types of thermal storage heating systems were installed in the early 1990s. Typically heating systems included air-to-air heat pumps with thermal storage, ground source heat pumps with thermal storage, or ceramic room installations. Many variations of these systems were installed, however, each needed to provide some method of thermal storage in order to qualify for Rate Schedule RTS.

- D. Rate Schedule RTS is closed to new applicants. In addition, it is limited to existing service locations, through the life of the existing thermal storage systems.
- E. At its peak in March 1996, there were 14,600 customers taking service under Rate Schedule RTS. As of April, 2004, there are 14,000 customers taking service under Rate Schedule RTS.

**PPL ELECTRIC UTILITIES CORPORATION
DOCKET NO. R-00049255**

**OTS STATEMENT NO. 4
ERRATA SHEET**

1. Page 5, line 16, delete \$83,000,000 and insert \$101,464,000.
2. Page 10, line 9, delete \$0.01892/kWh and insert \$0.01982/kWh.
3. Page 10, line 10, delete \$0.01680/kWh and insert \$0.01760/kWh.
4. Page 11, line 1, delete \$0.01892/kWh and insert \$0.01982/kWh.
5. Page 11, line 2, delete \$150,771,766 and insert \$157,982,413.
6. Page 11, line 2, delete \$0.1892/kWh and insert \$0.01982.
7. Page 11, line 3, delete \$0.01680/kWh and insert \$0.0176/kWh.
8. Page 11, line 4, delete \$82,766,088 and insert \$86,687,841/kWh.
9. Page 11, line 4, delete \$0.01680/kWh and insert \$0.01760/kWh.
10. Page 11, line 6, delete \$26,306,626 and insert \$37,385,026.
11. Page 11, line 13, delete \$49,800,000 and insert \$60,878,400.
12. Page 11, line 13, delete \$26,306,626 and insert \$37,385,026.
13. Page 11, line 17, delete \$49,800,000 and insert \$60,878,400.
14. Page 11, line 18, delete \$83,000,000 and insert \$101,464,000.
15. Page 11, line 20, delete 7.51% and insert 7.63%.
16. Page 17, line 1, delete \$83,000,000 and insert \$101,464,000.
17. Page 17, line 8, delete \$83,000,000 and insert \$101,464,000.
18. Page 18, line 2, delete \$0.01892/kWh and insert \$0.01982/kWh.
19. Page 18, line 3, delete \$0.01680/kWh and insert \$0.01760/kWh.

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OTS Statement No. 4-SR
Witness: Paul M. Yarolin
Date: August 5, 2004

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-00049255

DOCKETED
AUG 18 2004

Surrebuttal Testimony

of

Paul M. Yarolin

Office of Trial Staff

Concerning:

Rate Structure

1 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

2 A. My name is Paul M. Yarolin. My business address is P.O. Box 3265,
3 Harrisburg, Pennsylvania 17105-3265.

4
5 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

6 A. I am employed by the Public Utility Commission in the Office of Trial Staff as a
7 Fixed Utility Valuation Engineer.

8
9 Q. HAVE YOU PREPARED AND SUBMITTED DIRECT TESTIMONY
10 IN THIS PROCEEDING?

11 A. Yes. I have submitted OTS Statement No. 4.

12
13 Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

14 A. The purpose of my surrebuttal testimony is to address the rebuttal testimony
15 submitted by the PPL Electric Utilities Corporation witness Oliver G. Kasper.

16
17 Q. IN YOUR DIRECT TESTIMONY, YOU STATED THAT OTS'S
18 RECOMMENDED REVENUE INCREASE IS \$83,000,000. WAS THIS
19 THE CORRECT REVENUE INCREASE PROPOSED BY THE OTS AT
20 THE TIME YOU FILED YOUR TESTIMONY?

21 A. No. The \$83,000,000 was in error. The revenue increase should have been
22 \$73,000,000. During the rebuttal stage of the proceeding, there have been a

1 number of adjustments and revisions by the Company and OTS. Accordingly, the
2 revised revenue increase recommended by OTS is \$101,464,000.

3
4 **Q. WITH THIS REVISION TO THE REVENUE INCREASE, WHAT**
5 **CHANGES IN RATES ARE YOU PROPOSING FOR RATE SCHEDULE**
6 **RS?**

7 A. I am not making any changes to my proposed customer charge of \$8.25 per
8 month, as stated in my direct testimony; however, I am making adjustments
9 to my proposed usage charges for two rate steps.

10
11 **Q. WHAT WOULD BE YOUR RATE SCHEDULE RS USAGE CHARGES**
12 **WITH A \$101,464,000 OVERALL REVENUE INCREASE INSTEAD OF**
13 **\$83,000,000 AS REFERENCED IN YOUR DIRECT TESTIMONY?**

14 A. For Rate Schedule RS, the first 800 kWh rate would be approximately
15 \$0.01982/kWh instead of \$0.01892 and the second rate step of 801 kWh and
16 greater would be \$0.01760/kWh instead of \$0.01680/kWh.

17
18 **Q. WHAT WILL BE THE APPROXIMATE REVENUE RECEIVED**
19 **FROM YOUR ADJUSTED REVENUE INCREASE OF \$101,464,000?**

20 A. With a customer charge of \$8.25 per month, the revenue produced will be
21 \$114,011,964. With a charge of \$0.01982/kWh for the first 800 kWh of usage, the
22 revenue would be approximately \$157,928,413 and \$86,687,841 for the second

1 rate step whose rate would be \$0.01760. The total revenue from the OTS
2 proposed usage charges would be approximately \$244,616,254 (\$157,928,413 +
3 \$86,687,841). With \$114,011,964 from an \$8.25 customer charge and
4 \$244,616,254 from usage charges, the total revenue from Rate Schedule RS will
5 be \$358,628,218 (\$114,011,964 + \$244,616,254).

6
7 **PPL Electric Utilities Corporation Position**

8 **Q. IS MR. KASPER'S CHARACTERIZATION OF YOUR POSITION**
9 **ACCURATE?**

10 A. No. Because of the various adjustments and revisions by the Company and OTS,
11 which were previously mentioned, the proposed revenue increase is now
12 \$101,464,000. Instead of the total revenue being \$347,549,818, it should be
13 \$358,628,218.

14
15 **Q. ARE THE PERCENT OF REVENUES RECEIVED FROM RATE**
16 **SCHEDULE RS CORRECT AS INDICATED BY MR. KASPER**
17 **CORRECT ON PAGE 7, LINE 18?**

18 A. No. Based upon revenues of \$358,628,218, the customer charge revenue should
19 be 31.79%, the revenue from the first 800 kWh should be 44.04% and the
20 revenue from all kWh over 800 kWh should be 24.17%.

1 **Q. ARE THERE ANY OTHER ERRORS THAT YOU WISH TO ADDRESS IN**
2 **MR. KASPER'S REBUTTAL TESTIMONY?**

3 A. Yes. On Page 8, Line 11, Mr. Kasper states that bill determinants differ from
4 those referenced in Exhibit Regs. § 53.53 Filing Requirement IV-C Attachment 1,
5 Page 1. The bill determinants that MR. Kasper is making reference to involve the
6 quantity of customers that the customer charge is based upon. As stated in my
7 direct testimony on Page 9, the bill determinants were based upon 1,151,636
8 customers with reference to the Company's Exhibit Future 1, Summary of
9 Measures of Value & Rate of Return, D3, Page 2.

10

11 **Q. ON PAGE 9, LINE 1, MR. KASPER PROVIDES A SCHEDULE**
12 **WHICH COMPARES THE RATE PROPOSALS OF PPL, OCA AND OTS**
13 **AS THEY RELATE TO RATE SCHEDULE RS. IS THIS AN**
14 **ACCURATE REPRESENTATION OF THE OTS PROPOSAL?**

15 A. No. The proposed customer charge attributed to OTS is shown to be
16 \$9.07/month. It should be \$8.25/month. The usage rate charge for the first 800
17 kWh should be \$0.01982/kWh instead of \$0.02056/kWh and that all kWh over
18 800 kWh should be \$0.01760/kWh instead of the \$0.01824/kWh.

1 Q. MR. KASPER STATES THAT ONE OF HIS RATE DESIGN
2 OBJECTIVES FOR RATE SCHEDULE RS WAS TO ADDRESS THE
3 COSTS FOR SERVING CUSTOMERS WHO USE LESS THAN 200 KWH
4 PER MONTH. FOR THIS REASON, 200 KWH WAS INCLUDED IN
5 THE PROPOSED CUSTOMER CHARGE OF \$12.20. DO YOU AGREE
6 WITH THIS PROPOSAL?

7 A. No. Although Mr. Kasper makes reference to low usage customers not paying
8 their proportionate share of the fixed costs required to serve a typical residential
9 customer, including distribution usage charges into the customer charge is not an
10 appropriate way to address this matter. In fact, the Commission has eliminated
11 usage or minimum service from the customer charge in other utility industries,
12 such as water utilities. Including 200 kWh of distribution usage into the
13 customer charge would be contrary to the Commission's recent findings.
14 According to Mr. Kasper's Statement No. 6-R, Attachment 1, 10.49% of all
15 residential bills indicate that the usage is less than 200 kWh per year, with the
16 remaining 89.51% showing usage in an excess of 200 kWh. To change the
17 residential rate design of approximately 90% of residential customers because a
18 small minority of residential customers have limited usage of less than 200 kWh
19 is not the appropriate approach to take. It is proper to address any perceived
20 shortfalls resulting from lower use through the distribution usage charges rather
21 than in the customer charges. The purpose of the customer charge, as stated
22 in my direct testimony, is to recover customer related costs such as meter

1 reading, billing, collection, accounting, metering equipment and service
2 connections. For these reasons I believe that the customer charge should
3 exclude any distribution usage in its charge.
4

5 **Q. ARE THERE ANY OTHER ISSUES YOU WISH TO ADDRESS IN MR.**
6 **KASPER'S REBUTTAL TESTIMONY?**

7 A. Yes. Mr. Kasper states that the OTS proposal to increase rates for Rate
8 Schedule RTS (Residential Thermal Service) is too large and would compromise
9 the Company's objective to keep the increase for the majority of its customers at
10 less than 10%, but acknowledges that this rate schedule is not producing sufficient
11 revenues (Mr. Kasper Statement No. 6-R, Page 13, Line 16). I believe that the
12 minimal revenue increase proposed by the Company is insufficient for a service
13 whose historic rate of return has been negative. Even with the Company's
14 proposed revenue increase for this service, the improvement in the rate of return
15 moves from a -3.95% to only -3.21%. In this instance, the Company should have
16 deviated from its self imposed, less than 10% increase in rates due to the negative
17 return for this service. Although the Company states that it plans on rectifying this
18 revenue shortfall for this service over time, there needs to be significant
19 improvement beginning with this proceeding. I believe that a revenue increase to
20 the level where there is a 0% rate of return, as proposed in my direct testimony, is
21 a reasonable first step and is fair to other customers.

1 Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

2 A. Yes.

OTS Statement No. 6-R
Witness: Gary L Yocca
Date: July 27, 2004

DOCUMENT

8-12-04 JES

w/EXH 6R

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Includes
OTS
Exhibit 6R

Docket No. R-00049255

DOCKETED
AUG 18 2004

Rebuttal Testimony

of

Gary L. Yocca

Office of Trial Staff

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SECRETARY'S BUREAU

Concerning:

Distribution and Transmission Revenue

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

A. My name is Gary L.Yocca. My business address is P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Office of Trial Staff as a Fixed Utility Financial Analyst Supervisor.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. WHAT ARE YOUR DUTIES AS A TECHNICAL SUPERVISOR IN THE OFFICE OF TRIAL STAFF?

A. My current duties include supervision of a group of engineers who are responsible for the engineering, rate structure, revenue, quality of service, rate base and other issues that come before the Office of Trial Staff's Technical Division.

1

2 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

3 A. The purpose of my testimony is to address rate structure and rate making
4 issues presented in the Direct Testimony of Stephen J. Baron on behalf of
5 the PP&L Industrial Customer Alliance (“PPLICA”) in the instant PPL
6 Electric Utilities Corporation (“PPL”) base rate proceeding.

7

8 **Q. WHAT ARE YOUR ISSUES RELATED TO MR. BARON’S**
9 **TESTIMONY?**

10 A. I will address is Mr. Baron’s recommendation regarding the allocation of
11 the distribution and transmission revenue requirement increase in this
12 proceeding.

13

14 **Q. WHAT IS MR. BARON PROPOSAL CONCERNING**
15 **TRANSMISSION REVENUE?**

16 A. Mr. Baron is proposing to change the proposed TSC from an energy-based
17 rate to one that is dependent on both energy and demand.

18

19 **Q. WHAT IS MR. BARON’S PROPOSAL CONCERNING**
20 **DISTRIBUTION REVENUE?**

21 A. Table 6 on page 42 of PPLICA Statement No. 1 summarizes his proposed
22 re-allocation of PPL’s proposed distribution revenue increase.

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Q. WHAT IS THE NET EFFECT ON THE RESIDENTIAL CLASS OF PPLICA'S PROPOSALS?

A. The net effect on the residential class would be to increase its revenue requirement by approximately \$184,693,000 for both distribution and transmission-related services. This is an increase of approximately \$77,874,000, or 72.94% over PPL's proposed revenue increase for that class of approximately \$106,819,000 (See OTS Exhibit No 6-R, Schedule 1, Line 8).

Q. WHAT IS THE BASIS FOR MR. BARON'S PROPOSALS?

A. The basis for his proposals is to decrease the alleged subsidies for both distribution and transmission-related services. His goal for the distribution service rate is to move the rates of return for each rate class closer to the system average rate of return. His proposal for the TSC is based on changing how each rate schedule is charged based on how PPL is billed by PJM for transmission services under the PJM Open Access Transmission Tariff ("OATT").

I. Transmission Revenue

Q. WHAT IS MR. BARON'S PROPOSAL CONCERNING TRANSMISSION REVENUE?

1 A. He is proposing to change the proposed TSC from an energy-based rate to
2 one that is dependent on both energy and demand. Under his proposal,
3 summarized on page 28 of PPLICA Statement No. 1, the residential classes
4 will see increases in the proposed TSC of \$44,886,000. This represents an
5 increase of \$19,598,000 over PPL's proposed increase of \$25,288,000. It
6 also represents 78.36% of the total proposed increase to the transmission
7 rate of \$57,282,000 (See OTS Exhibit No. 6-R, Schedule 1, Line 4).

8

9 **Q. WHY IS MR. BARON RECOMMENDING CHANGES TO THE**
10 **TSC?**

11 A. As I stated above, he is proposing to eliminate the alleged subsidy in the
12 TSC by charging each customer class a rate based on both usage and
13 demand.

14

15 **Q. WHAT IS THE BASIS FOR MR. BARON'S POSITION?**

16 A. Mr. Baron believes that since 73% of the PJM charges for transmission
17 service are based on demand, and only 27% of the PJM charges are usage
18 based, it is unfair for PPL to charge customers for transmission service
19 based solely on usage (PPLICA Statement No. 1, pages 16-17).

20

21 **Q. HOW IS MR. BARON PROPOSING TO RECTIFY THIS ALLEGED**
22 **INEQUITY?**

1 A. Mr. Baron is proposing to re-allocate the recovery of the PJM transmission
2 charges as shown on PPLICA Statement No.1, Table 3. As I understand his
3 proposal, some customers would be charged on a kWh basis, and some on a
4 demand and kWh basis (PPLICA Statement No. 1, Pages 24-26).

5

6 **Q. DO YOU AGREE WITH MR. BARON'S PROPOSAL TO RE-**
7 **ALLOCATE THE TRANSMISSION CHARGES AMONG THE**
8 **VARIOUS CLASS AS SHOWN ON TABLE 3?**

9 A. No.

10

11 **Q. WHAT DO YOU RECOMMEND?**

12 A. I recommend that the TSC as proposed by PPL be approved on a kWh
13 basis.

14

15 **Q. WHY DO YOU RECOMMEND THAT MR. BARON'S PROPOSAL**
16 **BE DENIED?**

17 A. Mr. Baron is basing his recommendation to re-allocating the transmission
18 charges without considering the overall cost of providing each of these
19 customers with transmission service as determined by the Public Utility
20 Commission.

21

1 **Q. DID THE COMPANY SUBMIT A COST OF SERVICE STUDY**
2 **THAT WOULD ALLOW THE COMMISSION TO DETERMINE**
3 **THE OVERALL COST OF PROVIDING TRANSMISSION**
4 **SERVICE FOR EACH CLASS?**

5 A. No. When requested during discovery by OTS to provide a fully-allocated
6 cost of service study including both distribution and transmission-related
7 accounts, the Company claimed that the costs are separately recovered
8 through FERC jurisdictional rates, and would not have a material effect on
9 the results of the cost of service study. Therefore, it was never provided
10 (See OTS Exhibit No. 6-R, Schedule 2).

11

12 **Q. WHY SHOULD THE COMMISSION REVIEW A FULLY-**
13 **ALLOCATED COST OF SERVICE STUDY BEFORE RE-**
14 **ALLOCATING TRANSMISSION RATES?**

15 A. A fully-allocated cost of service study will show the relative rate of return
16 for each customer class. It will also show whether the revenue received
17 from each class is above or below the corresponding cost of providing
18 distribution and transmission service for that class. With this information,
19 the Commission could properly determine if the transmission rates are
20 properly set to recover the corresponding cost of providing transmission
21 service for each class.

1 It must be remembered that even though the Federal Energy
2 Regulatory Commission (“FERC”) sets the transmission charges through
3 the OATT, this Commission has the final say on how those charges are
4 recovered by PPL’s customers. The lack of a fully-allocated distribution
5 and transmission (“T & D”) cost of service study to use as a guide makes
6 this task very difficult. The Commission has no way of knowing what the
7 true subsidies are in this proceeding. The Commission should be very
8 careful before making wholesale changes to the Company’s proposed rates.

9
10 **II. Distribution Revenue**

11 **Q. WHAT IS MR. BARON’S RECOMMENDATION CONCERNING**
12 **DISTRIBUTION RATES?**

13 **A.** He recommends reducing the alleged current dollar subsidies to the
14 residential class in distribution rates by 50% in this proceeding. He further
15 recommends adjusting rates in a manner such that 25% of the alleged,
16 remaining subsidies are removed in each of the successive years after the
17 first year of the authorized increase approved in this case. He claims that
18 by using this approach, all the remaining subsidies will be removed by the
19 third year that the new rates are in effect. What he appears to be proposing
20 is what is referred to in the telecommunications industry as a “revenue
21 neutral rate rebalancing.” (PPLICA Statement No. 1, pages 11 and, 13-31).

1 Table 6 on page 42 of PPLICA Statement No. 1 summarizes his
2 proposed re-allocation of PPL's proposed distribution revenue increase. He
3 is proposing to allocate \$139,807,000, or 86.12% of PPL's proposed
4 revenue increase of \$162,345,000 to the residential class. This is an
5 increase of \$58,276,000, or 71.48% over the Company's proposed increase
6 of \$81,531,000 (See OTS Exhibit No. 6-R, Schedule 1, Line 7). The two
7 commercial rate schedules will see increases totaling \$13,453,000 under his
8 proposal. This represents a decrease of \$51,663,000, or 79.34% from the
9 Company's proposed rate increase to the GS-1 and GS-3 rate schedules of
10 \$65,116,000. The SL/AL rate schedules will also see significant rate
11 increases under his proposal. The increase under PPLICA's proposal will
12 be \$7,640,000, or 363.81% greater than the Company's proposed increase
13 of \$2,100,000. The remaining rate schedules will see either smaller
14 increases than proposed by the Company or rate decreases.

15
16 **Q. WHAT SPECIFIC ANALYSIS IS MR. BARON RELYING ON TO**
17 **SUPPORT HIS RECOMMENDATION?**

18 **A.** When looking at the distribution-related rates, Mr. Baron is relying on the
19 cost of service study presented by the Company to determine the alleged
20 subsidies. The specific subsidies that Mr. Baron is proposing to eliminate
21 are shown on Table 5 of PPLICA Statement No. 1 (See page 37).

22

1 Q. WHAT IS WRONG WITH RELYING ON THE COST OF SERVICE
2 STUDY AS FILED BY THE COMPANY?

3 A. Mr. Baron's proposal does not consider the effect on the alleged subsidy if
4 the Commission makes any changes to the Company's revenues, expenses,
5 return dollars and cost of service calculation in this proceeding.

6 Additionally, as I stated above, the Company has not provided a fully-
7 allocated T & D cost of service study which can be used as the basis for
8 allocating proposed revenues among the various customer classes.

9

10 Q. CAN YOU EXPLAIN HOW CHANGES TO THE COMPANY'S
11 REVENUES, EXPENSES, RETURN DOLLARS WILL AFFECT
12 THIS ALLEGED PRESENT RATE SUBSIDY OF \$57,223,000 THAT
13 THE RESIDENTIAL CUSTOMERS RECEIVE?

14 A. Yes. Any changes in these items affect the overall rate of return by class
15 since the cost of service study includes all the components that the
16 Commission may adjust. For example, OTS witness Kubas has proposed
17 that present revenue for the residential class be increased by ~~\$15,109,000~~ \$3,065,000
18 (See OTS Statement No. 3). If the Commission approves all or part of Mr.
19 Kubas' recommendation, this additional revenue will be added to the
20 residential rate class. This additional revenue will reduce the alleged
21 \$57,223,000 subsidy at present rates shown on PPLICA Table 5 that the RS
22 and RTS rate schedules receive. Adjustments to the Company's proposed

1 expenses and rate of return will also have an impact on any interclass
2 subsidies. Another area is the cost of service study itself. The Office of
3 Consumer Advocate (OCA) has provided direct testimony challenging the
4 assumptions in and the result of the Company's cost of service study (See
5 OCA Statement 4, Page 3). When the Commission finally decides this
6 case, the alleged \$57,223,000 subsidy shown on Table 5 of PPLICA
7 Statement No. 1 will be different.

8
9 **Q. WILL THE COMMISSION KNOW WHAT THE ALLEGED**
10 **SUBSIDY BY CLASS IS AT THE CONCLUSION OF THE CASE?**

11 A. No. Utilities are not required to file a "Compliance" cost of service study
12 at the end of the proceeding at the Commission approved rates, and Mr.
13 Baron did not propose that PPL provide such a filing. The alleged
14 subsidies that the RS class receives after rates are established in this case
15 will be less than the subsidies determined by Mr. Baron. Based on this
16 conclusion, I believe it would be unfair to RS customers to increase their
17 rates the additional \$86,887,000 (including the proposed rate rebalancing)
18 proposed by Mr. Baron.

19
20 **III. Rebalancing Rates**

21 **Q. WHAT IS MR. BARON'S PROPOSAL CONCERNING**
22 **REBALACING RATES?**

1 A. Mr. Baron is proposing that rates be rebalanced two times, the first
2 rebalancing would occur one year after the conclusion of this case, and a
3 second rebalancing would occur one year after that. He believes that
4 “revenue neutral rate rebalancings” are necessary to eliminate the subsidies
5 that exist between the various rate classes (PPLICA Statement No. 1, page
6 40). As shown on Table 5 of Mr. Baron’s testimony, his rate rebalancing
7 would increase rates for residential and street lighting customers, and
8 decrease rates for the commercial and most industrial customers.

9

10 **Q. DO YOU AGREE WITH MR. BARON’S PROPOSAL TO**
11 **REBALANCE RATES?**

12 A. No.

13

14 **Q. WHY DO YOU RECOMMEND THAT MR. BARON’S PROPOSAL**
15 **BE DENIED?**

16 A. There are several reasons. First, there are no provisions in the Public
17 Utility Code that allow electric utilities to rebalance rates outside of a base
18 rate case. Second, I believe that this proposal only addresses one issue,
19 revenues, rather than all issues that comprise the rate making process.
20 Looking only at one issue is sometimes considered “single issue rate
21 making,” which typically is not allowed. Third, Mr. Baron’s proposal does
22 not consider the effect on the alleged subsidy if the Commission makes any

1 changes to the Company's revenues, expenses, return dollars and cost of
2 service calculation in this proceeding.

3
4 **Q. LOOKING AT YOUR FIRST CONCERN, DOES MR. BARON CITE**
5 **ANY PUBLIC UTILITY CODE THAT ALLOWS ELECTRIC**
6 **UTILITIES TO REBALANCE RATES?**

7 A. No.

8
9 **Q. IS THERE A PROVISION IN THE PUBLIC UTILITY CODE THAT**
10 **DOES ALLOW ONE TYPE OF UTILITY TO REBALANCE**
11 **RATES?**

12 A. Yes. Counsel advised me that "revenue neutral rate rebalancings" only
13 apply to utilities under an alternative form of regulation. Currently, only
14 telephone companies are governed under an alternative form of regulation
15 as described in 66 Pa. C. S. A. § 30 (Chapter 30).

16
17 **Q. ARE ELECTRIC COMPANIES INCLUDED IN CHAPTER 30?**

18 A. No. Only telephone companies are described in Chapter 30. Only
19 Telephone companies may implement revenue neutral rate rebalancing
20 under 66 Pa. C. S. A. § 3006. Counsel also advises me that it is, therefore,
21 reasonable to assume that the Legislature did not intent Chapter 30 to apply
22 to other utilities. The Pennsylvania Rules of Statutory Construction, at 1

1 Pa. C.S. §1924, provides the necessary guidance to determine that the
2 Legislature intended to provide telephone Companies, and only telephone
3 companies, the streamlined form of regulation described in Chapter 30:
4

5 **§1924. Construction of titles, preambles, provisos,**
6 **exceptions and headings.**

7 The title and preamble of a statute may be considered
8 in the construction thereof. Provisos shall be construed
9 to limit rather than to extend the operation of the
10 clauses to which they refer. **Exceptions expressed in a**
11 **statute shall be construed to exclude all others.** The
12 headings prefixed to titles, parts, articles, chapters,
13 sections and other divisions of a statute shall not be
14 considered to control but may be used to aid in the
15 construction thereof.

16 [Emphasis Added.]

17 Again, counsel advises me that the correct interpretation is, therefore, that
18 the existing Chapter 30 was intended by the Legislature to provide the
19 necessary statutory authority to allow telephone Companies the ability to be
20 governed under an alternative form of regulation. Because neither Chapter
21 30 nor any other statutory provision existed to grant such authority, only
22 the specifically identified utility type, i.e., telephone companies, were to be
23 granted such alternative regulation, other utility types were excluded.
24 Stated another way, had the Pennsylvania Legislature intended to grant
25 authority to electric utilities to implement rate rebalancing outside a base
26 rate case, it would have specifically identified electric utilities in either

1 Chapter 30 or some subsection of Chapter 30. Since electric utilities are
2 not specifically identified, the appropriate statutory presumption is that the
3 Legislature intended not to grant the same rate hike mechanism to them.

4 **Q. LOOKING AT YOUR SECOND CONCERN, WHAT SPECIFIC**
5 **CHANGES IN THE ALLEGED SUBSIDIES DOES MR. BARON**
6 **PROPOSE?**

7 A. Mr. Baron's is proposing that the alleged present dollar subsidies listed on
8 PPLICA Table 5 be reduced by 50%. Mr. Baron proposes that the current
9 alleged residential subsidy of approximately \$57,223,000 be reduced by
10 50%. This would be approximately \$28,612,500 ($\$57,223,000 / 2 =$
11 $\$28,612,500$). However, according to PPLICA Exhibit SJB-10, Mr. Baron
12 is proposing an increase to the residential rate classes ^{revenues by} ~~of~~ \$58,276,000 (See
13 PPLICA Statement No. 1, page 40, Lines 14 – 21), which amount is greater
14 than the alleged present rate subsidy stated above. Therefore, it is not quite
15 clear what his recommendation really is in this proceeding. Based on my
16 understanding of his testimony, Mr. Baron is proposing to more than
17 eliminate the present dollar subsidy to the residential class.

18
19 **Q. HOW MUCH MORE DO RESIDENTIAL REVENUES HAVE TO**
20 **INCREASE IN ORDER TO ELIMINATE THE REMAINING**
21 **ALLEGED RESIDENTIAL CLASS SUBSIDY?**

1 A. Mr. Baron proposes that RS rates be increased in each of the two
2 subsequent years to eliminate the remaining 50% of the alleged subsidy
3 (PPLICA Statement No. 1, page 40). Since there is no remaining present
4 rate subsidy as described above, his proposal should be moot. If his
5 testimony is that the total alleged subsidy, at proposed rates be eliminated,
6 then based on my analysis, that amount is approximately \$28,611,000.
7 Under these conditions, this means that he is proposing to increase
8 residential rates by $(\$28,611,000/2)$ \$14,305,500 a year in each of the two
9 years following the approval of rates in this proceeding. As discussed in
10 detail above, this should not be allowed.

11

12 **Q. WHY DO YOU BELIEVE THAT MR. BARON PROPOSAL WOULD**
13 **BE SINGLE ISSUE RATEMAKING?**

14 A. Under his proposal, the remaining alleged subsidy at the proposed rate
15 level would be \$28,611,000, in 2005. He believes that this \$28,611,000
16 should be reduced to zero ~~in~~^{by} 2007. Mr. Baron's proposal assumes that the
17 alleged subsidy remains constant over a three-year period. This is
18 obviously not the case, since revenues, expenses, taxes and rate base
19 change will change from year to year. Mr. Baron has failed to describe
20 how changes in these items would be considered in his proposal.

21

1 **Q. WHAT COULD HAPPEN IF THESE ITEMS ARE NOT**
2 **CONSIDERED?**

3 A. If these items are not considered, the residential customer's rates could
4 potentially become so high that they actually pay a subsidy, rather than
5 receive one. In other words, Mr. Baron's proposal could actually
6 "overcorrect" for the alleged subsidy that he identifies.

7

8 **Q. LOOKING AT YOUR THIRD CONCERN, WILL THE**
9 **COMMISSION KNOW WHAT THE ALLEGED SUBSIDY BY**
10 **CLASS IS AT THE CONCLUSION OF THE CASE?**

11 A. No. As described above, utilities are not required to file a "Compliance"
12 cost of service study at the end of the proceeding at compliance rates, and
13 Mr. Baron did not propose that PPL provide such a filing. The subsidy that
14 the residential class receives after rates are established in this case will be
15 less than the \$28,611,000 described above. Based on this conclusion, I
16 believe it would be unfair to residential customers to increase their rates by
17 that amount without considering changes to the cost of service study as a
18 result of the Commission's action in this proceeding.

19

20 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

21 A. Yes, it does.

22

Gary L. Yocca
P.O. Box 3265
Harrisburg, PA 17105-3265
(717)783-6178

Career Summary: *Fixed Utility Financial Analyst Supervisor* with twelve years of experience in supervising technical experts in the Commission's Office of Trial Staff, and with twenty eight years of experience in analyzing economic, engineering, financial, quality of service and rate structure data in major gas, electric, telecommunications, water, sewer and steam heat cases. I have presented expert testimony, which covers a wide range of technical issues, in numerous proceedings before the Commission.

Fixed Utility Financial Analyst Supervisor **Current**
PENNSYLVANIA PUBLIC UTILITY COMMISSION
OFFICE OF TRIAL STAFF
OTS TECHNICAL STAFF
SUPERVISOR - ENGINEERING, REVENUE, RATE STRUCTURE AND QUALITY OF SERVICE HARRISBURG, PA

As a result of the creation of the Bureau of Fixed Utility Services and the reorganization of the Office of Trial Staff, effective April 1, 1996 my supervisory responsibilities were changed to include the areas of Engineering, Revenue and Rate Structure for all fixed utility types. During the course of formal and informal investigations personnel under my direction are responsible for reviewing and presenting recommendations regarding tariff rate schedules, tariff rules and regulations, measures of value claims, revenue annualizations, depreciation claims, fuel purchasing practices and economic analyses. They are also responsible for reviewing all pertinent supporting information such as cost of service studies, bill frequency analyses, proofs of revenue, depreciation studies, water quality test results and formal complaints.

Fixed Utility Financial Analyst Supervisor **2 Years**
PENNSYLVANIA PUBLIC UTILITY COMMISSION
OFFICE OF TRIAL STAFF
TELECOMMUNICATIONS/WATER DIVISION
RATE STRUCTURE/ENGINEERING SECTION HARRISBURG, PA

From March of 1994 to March of 1996 my responsibilities included the supervision and direction of the Rate Structure/Engineering Section, and assisting the Legal Division of the Office of Trial Staff in all aspects of rate structure, rate base and quality of service litigation in water, sewer and telecommunications filings.

Fixed Utility Financial Analyst Supervisor **2 Years**
PENNSYLVANIA PUBLIC UTILITY COMMISSION
OFFICE OF TRIAL STAFF
ENGINEERING AND RATE DESIGN DIVISION
ANALYSIS SECTION HARRISBURG, PA

I was named Section Chief of the Analysis Section of the Engineering and Rate Design Division in February 1992. My responsibilities were essentially the same as those above, except that my section was responsible for the rate structure and engineering aspects of all utility types including gas, electric and steam heat.

Fixed Utility Financial Analyst 3

5 ½ Years

PENNSYLVANIA PUBLIC UTILITY COMMISSION
OFFICE OF TRIAL STAFF
ENGINEERING AND RATE DESIGN DIVISION

HARRISBURG, PA

I performed the functions of an expert witness in major water, steam heat, gas and electric cases before the Pennsylvania Public Utility Commission from September 1986 to February 1992. My testimony covered many issues ranging from cost of service and rate design to natural gas transportation issues.

Fixed Utility Financial Analyst 3

3 ½ Years

PENNSYLVANIA PUBLIC UTILITY COMMISSION
BUREAU OF RATES
ELECTRIC DIVISION

HARRISBURG, PA

I was an expert witness during the period from December 1982 until August 1986. I addressed various issues including rate structure, revenues and sales levels. I was also responsible for analyzing and making recommendations on numerous electric tariff filings including economic development rates.

Bureau of Rates Liaison to the Federal Energy Regulatory Commission (FERC)

6 Months

PENNSYLVANIA PUBLIC UTILITY COMMISSION
BUREAU OF RATES
ELECTRIC DIVISION

HARRISBURG, PA

Concurrently with the above duties, for a six-month period in 1982 and 1983, I participated in hearings and settlement conferences before FERC on natural gas transmission matters.

Public Utility Analyst 3

3 ½ Years

PENNSYLVANIA PUBLIC UTILITY COMMISSION
BUREAU OF RATES
GAS DIVISION

HARRISBURG, PA

From February 1979 to November 1982, my main role was to perform the duties of an expert witness on revenue and expense issues in major gas utility rate cases. The issues that I addressed ranged from normalized sales levels to annualizations of claimed expenses.

Public Utility Analyst 1 and 2

3 Years

PENNSYLVANIA PUBLIC UTILITY COMMISSION
BUREAU OF RATES AND RESEARCH
ENERGY DIVISION

HARRISBURG, PA

After joining the Pennsylvania Public Utility Commission in February 1976, I performed the duties of a Public Utility Analyst 1 and 2. For the first three years I worked mainly on major gas and electric cases with increasing levels of responsibility in the areas of revenues and expenses.

Production Analyst

5 Years

UNITED STATES ARMY SECURITY AGENCY
USASAFS BERLIN

BERLIN, GERMANY

During my final three years in the U.S. Army, I performed the duties of a Production Analyst and a Senior Voice Intercept Operator - German Language Transmissions at the Army Security Agency's Field Station in Berlin, Germany. I prepared operational reports to the National Security Agency and developed procedures to analyze the operational efficiency of the unit. As a Senior Voice Intercept Operator, I had supervisory responsibility over thirteen other Voice Intercept Operators.

Education

Master of Science in Business Administration, Cum Laude
BOSTON UNIVERSITY

1977
BOSTON, MA

Major: Boston University's MBA Program focused on Business Management, and included courses in Economics, Accounting, Management and Statistics.

Bachelor of Science

THE PENNSYLVANIA STATE UNIVERSITY

1969
UNIVERSITY PARK, PA

Major: My major was Ceramic Science in the College of Earth and Mineral Sciences. The program focused on the engineering and chemistry of non-organic, non-metallic materials that are generally formed at and are able to withstand high temperatures.

**Numerous Conferences and Seminars Concerning Public Utility
Regulation, Economics and Management**

1976 to Present
VARIOUS LOCATIONS

I have attended over 90 conferences and seminars since I began employment with the Pennsylvania Public Utility Commission. A detailed listing is available.

Testimony

The following list provides an index of the natural gas distribution, electric power, telecommunications, steam heat, sewer and water service utility cases in which I have presented expert testimony before the Pennsylvania Public Utility Commission.

<u>COMPANY</u>	<u>DOCKET NO.</u>
. APOLLO GAS COMPANY	R-79100972
. BELL ATLANTIC-PENNSYLVANIA, INC.	R-00943008
. BOROUGH OF SCHUYLKILL HAVEN	R-00943156
. CHARTIERS NATURAL GAS COMPANY, INC.	R-891283
. COLUMBIA GAS OF PENNSYLVANIA, INC.	R-78120714
	R-822042
. Commonwealth Telephone Company	P-00961024
. CONESTOGA TELEPHONE & TELEGRAPH CO.	I-00920015
. DUQUESNE LIGHT COMPANY	R-842583
	R-850021
	R-860378
EQUITABLE GAS COMPANY	R-870666
	R-880971
	R-891238
	R-901595
	R-911925
	R-912164
	I-900009
. EQUITABLE GAS - ENERGY COMPANY	R-880941
	R-901870
. FRONTIER COMMUNICATIONS OF BREEZEWOOD, INC., ET. AL.	P-00951005
. Glen Alsace Water Company	R-00922319
. Ironton Telephone Company	P-00971182
. Lake Latonka Water Company	R-870687
. Lemont Water Company	R-00932673
. LP Water and Sewer Company	A-211770/A-230242/G-910255
. Metropolitan Edison Company	R-842770
	P-920567

Testimony (cont.):

<u>COMPANY</u>	<u>DOCKET NO.</u>
National Fuel Gas Distribution Corporation	R-79090956
	R-811600
National Utilities, Inc.	R-00953416
North Penn Gas Company	R-80111375
Pennsylvania American Water Company	R-911909
Pennsylvania Electric Company	R-822250
	R-842771
	R-860413
	R-880979
	P-920567
Pennsylvania Gas & Water Company - Gas	R.I.D. 296, F-2
Pennsylvania Gas & Water Company - Water	R-00922482
Pennsylvania Power Company	R-850267
Pennsylvania Power & Light Company	I-830374
	R-842651
Philadelphia Electric Company - Gas	R-8111719
Philadelphia Gas Works	R-00038173
Philadelphia Suburban Water Company	R-870840
The Peoples Natural Gas Company	R-00922180
	R-00922206
Western Pennsylvania Water Company	R-870825

DOCUMENT

OTS Exhibit No. 6-R
Witness: Gary L. Yocca
Date: July 27, 2004

8-10-04 JES
HBU

DOCKETED

AUG 18 2004

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PPL ELECTRIC UTILITIES CORPORATION

Docket No. R-00049255

Exhibit to Accompany the
Rebuttal Testimony

of

Gary L. Yocca

Office of Trial Staff

RECEIVED

AUG 17 2004

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Concerning:

Distribution and Transmission Revenue

PPL Electric Utilities
Docket R-00049255
Comparison of PPL and PPLICA Proposed Revenue

Transmission			
(A)	PPL Proposed (B)	PPLICA Increase (C)	PPLICA Proposed (D)
1 RS	\$23,505,000	\$19,001,000	\$42,506,000
2 RTS	\$1,773,000	\$590,000	\$2,363,000
3 RTD	\$10,000	\$7,000	\$17,000
4 Total Dist.	<u>\$25,288,000</u>	<u>\$19,598,000</u>	<u>\$44,886,000</u>
Distribution			
	PPL Proposed	PPLICA Increase	PPLICA Proposed
5 RS	\$80,963,000	\$52,178,000	\$133,141,000
6 RTS	\$568,000	\$6,098,000	\$6,666,000
7 Total Dist.	<u>\$81,531,000</u>	<u>\$58,276,000</u>	<u>\$139,807,000</u>
8 TOTALS	<u>\$106,819,000</u>	<u>\$77,874,000</u>	<u>\$184,693,000</u>

J. M. Kleha

**PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set 13,
Dated May 4, 2004**

Docket No. R-00049255

Q.OTS-RS-56. Redo the cost of service study incorporating all transmission-related accounts. Provide all supporting schedules.

A.OTS-RS-56 There are two separate transmission-related issues raised by this question. First, in this filing, PPL Electric proposes to recover through the Transmission Service Charge all transmission service charges that it pays to PJM under the Open Access Transmission Tariff in order to provide POLR service to retail customers. These transmission service charges are billed by PJM and, under PPL Electric's proposal, would be collected from POLR customers on a uniform cents per kwh basis without any element of profit. Inclusion of this operating expense in the class cost allocation study would have no material effect on class rates of return and there is, therefore, no need to rerun the cost allocation study to reflect this operating expense.

Second, and separately from the Transmission Service Charge issue, PPL Electric provides transmission service to certain wholesale customers and makes its transmission facilities available to PJM. The cost of this service is recovered through rates filed with and approved by the FERC. PPL Electric has appropriately excluded these costs from its Pennsylvania jurisdictional cost allocation study because these costs are separately recovered through FERC jurisdictional rates.

J. M. Kleha

**PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set 17,
Dated June 1, 2004**

Docket No. R-00049255

- Q.OTS-RS-77.** With reference to Exhibit JMK 2, Page 36, the Company shows the rate base items assigned to the various rate schedules only for the Pennsylvania jurisdiction (distribution).
- A.** Does the Company have the data in the same format for the transmission system? If available, please provide this data.
- B.** Historically, how was this data allocated to the various customer classes?
- A.OTS-RS-77.**
- A.** No.
- B.** Historically, PPL Electric has used, and traditionally this Commission has accepted, the monthly peak responsibility demand methodology, or the 12 coincident peak method (12 CP), to allocate the Company's transmission plant in service. See the response to Question OTS-RS-56 of Interrogatories of the Office of Trial Staff, Set 13, dated May 4, 2004.