PPLICA Statement No. 4

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AUG 1 6 2007

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

DOCUMENT FOLDER

SURREBUTTAL TESTIMONY

OF

STEPHEN J. BARON

DOCKETED

SEP 7 - 2007

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

August 2007

RECEIVED

AUG 1 7 2007

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	**Docket No. R-00072155**
	)	
PPL Electric Utilities Corporation	)	

SURREBUTTAL TESTIMONY OF STEPHEN J. BARON

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 Testimony, Supplemental Direct Testimony and Rebuttal Testimony.

Q. What is the purpose of your Surrebuttal Testimony?

A. I am responding to the Rebuttal Testimony of witnesses for PPL Electric Utilities Corporation ("PPL" or "Company") and the Office of Consumer Advocate ("OCA"). With regard to PPL, I will respond to the Rebuttal Testimony of Mr. Douglas Krall and Mr. Oliver Kasper on the apportionment of the revenue increase in this case and on the Company's proposed modifications to Tariff Rule 4A.

With regard to the OCA, I will respond to the Rebuttal Testimony of Mr. Richard Galligan on class cost of service and the apportionment of the approved revenue increase to rate schedules.

Response to PPL Rebuttal Witnesses

Q. Do you have any response to the Rebuttal Testimony of PPL witness Douglas Krall regarding the apportionment of the total revenue increase to rate schedules?

A. Yes. Mr. Krall addresses the PPLICA proposed apportionment of the revenue increase on the basis of a "50% reduction in the dollar subsidies paid or received" by each rate schedule. The Company continues to recommend a method that moves rate schedules' rates of return "one-half of the way to full cost of service." Though, at the end of two additional rate cases (the Company's proposed time table), the results of the PPL method and the PPLICA method should be identical, I continue to recommend the use of a dollar subsidy reduction approach because this method provides a direct reduction in the rate disparities that exist in PPL's distribution rates, consistent with the Commonwealth Court's decision in Lloyd. However, because the dollar differences between the revised PPL proposal and my preferred 50% dollar subsidy reduction approach are small, PPLICA can accept PPL's revised proposal with one revision that would more reasonably reduce the subsidies paid by rate schedules IS-P and IS-T. As shown in Table 1 below, Rate Schedules IS-P and IS-T will continue to have rates of return well in excess of other large customer rates under the Company's proposal. This problem can be corrected with a relatively small dollar adjustment to the Company's proposed rate schedule increases.

Q. Would you please describe the revision that you recommend to the Company's revenue apportionment?

A. Yes. The Company is recommending the rate schedule increases shown in Table 1 below. Also shown in Table 1 are the relative rates of return for each rate schedule at PPL proposed rates.[1] These increases and decreases reflect the Company's proposal to move rates towards full cost of service, subject to a constraint that no rate schedule receives an increase greater than two times the system average.

Table 1
PPL Proposed Increases

Rate Class	Revenue Increase	Percent Increase	Rate of Return Index
RS, RTD	72,507	18.76%	84.10%
RTS	999	25.03%	-25.03%
GS-1, BL	198	0.27%	150.06%
GS-3, IS-1	(932)	-0.85%	154.80%
LP-4	(339)	-1.16%	155.63%
ISP	(125)	-7.02%	191.70%
LP-5	5	0.43%	146.50%
IST	(89)	-15.78%	285.65%
LP-6	9	25.00%	-36.54%
LPEP	(7)	-2.10%	165.12%
GH	541	8.38%	116.84%
SL/AL	4,213	24.05%	45.43%
L5-S	(0)	0.00%	100.95%
Total	76,980	12.19%	

[1] Table 1 is a summary of information provided in Mr. Kasper's Attachment 3, Appendix A of his Rebuttal Testimony.

As can be seen from this summary, the relative rates of return for Rate Schedules IS-P and IS-T at PPL's proposed rates remain substantially above the level for other customer classes that are paying rates above cost of service. To address this problem, the proposed decreases for Rate Schedules IS-P and IS-T should be further decreased so that their relative rates of return are no greater than 165%, which is the relative rate of return for Rate Schedule LPEP, the next highest rate of return.

Q. **Have you developed a schedule showing the impact of the required adjustment to the Company's revenue apportionment?**

A. Yes. Table 2 below shows the necessary adjustments. In order to bring the relative rates of return (at proposed rates) for Rate Schedules IS-P and IS-T to 165% (a rate of return of 13.91), it is necessary to decrease rate schedule IS-P by an additional $159,000 and Rate Schedule IS-T by an additional $153,000. In keeping with the Company's proposed "2 times the system average increase cap," the additional revenue decreases should be applied to Rate Schedules RS-RDT, which is the only class that is below the system average rate of return and not already at the "2 times system average" constraint. The impact on RS-RDT is to change the increase from PPL's proposed 18.76% to an adjusted 18.84% increase.

Table 2
PPL Proposed Increases

Rate Class	PPL Revenue Increase	Revenue Adjust.	Adjusted Increase	Adjusted % Incr.
RS, RTD	72,507	311	72,818	18.84%
RTS	999		999	25.03%
GS-1, BL	198		198	0.27%
GS-3, IS-1	(932)		(932)	-0.85%
LP-4	(339)		(339)	-1.16%
ISP	(125)	-159	(284)	-15.92%
LP-5	5		5	0.43%
IST	(89)	-153	(242)	-42.89%
LP-6	9		9	25.00%
LPEP	(7)		(7)	-2.10%
GH	541		541	8.38%
SL/AL	4,213		4,213	24.05%
L5-S	(0)		(0)	-0.13%
Total	76,980	0	76,980	12.19%

Q. **Do you have any comments regarding the Company's criticism of your scaleback methodology?**

A. Yes. Mr. Krall opposes the scaleback proposal that I presented in my Direct Testimony on the basis that it would result in residential customers receiving a share of the final rate allowance "meaningfully above the overall increase." As shown in Table 1, PPL itself is proposing a residential increase meaningfully above the average. This, of course, is required to address the large rate disparities in PPL's distribution rates. A scaleback of the Company's requested increase should not be used to disrupt the movement of rates to full cost of service, as proposed by PPL.

The scaleback proposal that I recommended in my Direct Testimony should be used to adjust PPL's proposed apportionment of the approved increase (as modified for the targeted reductions for Rate Schedules IS-P and IS-T that I discussed above). Subject to the "2 times system average increase" constraint, any reductions in PPL's requested overall revenue increase should be used to bring the rates of return for Rate Schedules IS-P and IS-T to the level of Rate Schedule LP-5 and other large customer rates (a rate of return index of above 165). The remaining reduction (from the Company's requested overall increase) should be assigned to rate schedules on the basis of rate base. Allocating the "reduction" on each rate schedule's percentage share of distribution rate base preserves the movement towards full cost of service that underlies the Company's proposal in this case.

Q. Have you reviewed the Rebuttal Testimony of PPL witness Oliver Kasper regarding your concerns on the Company's proposed modifications to Tariff Rule 4A?

A. Yes. In response to the concerns raised by PPLICA in my Direct Testimony on this issue, PPL has clarified its proposed tariff rule change. In general, PPLICA is satisfied with the proposed clarifications that confirm a continued obligation to provide full service to PPL distribution customers taking service at voltages of 69 kV or greater. However, the proposed clarification included in Mr. Kasper's Rebuttal Testimony on page 11, beginning at line 7 [clarification of Tariff Rule 4A(2)] should be further clarified to ensure that PPL's high voltage customers continue to receive non-discriminatory, just and reasonable distribution rates.

The specific addition to Mr. Kasper's proposed clarification language is as follows (additional PPLICA language in bold italics):

> However, this definition does not affect the Company's obligations under the Public Utility Code, Commission regulations and Commission orders to provide safe, reliable and adequate retail electric service to customers taking service at voltages of 69 kV and above, ***and to provide just and reasonable and non-discriminatory rates, terms and conditions of service to such customers.***

With this change (and PPL's other proposed clarifications), PPLICA can accept PPL's proposed Rule 4A modification.

Response to the Office of Consumer Advocate

Q. Have you reviewed the Rebuttal Testimony of OCA witness Richard Galligan in this case?

A. Yes. Mr. Galligan responds to the Direct Testimony of witnesses for the OSBA, the DOD and PPLICA on the issue of PPL's class cost of service study. He continues to defend his recommendation to adopt a Peak and Average methodology to allocate all primary and secondary distribution plant and expenses, except meters and services such that 50% of all primary and common distribution plant and expenses are allocated to rate schedules on the basis of kWh energy and 50% on kW demand. I addressed Mr. Galligan's proposal in my Rebuttal Testimony and continue to strongly oppose an energy allocation methodology to assign fixed, distribution facilities to rate schedules. Mr. Galligan's Rebuttal Testimony does not provide any additional support for his proposed method.

Q. Has Mr. Galligan identified any regulatory commission that has adopted his recommended Peak and Average method for electric distribution cost of service in the past 10 years?

A. No. In his response to PPLICA Set II, Question Numbers 11 and 12, he was asked about regulatory proceedings in which he recommended the Peak and Average methodology for distribution cost allocation. He indicated in his response to Question Number 11 that he recommended the methodology in three proceedings during the past 10 years. These cases included the most recent PPL remand proceeding, a recent Duquesne Light Company proceeding and a Southern Indiana Gas & Electric Company case. All of these cases were settled. Mr. Galligan could not identify a single case in which the Peak and Average method was adopted by a regulator.

Q. Are you familiar with the Duquesne Light Company case and the PPL remand case?

A. Yes. I participated in both of those cases. Though Mr. Galligan is correct that these two cases were settled, the settlements reflected allocations consistent with traditional cost of service methodologies sponsored by the respective utilities.

Q. Does that complete your Surrebuttal Testimony?

A. Yes.

OCA Statement No. 1-Supplemental

Hbg RK AUG 16 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKETED SEP 7 - 2007

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
	)	
	)	
v.	)	DOCKET NO. R-00072155
	)	
PPL ELECTRIC UTILITIES CORPORATION	)	
	)	

SUPPLEMENTAL DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

DOCUMENT FOLDER

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JULY 9, 2007

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-00072155
PPL ELECTRIC UTILITIES CORPORATION	)	

SUPPLEMENTAL DIRECT TESTIMONY OF RICHARD A. GALLIGAN

I. Introduction

Q. PLEASE STATE YOUR NAME FOR THE RECORD.

A. My name is Richard A. Galligan. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044. I previously submitted direct testimony in this proceeding on July 6, 2007.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Under discovery procedures in this case, PPL preferred to run its class cost of service study as requested by the OCA, rather than make a working copy of its study available to participants. In making a study run for the OCA, an error relating to the allocation of secondary costs occurred. PPL has corrected its study run and transmitted the corrected study to the OCA on the afternoon of July 6, the direct testimony filing date. My supplemental direct testimony presents the results of the requested Peak and Average cost study and my recommended rate increase spread.

Q. PLEASE EXPLAIN SCHEDULE RAG-1.

A. Schedule RAG-1 presents the summary results from the Peak and Average class cost of service study where present rates are PPL Docket No. R-00049255 Remand Settlement rates. Pages 3 and 4 present class rates of return and class index rates of return on lines 28 and 29, respectively. Pages 5 and 6 of Schedule RAG-1 show class rates of return and class index rates of return at PPL proposed rates, including its proposed $83,521,000 rate increase. For example, these summary results show that regular Residential RS customers are paying present rates that yield a 5.93 percent rate of return, which is 96.58 percent of the overall system average rate of return of 6.14 percent at present rates. This result indicates that regular Residential RS customers should bear a portion of PPL's requested $83,521,000 rate increase. However, as shown on Schedule RAG-1 page 5, PPL overshot the mark by proposing an RS increase of $77,329,000 (shown on line 3). At this large proposed increase, RS customers would be paying rates that would yield a class rate of return of 9.64 percent, or 114.90 percent of the overall requested system average rate of return of 8.39 percent.

Q. PLEASE EXPLAIN SCHEDULE RAG-2.

A. Schedule RAG-2 simply displays in one place a summary of class results under PPL's customer/demand study and the Peak and Average study. Lines (1) - (4) show the class results under the two studies at present rates. Lines (5) - (8) show the class results at PPL's proposed rates. This is not an endorsement of PPL's proposed rates, but merely a device to allow presentation of a direct comparison between PPL's customer/demand study results and the Peak and Average study results.

Q. PLEASE EXPLAIN SCHEDULE RAG-3.

A. Schedule RAG -3 presents my proposed revenue spread. As explained in my direct testimony, I accept for purposes of this proceeding PPL's proposal to move each class one-half way toward allocated costs of service. I further limit any class from experiencing more than twice the 13 percent average Distribution rate increase proposed by PPL. Line (2) on Schedule RAG-3 shows the results of moving each class one-half way to costs of service. The one class affected by the percentage increase limit of twice the system average increase is the SL/AL class. Line (3) shows my recommended rate spread consistent with both the movement toward costs of service and consistent with the percentage limitation as well.

Q. WHAT DO YOU RECOMMEND FOR THE RESIDENTIAL THERMAL STORAGE CUSTOMERS SERVED ON RATE SCHEDULE RTS?

A. I recommend that these special, grandfathered customers experience no more than the $944 thousand dollar increase proposed by PPL. This can be accomplished by retaining within the combined Residential RS and RTS classes the difference between the $3,891,000 shown on Schedule RAG-3 line (3) and the $944,000. The result is shown on Schedule RAG-3 line (4).

Q. SHOULD THE COMMISSION AUTHORIZE A LESSER AMOUNT OF REVENUE THAN PPL HAS PROPOSED, WHAT DO YOU RECOMMEND?

A. I recommend that the revenue increases shown on Schedule RAG-3, line (4) be proportionately scaled back to the authorized revenue increase. For example, class scaled-back revenues consistent with a $34.6 million increase are shown on Schedule RAG-3 line (5).

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, at this time.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
	)	
v.	)	DOCKET NO. R-00072155
	)	
PPL ELECTRIC UTILITIES CORPORATION	)	

SCHEDULES ACCOMPANYING THE

SUPPLEMENTAL DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JULY 9, 2007

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

J. M. Kleha
(Updated 6/28/07)
(Revised 7/6/07)

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VIII,
Dated June 1,2007
Docket No. R-00072155

Q.1. Reference response to OCA Set IV, Q-1. Please provide another run incorporating the changes already included in the response, but please make the following changes:

- - Allocate Primary Substations plant and expenses 50% on class peak demands and 50% on class energy ("50/50");
- - Allocate Secondary Substations plant and expenses 50/50;
- - Allocate Primary Overhead Lines plant and expenses 50/50;
- - Allocate Primary Underground Lines and expenses 50/50;
- - Allocate Services plant and expenses 100% on a customer basis.

Please make sure the study run you prepare in responding to this request links the cost study spreadsheets so that those costs, whose allocations are affected by plant allocations, are allocated on the basis of the re-allocated plant costs.

A.1. Attachment 1 provides the requested re-run of Exhibit JMK 2, using a 50/50 demand/energy allocation and the parameters set forth in this interrogatory. It should be noted that, in order to accommodate the requested hypothetical within the existing structure and format of the Company's cost allocation model, certain primary and secondary plant and expense cost categories were combined for allocation as either demand or energy. However, the totals for each plant and expense cost category do agree with the totals shown in Exhibit JMK 2 as filed.

Note: Attachment 1 has been updated to include the effect on 2007 present revenues of the remand proceeding settlement.

Note: Per the request of the Office of Consumer Advocate, Attachment 1 was revised to separate the energy allocator between primary and secondary voltage levels.

PPL ELECTRIC UTILITIES CORPORATION

Exhibit JMK 2A
Cost Allocation Study
Test Year Ending December 31, 2007

Witness: Joseph M. Kleha
Docket No. R-00072155

REVISED TO INCLUDE EFFECT ON 2007 PRESENT REVENUES OF REMAND PROCEEDING SETTLEMENT

FURTHER REVISED FOR RESPONSE TO OCA SET VIII, Q.1.

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PRESENT OPERATING REVENUES AND EXPENSES, RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
PRESENT REVENUES INCLUDE EFFECT OF REMAND PROCEEDING SETTLEMENT
$1,000

Line No.		Output	Pa Jurisdict Distribution OCA Set VIII, Q.1	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
	OPERATING REVENUES AT PRESENT RATE LEVELS									
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0	0
2	REVISED DISTRIBUTION REVENUES		631,657	386,480	3,991	73,866	109,784	29,104	1,781	1,168
3	LATE PAY CHARGES PRESENT RATES	R11	8,923	5,825	46	1,182	1,137	417	21	165
4	SALE OF ELECTRICITY	RRT	640,580	392,305	4,037	75,048	110,921	29,521	1,802	1,333
5	ANNUALIZATION PRESENT REVENUES	ANN	1,724	2,355	(18)	(92)	386	(298)	74	(51)
6	ADJUSTED ELECTRIC SALES	0	642,304	394,660	4,019	74,956	111,307	29,223	1,876	1,282
7	OTHER OPERATING REVENUES	ROOT	32,379	18,080	604	2,617	7,635	1,334	70	46
8	TOTAL OPERATING REVENUES	ROT	674,683	412,740	4,623	77,573	118,942	30,557	1,946	1,328
	OPERATING EXPENSES									
	OPERATION AND MAINTENENCE EXPENSES									
9	TRANSMISSION	EE20	0	0	0	0	0	0	0	0
10	DISTRIBUTION	EE30	134,944	71,971	2,546	10,450	32,478	6,445	338	238
11	OTHER OPER & MAINT EXPENSES	EEOT	204,612	151,282	2,759	14,808	25,147	4,185	213	198
12	TOTAL OPER & MAINT EXPENSES	EE00	339,556	223,253	5,305	25,258	57,625	10,630	551	436
	DEPRECIATION EXPENSE									
13	TRANSMISSION	ED20	0	0	0	0	0	0	0	0
14	DISTRIBUTION	ED30	88,482	50,430	1,665	7,254	19,711	3,328	168	300
15	OTHER DEPREC EXP	EDOT	23,343	14,708	394	2,024	4,563	624	32	21
	TOTAL DEPRECIATION AND									
16	AMORTIZATION EXPENSE	ED00A	111,825	65,138	2,059	9,278	24,274	3,952	200	321
	TAXES									
17	CAPITAL STOCK PRESENT LEVEL	ET1	2,295	1,291	43	186	546	95	5	4
18	OTHER OTHER TAXES	ET001	9,654	5,897	169	820	1,935	335	18	11
19	DEFERRED INCOME TAXES	TXTA	8,378	4,879	144	645	1,867	324	15	12
20	NET INVESTMENT TAX CREDIT	TX93	(1,673)	(935)	(31)	(135)	(393)	(69)	(3)	(2)
21	GROSS RECEIPTS TAX	TXG	37,897	23,285	237	4,422	6,567	1,724	111	76
22	TOTAL PA INCOME TAX	TSIT1	9,705	5,015	(462)	3,149	1,045	1,077	90	31
23	TOTAL FED INC TAX	TFTX	32,788	17,398	(1,378)	10,007	3,566	3,420	283	100
24	TOTAL TAXES	TFIT1	99,044	56,830	(1,278)	19,094	15,133	6,906	519	232
25	TOTAL OPERATING EXPENSES	TEXP1	550,425	345,221	6,086	53,630	97,032	21,488	1,270	989
26	RETURN (LN 8 - 25)	PRERTN	124,258	67,519	(1,463)	23,943	21,910	9,069	676	339
27	TOTAL RATE BASE	RBX	2,022,968	1,138,053	38,595	161,125	483,424	85,020	4,457	3,072
28	RATE OF RETURN (LN 26 / LN 27)	PRRTR	6.14%	5.93%	-3.79%	14.86%	4.53%	10.67%	15.17%	11.04%
29	CLASS RATE IN % OF TOTAL	PRCLRT	100.00%	96.58%	-61.73%	242.02%	73.78%	173.78%	247.07%	179.80%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PRESENT OPERATING REVENUES AND EXPENSES, RETURN, RATE OF RETURN, AND CLASS RATE % OF TOTAL
PRESENT REVENUES INCLUDE EFFECT OF REMAND PROCEEDING SETTLEMENT
$1,000

Line No.		Output	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
	OPERATING REVENUES AT PRESENT RATE LEVELS	C							
	SALES OF ELECTRICITY								
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0
2	REVISED DISTRIBUTION REVENUES		564	36	333	538	6,459	17,518	35
3	LATE PAY CHARGES PRESENT RATES	R11	26	0	0	0	54	49	1
4	SALE OF ELECTRICITY	RRT	590	36	333	538	6,513	17,567	36
5	*ANNUALIZATION PRESENT REVENUES*	ANN	12	16	3	36	(61)	(625)	(13)
6	ADJUSTED ELECTRIC SALES	0	602	52	336	574	6,452	16,942	23
7	OTHER OPERATING REVENUES	ROOT	12	4	24	3	421	1,527	1
8	TOTAL OPERATING REVENUES	ROT	614	56	360	577	6,873	18,469	24
	OPERATING EXPENSES								
	OPERATION AND MAINTENENCE EXPENSES								
9	TRANSMISSION	EE20	0	0	0	0	0	0	0
10	DISTRIBUTION	EE30	64	23	14	14	1,802	8,558	8
11	OTHER OPER & MAINT EXPENSES	EEOT	36	13	77	8	1,478	4,411	3
12	TOTAL OPER & MAINT EXPENSES	EE00	100	36	91	22	3,280	12,969	11
	DEPRECIATION EXPENSE								
13	TRANSMISSION	ED20	0	0	0	0	0	0	0
14	DISTRIBUTION	ED30	80	29	86	19	1,185	4,216	9
15	OTHER DEPREC EXP	EDOT	5	1	11	1	251	710	0
	TOTAL DEPRECIATION AND								
16	*AMORTIZATION EXPENSE*	ED00A	85	30	97	20	1,436	4,926	9
	TAXES								
17	*CAPITAL STOCK PRESENT LEVEL*	ET1	1	0	1	0	30	93	0
18	OTHER OTHER TAXES	ET001	4	2	5	0	108	350	0
19	DEFERRED INCOME TAXES	TXTA	4	1	7	0	102	371	1
20	NET INVESTMENT TAX CREDIT	TX93	(1)	0	(1)	0	(22)	(81)	0
21	GROSS RECEIPTS TAX	TXG	36	3	20	34	381	1,000	1
22	TOTAL PA INCOME TAX	TSIT1	34	(3)	11	49	81	(396)	0
23	TOTAL FED INC TAX	TFTX	107	(9)	34	152	220	(1,115)	(1)
24	*TOTAL TAXES*	TFIT1	185	(6)	77	235	880	222	1
25	TOTAL OPERATING EXPENSES	TEXP1	370	60	265	277	5,596	18,117	21
26	RETURN (LN 8 - 25)	PRERTN	244	(4)	95	300	1,277	352	3
27	TOTAL RATE BASE	RBX	818	291	820	190	26,731	80,262	91
28	RATE OF RETURN (LN 26 / LN 27)	PRRTR	29.83%	-1.37%	11.59%	157.89%	4.78%	0.44%	3.30%
29	CLASS RATE IN % OF TOTAL	PRCLRT	485.83%	-22.31%	188.78%	2571.50%	77.85%	7.17%	53.75%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PROPOSED REVENUES AND EXPENSES, RETURN, RATE OF RETURN AND CLASS RATE % OF TOTAL
REVENUES INCLUDE EFFECT OF REMAND PROCEEDING SETTLEMENT
$1,000

Line No.		Output	Pa Jurisdict Distribution	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
	OPERATING REVENUES AT PROPOSED RATE LEVELS		OCA Set VIII, Q.1							
	SALES OF ELECTRICITY									
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		631,657	386,480	3,991	73,866	109,784	29,104	1,781	1,168
3	PROPOSED REVENUE INCREASE		83,521	77,329	944	845	612	(391)	(107)	(135)
	ADJUSTED RATE REVENUES		715,178	463,809	4,935	74,711	110,396	28,713	1,674	1,033
4	LATE PAYMENT CHARGES	R11P	8,923	5,825	48	1,182	1,137	417	21	165
5	ANNUALIZATION ADJUSTMENT	ANNP	1,726	2,357	(18)	(92)	386	(298)	74	(51)
6	TOTAL SALE OF ELECTRICITY	RRTP	725,827	471,991	4,963	75,801	111,919	28,832	1,769	1,147
7	PROPOSED SALES & LATE PAYMENTS	ARTTP	725,827	471,991	4,963	75,801	111,919	28,832	1,769	1,147
8	OTHER OPERATING REVENUES	ROOT	32,379	18,080	604	2,617	7,635	1,334	70	46
9	TOTAL OPERATING REVENUES	ROTP	758,206	490,071	5,567	78,418	119,554	30,166	1,839	1,193
	OPERATING EXPENSES									
	OPERATION AND MAINTENANCE EXPENSES									
10	TRANSMISSION	EE20	0	0	0	0	0	0	0	0
11	DISTRIBUTION	EE30	134,944	71,971	2,546	10,450	32,478	6,445	338	236
12	OTHER OPER & MAINT EXPENSES	EEOT	205,281	151,901	2,761	14,836	25,163	4,186	213	199
13	TOTAL OPER & MAINT EXPENSES	EE00	340,225	223,872	5,307	25,286	57,641	10,631	551	437
	DEPRECIATION EXPENSE									
14	TRANSMISSION	ED20	0	0	0	0	0	0	0	0
15	DISTRIBUTION	ED30	88,482	50,430	1,665	7,254	19,711	3,328	168	300
16	OTHER DEPRECIATION EXPENSE	EDOT	23,343	14,708	394	2,024	4,563	624	32	21
17	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE	ED00	111,825	65,138	2,059	9,278	24,274	3,952	200	321
	TAXES									
18	CAPITAL STOCK PROP LEVEL	ET1P	2,517	1,416	47	203	599	104	5	4
19	OTHER-W/O CAP STOCK	ET001	9,654	5,894	169	820	1,935	335	18	11
20	DEFERRED INCOME TAXES	TXTA	8,378	4,879	144	645	1,867	324	15	12
21	NET INVESTMENT TAX CREDIT	TX93	(1,673)	(935)	(31)	(135)	(393)	(69)	(3)	(2)
22	GROSS RECEIPTS TAX	TXG	42,824	27,847	293	4,472	8,603	1,701	104	68
23	TOTAL PA INCOME TAX	TSIT1	17,468	12,208	(374)	3,224	1,096	1,039	80	19
24	TOTAL FED INC TAX	TFTX	57,267	40,088	(1,101)	10,243	3,726	3,301	252	59
25	TOTAL TAXES	TFIT1	136,435	91,393	(853)	19,472	15,433	6,735	471	171
26	TOTAL OPERATING EXPENSES	TEXP1	588,485	380,403	6,513	54,036	97,348	21,318	1,222	929
27	RETURN (LN 9 - 26)	PRERTN	169,721	109,668	(946)	24,382	22,206	8,848	617	264
28	TOTAL RATE BASE	RBX	2,022,968	1,138,049	38,595	161,125	483,424	85,020	4,457	3,072
29	RATE OF RETURN (LN 27 / LN 28)	PRRTR	8.39%	9.64%	-2.45%	15.13%	4.59%	10.41%	13.84%	8.59%
30	CLASS RATE IN % OF TOTAL	PRCLRT	100.00%	114.90%	-29.20%	180.33%	54.71%	124.08%	164.96%	102.38%

PPL ELECTRIC UTILITIES CORPORATION
COST ALLOCATION DETAILS - 12 MONTHS ENDED 12/31/2007
PROPOSED REVENUES AND EXPENSES, RETURN, RATE OF RETURN AND CLASS RATE % OF TOTAL
REVENUES INCLUDE EFFECT OF REMAND PROCEEDING SETTLEMENT
$1,000

Line No.		Output	IST	LP-6	LPEP	ISA	GH	SL/AL	LS-S
	OPERATING REVENUES AT PROPOSED RATE LEVELS								
	SALES OF ELECTRICITY								
1	TRANSMISSION REVENUES		0	0	0	0	0	0	0
2	DISTRIBUTION REVENUES		564	36	333	538	6,459	17,518	35
3	PROPOSED REVENUE INCREASE		(127)	(5)	(1)	6	542	4,007	2
	ADJUSTED RATE REVENUES		437	31	332	544	7,001	21,525	37
4	LATE PAYMENT CHARGES	R11P	26	0	0	0	54	49	1
5	ANNUALIZATION ADJUSTMENT	ANNP	12	16	3	36	(61)	(625)	(13)
6	TOTAL SALE OF ELECTRICITY	RRTP	475	47	335	580	6,994	20,949	25
7	PROPOSED SALES & LATE PAYMENTS	ARTTP	475	47	335	580	6,994	20,949	25
8	OTHER OPERATING REVENUES	ROOT	12	4	24	3	421	1,527	1
9	TOTAL OPERATING REVENUES	ROTP	487	51	359	583	7,415	22,476	26
	OPERATING EXPENSES								
	OPERATION AND MAINTENANCE EXPENSES								
10	TRANSMISSION	EE20	0	0	0	0	0	0	0
11	DISTRIBUTION	EE30	64	23	14	14	1,802	8,558	8
12	OTHER OPER & MAINT EXPENSES	EEOT	36	13	77	8	1,479	4,411	3
13	TOTAL OPER & MAINT EXPENSES	EE00	100	36	91	22	3,281	12,969	11
	DEPRECIATION EXPENSE								
14	TRANSMISSION	ED20	0	0	0	0	0	0	0
15	DISTRIBUTION	ED30	80	29	86	19	1,185	4,216	9
16	OTHER DEPRECIATION EXPENSE	EDOT	5	1	11	1	251	710	0
	TOTAL DEPRECIATION AND								
17	AMORTIZATION EXPENSE	ED00	85	30	97	20	1,436	4,926	9
	TAXES								
18	CAPITAL STOCK PROP LEVEL	ET1P	1	0	1	0	32	102	0
19	OTHER-W/O CAP STOCK	ET001	4	2	5	0	108	350	0
20	DEFERRED INCOME TAXES	TXTA	4	1	7	0	102	371	1
21	NET INVESTMENT TAX CREDIT	TX93	(1)	0	(1)	0	(22)	(81)	0
22	GROSS RECEIPTS TAX	TXG	28	3	20	34	413	1,236	1
23	TOTAL PA INCOME TAX	TSIT1	22	(3)	11	50	112	(21)	0
24	TOTAL FED INC TAX	TFTX	69	(11)	34	154	379	71	0
25	TOTAL TAXES	TFIT1	127	(8)	77	238	1,124	2,028	2
26	TOTAL OPERATING EXPENSES	TEXP1	312	58	265	280	5,841	19,923	22
27	RETURN (LN 9 - 26)	PRERTN	175	(7)	94	303	1,574	2,553	4
28	TOTAL RATE BASE	RBX	818	291	820	190	26,731	80,262	91
29	RATE OF RETURN (LN 27 / LN 28)	PRRTR	21.39%	-2.41%	11.46%	159.47%	5.89%	3.18%	4.40%
30	CLASS RATE IN % OF TOTAL	PRCLRT	254.95%	-28.72%	136.59%	1900.72%	70.20%	37.90%	52.44%

PPL Electric Utilities Corporation
Class Rates of Return Under Cost Study Alternatives
Test Year 2007
(%)

	DISTRIBUTION	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
OPERATING REVENUES AT PRESENT RATE LEVELS								
(1) Rate of Return (Peak & Average)	6.14	5.93	-3.79	14.86	4.58	10.67	15.17	11.04
(2) Index Return	100.00	96.58	-61.73	242.02	73.78	173.78	247.07	179.80
(3) Rate of Return (Customer/Peak)	6.14	4.08	-3.89	12.60	12.00	12.79	18.59	10.87
(4) Index Return	100.00	66.45	-63.36	205.21	195.44	206.31	302.77	177.04
OPERATING REVENUES AT PPL PROPOSED RATES								
(5) Rate of Return (Peak & Average)	8.39	9.64	-2.45	15.13	4.59	10.41	13.84	8.59
(6) Index Return	100.00	114.90	-29.20	180.33	54.71	124.08	164.96	102.38
(7) Rate of Return (Customer/Peak)	8.39	7.26	-2.56	12.84	12.10	12.50	17.05	8.43
(8) Index Return	100.00	86.53	-30.51	153.04	144.22	148.99	203.22	100.48

PPL Electric Utilities Corporation
Class Rates of Return Under Cost Study Alternatives
Test Year 2007
(%)

	IST	LP-6	LPEP	ISA	GH	SL/AL	LS-S
OPERATING REVENUES AT PRESENT RATE LEVELS							
(1) Rate of Return (Peak & Average)	29.83	-1.37	11.59	157.89	4.78	0.44	3.30
(2) Index Return	485.83	-22.31	188.76	2,571.50	77.85	7.17	53.75
(3) Rate of Return (Customer/Peak)	29.76	-1.70	14.01	157.89	7.57	0.56	1.06
(4) Index Return	484.69	-27.69	228.18	2,571.50	123.29	9.12	17.26
OPERATING REVENUES AT PPL PROPOSED RATES							
(5) Rate of Return (Peak & Average)	21.39	-2.41	11.46	159.47	5.89	3.18	4.40
(6) Index Return	254.95	-28.72	136.59	1,900.72	70.20	37.90	52.44
(7) Rate of Return (Customer/Peak)	21.34	-2.38	13.89	159.47	8.94	3.38	2.13
(8) Index Return	254.35	-28.37	165.55	1,900.72	106.56	40.29	25.39

PPL Electric Utilities Corporation
Distribution Revenue Increase Spread
($000s)

		DISTRIBUTION	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5
(1)	PPL Proposed Revenue Spread	83,521	77,329	944	845	612	(391)	(107)	(135)
(2)	OCA Calculated Revenue Spread[1]	83,541	48,372	3,826	(1,516)	24,492	1,278	(50)	40
(3)	Adjusted Revenue Spread[2]	83,541	49,195	3,891	(1,516)	24,908	1,300	(50)	40
(4)	OCA Proposed Revenue Spread	83,521	52,142	944	(1,516)	24,908	1,300	(50)	40
(5)	Scale-Back Revenue Spread	34,600	22,241	403	(1,516)	10,625	554	(50)	17

[1] Adopts PPL Proposed total Distribution increase for illustrative purposes only. This calculated revenue spread shows the change in class revenues necessary to close one-half of the indicated differences between class rates of return and system average rate of return.

[2] This adjusted revenue spread shows the effect on class revenues of limiting the SL/AL increase to twice the system average increase. The SL/AL class is the only class whose rate increase is limited by the rule that no class should pay an increase that exceeds twice the system average increase.

	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
(1) PPL Proposed Revenue Spread	(127)	(5)	(1)	(6)	(542)	4,007	2
(2) *OCA Calculated Revenue Spread*[1]	(79)	25	8	(160)	1,318	5,982	5
(3) Adjusted Revenue Spread[2]	(79)	25	8	(160)	1,340	4,633	5
(4) OCA Proposed Revenue Spread	(79)	25	8	(160)	1,340	4,633	5
(5) Scale-Back Revenue Spread	(79)	11	3	(160)	572	1,976	2

[1] Adopts PPL Proposed total Distribution increase for illustrative purposes only. This calculated revenue spread shows the change in class revenues necessary to close one-half of the indicated differences between class rates of return and system average rate of return.

[2] This adjusted revenue spread shows the effect on class revenues of limiting the SL/AL increase to twice the system average increase. The SL/AL class is the only class whose rate increase is limited by the rule that no class should pay an increase that exceeds twice the system average increase.

OCA Statement No. 1R

Hdg TX AUG 16 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCUMENT FOLDER

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
	)	
v.	)	DOCKET NO. R-00072155
	)	
PPL ELECTRIC UTILITIES CORPORATION	)	

DOCKETED SEP 7 - 2007

REBUTTAL TESTIMONY

OF

RICHARD A. GALLIGAN

RECEIVED AUG 17 2007 PA PUBLIC UTILITY COMMISSION SECRETARY'S BUREAU

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JULY 27, 2007

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-00072155
PPL ELECTRIC UTILITIES CORPORATION	)	

REBUTTAL TESTIMONY OF RICHARD A. GALLIGAN

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Galligan. I am a Principal with Exeter Associates, Inc., a firm of consulting economists specializing in utility economics. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044. I filed Direct and Supplemental Direct Testimony, OCA Statement Nos. 3 and 1-Supplemental, on July 6 and 10, respectively.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. Messrs. Knecht, Baron and Kincel comment in their direct testimonies about the choice of average cost studies to be used in the determination of how PPL should spread any increased revenues resulting in this proceeding. Mr. Kincel further opines that rates must be set at average embedded costs or the rates will be improper price signals and will be economically inefficient. My rebuttal testimony addresses these issues.

Q. PLEASE DESCRIBE THE AVERAGE, EMBEDDED ALLOCATED COST OF SERVICE STUDIES PROPOSED BY THE PARTIES IN THIS PROCEEDING.

A. There are two average, embedded allocated cost studies proposed by the parties in this proceeding.

One, PPL's proposed customer/demand study. This study is based on the assumption that roughly 60 percent of PPL's lines, poles and transformer distribution plant and related costs are incurred to provide a customer "connection" service and allocates these costs on a customer basis. The remaining 40 percent of these costs is then allocated on each class's peak demands. PPL's proposed study allocates 100 percent of primary distribution costs on the basis of class peak demands. Messrs. Knecht, Baron and Kincel endorse the utilization of PPL's customer/demand cost study results as the basis for determining how PPL's need for additional revenues should be spread among the classes.

Two, the Peak and Average study. This study allocates PPL's primary and secondary distribution plant upstream of meters and services 50 percent on the basis of class average demands and 50 percent on the basis of class peak demands. These are the two-class cost of service studies available in this proceeding for use as a guide to determine a reasonable allocation among the classes of any Commission-authorized increase in revenues.

Q. IS THERE A COMMON BASIS AMONG MESSRS. KNECHT, BARON AND KINCEL FOR PREFERRING PPL'S PROPOSED CUSTOMER/DEMAND STUDY?

A. Yes. Messrs. Knecht, Baron and Kincel agree with PPL's allocation of a substantial portion of distribution costs upstream of meters and services on a customer basis with the allocation of the remaining non-customer portion of costs on class peak demands. Neither PPL nor Messrs. Knecht, Baron, and Kincel advocate the allocation of any distribution costs on the base of average demands, or annual energy.

Q. MESSRS. KNECHT AND BARON ARGUE THAT DISTRIBUTION PLANT MUST BE BUILT TO CONNECT CUSTOMERS AND TO PROVIDE POWER DURING PEAK PERIODS, AND THEREFORE DISTRIBUTION PLANT COSTS ARE TOTALLY CAUSED BY BOTH THE NUMBER OF CUSTOMERS AND CUSTOMER PEAK DEMANDS. PLEASE COMMENT.

A. At page 6, line 21 through page 7, line 1, Mr. Knecht states:

> Distribution plant must be built to accomplish the dual objectives of (a) interconnecting all of the customers on the system and (b) providing power to customers during periods of peak demand. Therefore, distribution plant costs are causally related to both the number of customers and customer peak demands.

Mr. Baron, discussing the basing of customer cost determination on the minimum system concept at page 12 of his testimony puts it this way:

> This approach reasonably recognizes the "cost causation" underlying distribution plant investment and should be used to allocate costs.

Messrs. Knecht and Baron reason that since conductors and other related facilities are required to flow electricity to PPL's customers, a substantial portion of PPL's distribution facilities constructed upstream of services and meters is caused by the existence of a customer. This reasoning is incorrect.

On the very first page of the chapter introducing the concept of cost studies, "Overview of Cost of Service Studies and Cost Allocation," the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") explains that an important purpose of cost studies is "To calculate costs of individual types of service based on the costs each service requires the utility to expend." [NARUC Manual, p. 12, emphasis added] Here, the NARUC Manual is not addressing any particular method of cost allocation, but simply explaining that costs are properly allocated to the service units based on the costs of each service. Clearly, costs are incurred to the provide real service attributes, i.e., the delivery of electrical energy whenever and in whatever amounts electricity is demanded, not to "connect" customers. Costs are caused by the provision of service, and it is the provision of service that causes costs.

The primary service that PPL provides is the delivery of electric energy anytime during the year whenever, and in the amounts, its customers demand electricity. PPL also provides reliability (at all times throughout the year), accurate and efficient billing and record keeping, etc.

- PPL is not in the business of providing "connection" service;
- PPL does not offer connection service;
- PPL's tariff does not include connection service absent coincidental, non-speculative, sustained requirements for electricity;
- PPL's tariff contains terms and conditions that protect PPL and its customers from incurring costs associated with a customer who would demand "connection" service but has no requirements for electricity;
- There is no demand for "connection" service; and
- PPL would not be a viable business entity, being able to raise capital in order to provide service and recover its capital costs, if it simply faced a market for connection service by customers who had no sustained demands for electricity.

In contrast to the customer/demand study method, which allocates costs to a non-existent customer connection service, the Peak and Average cost study method allocates costs to average, i.e., annual, demands -- a real service that not only causes costs, but is the basic, primary service that is responsible for PPL incurring electricity delivery costs in the first place. And because demands are not constant but vary over time, and because additional costs are caused by providing delivery service commensurate with peak demands, the Peak and Average method also allocates a significant portion of costs to those peak demands.

Q. DO YOU AGREE WITH THE OTHER WITNESSES' RELIANCE ON THE NARUC MANUAL FOR THEIR VIEWS AS TO WHICH PARTICULAR METHOD SHOULD BE UTILIZED TO CLASSIFY AND ALLOCATE DISTRIBUTION PLANT AND RELATED COSTS?

A. No. At page 7, lines 16-19, Mr. Knecht testifies:

> The standard application of either the minimum system or the zero-intercept methodology requires that both primary voltage and secondary voltage distribution costs be split into demand and customer components.[8]
>
> [8]"Electricity Utility Cost Allocation Manual, "National Association of Regulatory Utility Commissioners, January 1992, page 93.

The NARUC Manual does not "require" that primary costs be classified, in part, on a customer basis.

First, the NARUC Manual explains how various cost practitioners allocate costs when performing a cost study. The NARUC Manual is positive, not normative. It is a simple, declarative document; it does not advocate a particular method. In discussing the manual's objectives, it states:

> "The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons." [NARUC Manual, p. ii]

At the end of the introductory chapter, "Overview of Cost of Service Studies and Cost Allocation," the NARUC Manual states:

> This manual only discusses the major costing methodologies. It recognizes that no single costing methodology will be superior to any other and the choice of methodology will depend on the unique circumstances of each utility. Individual costing methodologies are complex and have inspired numerous debates on application, assumptions and data. Further the role of cost in ratemakings is itself not without controversy.....
>
> The purpose of this manual is to clarify, if not resolve, some of that confusion." [Ibid., pp. 22-23]

References to the NARUC Manual for authoritative support "requiring" any particular cost allocation method are misplaced.

Second, while Messrs. Knecht, Baron and Kincel totally omit the allocation of any portion of PPL's distribution costs on an energy basis, that allocation method is clearly included in the allocation methodologies described in the NARUC Manual. For example, the classifications listed on page 21 of the NARUC Manual clearly include and provide for an energy allocation of distribution costs. Again, at page 34 of the NARUC Manual, the table shown there provides for an energy allocation of distribution facilities upstream of meters and services. The NARUC Manual includes the customer classification of costs that Messrs. Knecht, Baron and Kincel prefer, as well as the energy classification that I advocate, in its discussion of major costing methodologies. The NARUC Manual explains, as discussed above, that its purpose is to provide an exposition of all currently used methods, not advocating any one particular method.

Q. IS THERE OTHER EVIDENCE THAT THE FARTHER UPSTREAM OF SERVICES AND METERS, THE LESS APPLICABLE IS THE NOTION OF SO-CALLED CUSTOMER COSTS, AND THE MORE CONTROVERSIAL ARE THE RESULTS?

A. Yes. Professor Bonbright, in discussing the controversial nature of minimum-sized distribution costs as customer costs limits the application of this concept to secondary distribution costs:

> The really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) *distribution system -- a fraction equal to the estimated annual costs of* a hypothetical system of minimum capacity." [Bonbright, James C., Principles of Public Utility Rates, Public Utility Reports, Arlington, VA, 1988, p. 491, emphasis added]

Extending the controversial notion of customer costs upstream of services and meters into the higher primary voltage facilities is not even considered by Professor Bonbright. While the entire notion of a customer cost component of distribution costs upstream of services and meters is fraught with controversy, the farther upstream the facilities, the greater the controversy. Discussing the concept of customer cost classification in the performance of a gas distribution cost study Gas Rate Fundamentals puts it this way:

> The closer a plant item (e.g., a meter and service line) is located to a customer, the more that particular item is related to the specific requirements of that customer." [American Gas Association Rate Committee, Gas Rate Fundamentals, American Gas Association, Arlington, VA, 1987]

Primary electric facilities are upstream of secondary facilities and are higher voltage facilities. Whereas meters and service are related to a specific customer, secondary distribution facilities are related to coincident customer load requirements. Primary facilities are even more remote to customers. Primary facilities deliver electricity to secondary facilities. Primary facilities exist to provide for the delivery of electrical energy requirements whenever and in whatever amounts are required. The concept of customer costs, however controversial at the secondary voltages level, is even less applicable at primary voltage levels. PPL's decision to not classify and allocate primary costs on the basis of non-existent customer "connection" costs does not correct the shortcomings or eliminate the controversy of classifying and allocating a substantial fraction of its secondary distribution costs to a non-existent service.

Q. MR. BARON, AT PAGE 10 OF HIS DIRECT TESTIMONY STATES THAT PPL'S COST STUDY IS CONSISTENT WITH METHODS DISCUSSED IN THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL. PLEASE COMMENT.

A. PPL's customer/demand cost study methodology is consistent with one method discussed in the NARUC Manual. As explained above, the NARUC Manual "discusses the major costing methodologies" but "recognizes that no one methodology will be superior to the others, and "does not advocat[e] any one particular method." A simple declarative exposition of the theory and methodology of any particular cost study variant included in the NARUC Manual does not alleviate attendant controversy, nor is it dispositive of the issue of which cost study methodology is superior to all others.

Q. MR. KINCEL STATES AT PAGE 7 OF HIS DIRECT TESTIMONY THAT, "THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL (JANUARY 1992, P. 12) CLEARLY STATES THIS 'COST PRINCIPLE,' THAT IS, THAT THE COST ALLOCATION STUDY SHOULD

'ATTRIBUTE COSTS TO DIFFERENT CATEGORIES OF CUSTOMERS BASED ON HOW THOSE CUSTOMERS CAUSE COSTS TO BE INCURRED.'" PLEASE COMMENT.

A. In this portion of Mr. Kincel's testimony, he is arguing that no portion of distribution costs should be allocated on energy. Mr. Kincel further argues that the sole determination of the need for additional distribution capacity is greater peak load requirements, and therefore, only peak demands should be used to allocate all non-customer classified costs.

Mr. Kincel creates two time periods -- a period coinciding with class peak demands, and a period of time characterized by all lesser demands. Mr. Kincel reasons that all distribution costs are caused by a coincidence of energy demands that would sum to the greatest total demand at some particular time during the year. Only that maximum load is deemed by Mr. Kincel to have caused all the distribution costs that he does not otherwise call customer costs.

Mr. Kincel's analysis is incomplete, at best. Under Mr. Kincel's theory, no costs would be allocated to the overwhelmingly primary service that PPL provides-- the delivery of energy whenever throughout the year delivery service is required. Yes, peak demands are more costly to serve than annual, or average, demands. This is recognized by the allocation of fully 50 percent of distribution costs on a peak demand basis under the Peak and Average methodology. Mr. Kincel fails to investigate and analyze the costs incurred to provide delivery service to meet average demands and the extra or incremental costs that relate to delivering peak demands. Mr. Kincel simply dismisses the impact of all other loads during the year by reasoning that if you construct delivery capacity to meet the peak, you automatically have enough capacity to meet all other demands. Mr. Kincel's casual dismissal of all lesser demands mistakenly ignores the fact that PPL would not incur any costs (i.e., it would not exist) if customers had a demand for electricity during only one of the 8,760 hours in a year. Thus, substantial costs are related to the annual, or average, demands for electricity that cause those costs to exist, and additional costs, not all costs, are related to the provision of service at the time of peak demand. Moreover, PPL's service extension rules are not consistent with Mr. Kincel's allocation proposal, because PPL is prohibited from extending service to a customer who would use electricity only one hour per year. PPL's customers do not have appliance stocks that use electricity only at the time of class peak demands, and thus, demand and demand growth do not occur uniquely at only the time of class peaks.

Q. AT PAGE 11 OF HIS DIRECT TESTIMONY, MR. KINCEL TESTIFIES, "OPTIMAL EFFICIENCY OCCURS WHEN EACH CUSTOMER CLASS IS PAYING THE AVERAGE SYSTEM RETURN TO THE COMPANY IN ITS RATES." PLEASE COMMENT.

A. Mr. Kincel is incorrect. Optimal efficiency occurs when price equals marginal cost, not average cost. This most basic of economic precepts is explained in all economic principles textbooks. PPL's marginal delivery cost is less than its average cost, therefore, setting prices equal to average cost would ensure that price will not equal marginal cost. No claims regarding optimal efficiency attend a prescription of setting price equal to average cost.

Q. MESSRS. KNECHT, BARON AND KINCEL SUPPORT MOVEMENT TOWARD COST OF SERVICE IN THIS CASE, BUT EACH OF THEM PROPOSES A VARIANT TO PPL'S PROPOSED SPREAD OF ITS REQUESTED INCREASE. PLEASE COMMENT.

A. In PPL's remand proceeding, Docket No. R-00049255, PPL moved classes toward cost of service, proposed to move class one-half way toward allocated costs in this case, and move classes to cost of service in its next case. The one-half movement toward cost of service in this case and the proposed full movement to costs in PPL's next case are measured in terms of closing the gap between class index rates of return and PPL's system average rate of return. Under these circumstances, I see no impelling rationale to stray from the Commission's traditional reliance on class index rates of return and adopt other alternative proposals in this proceeding.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes.

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OCA Statement No. 3

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	DOCKET NO. R-00072155
PPL ELECTRIC UTILITIES CORPORATION	)	

DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

DOCKETED SEP 7 - 2007

TOPIC ADDRESSED:
RATE STRUCTURE

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JULY 6, 2007

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

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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DIRECT TESTIMONY OF RICHARD A. GALLIGAN

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

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

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

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

In January 1975, I joined the staff of the Minnesota Public Service Commission at the commencement of that Commission's responsibility over gas and electric utility operations in the State of Minnesota. From 1976 to 1984, I was an economic consultant specializing in public utility rate regulation of gas, electric and telephone utilities.

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

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

A. Yes. I have previously presented testimony on more than 100 occasions before the Federal Energy Regulatory Commission ("FERC") and the public utility commissions of Alabama, California, Connecticut, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Kansas, Louisiana, Maryland, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, and Vermont.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Exeter Associates, Inc. was retained by the Pennsylvania Office of Consumer Advocate ("OCA") to review the class cost of service studies, proposed revenue allocation and rate design proposals for the residential class reflected in PPL Electric Utilities Corporation's ("PPL's" or "the Company's") current application for a general rate increase. My testimony addresses the allocation of certain distribution costs in the cost of service study, the revenue allocation, and rate design issues applicable to the Residential class.

Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?

A. Yes. Schedules RAG-1 through RAG-3 will be prepared by me after receipt from the Company of a corrected cost of service study recently requested. As discussed in more detail below, PPL is re-running a cost study I requested which inadvertently contained an error. Schedule-4 is attached to my testimony.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

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

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

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

A. I have reached the following conclusions:

- PPL's allocation of a large portion of its secondary distribution plant and related costs is at odds with the principle of cost causality, and produces unrealistic indications of calculated class rates of return;
- The fundamental service that PPL provides is the delivery of its customers' annual energy requirements at all times during the year, and at varying rates of delivery;
- A large portion of PPL's annual delivery costs are directly related to the fundamental service that PPL provides;
- PPL's proposed cost-of-service study allocates no distribution costs on the basis of the fundamental service it provides, violating the principle that costs should be allocated on the basis of the service units that cause the costs to be incurred;
- The allocation of Common Distribution plant investment, partially on the basis of average demands and partially on the basis of peak demands eliminates the misallocations in PPL's studies by reflecting the load carrying capabilities of the distribution system, and is consistent with the principle of cost causality;
- PPL's proposed revenue spread, tied to its cost study which misallocates major Distribution costs of service, is unreasonable;
- The requested authority to increase the Residential RS Distribution Charge from $7.96 to $10.00 should be denied; and
- PPL's proposal to front-load its residential revenue increase by increasing its first-block rate by 39 percent, its second-block rate by 27 percent, and actually decreasing its third-block, or tailblock, rate by 6 percent should be rejected.

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

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

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

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

A. PPL's Distribution plant can be typified in a number of ways. One useful way to understand the allocation issues regarding PPL's distribution plant is to divide distribution plant into three categories: (1) "Primary Distribution" plant, which includes PPL's distribution substations and primary overhead and underground lines; (2) "Common Distribution" plant, which consists of the lower, secondary portion of PPL's distribution plant, including secondary overhead and underground lines, poles, and line transformers; and (3) "Services and Meters" plant. Common Distribution Plant is system plant, since it generally serves more than one customer and is built and must be sized to provide for various demands that may be placed on the plant components. Services and Meters plant consists of exactly those two components and is that portion of PPL's plant which is located closest to its customers, providing the delivery of electricity to individual customers.

The Primary Distribution plant delivers electricity from the Transmission system to the secondary system, stepping the voltages down from 69 kV, 23 kV and 12 kV and ultimately to secondary voltage levels. The Common Distribution plant distributes electricity throughout PPL's service area by delivering electricity from the primary system to customer Services while completing the transformation of voltages down to delivery level voltages. Generally, Services complete the delivery of electricity from the output side of line transformers to the Meter located on or near structures on the customers' premises. As mentioned above, Common Distribution plant, including overhead and underground lines, poles and line transformers performs a system function, being plant that is generally used by multiple customers. Primary Distribution plant, too, including substations and primary lines, performs a system function and is generally used by multiple customers. Just as with Common Distribution Plant, Primary Distribution plant exists not only to provide for the delivery of electricity whenever customers require electricity, but must be sized to also provide for the maximum coincident loads that the plant may be required to serve. Because Services and Meters plant is generally associated with the provision of service to individual customers, it does not perform a system function.

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

A. Each of the three categories of distribution plant were allocated by PPL on one of three different allocation bases. Generally, Services plant was allocated predominantly on the basis of the number of customers and partially on the basis of class peak demands. Meters plant was allocated by PPL to classes on a customer count basis. Common Distribution plant, including lines, poles and line transformers, was allocated on both a customer and a class peak demand basis. The customer/demand allocation of Common Distribution plant resulted in an overall 58.5 percent customer component and a 41.5 percent demand component when applied to lines, poles and line transformers. The Primary Distribution plant was allocated to classes solely on the basis of class noncoincident demands, regardless of when during the year the class peak is established.

PPL's allocations of its Primary Distribution plant, its system integrated Common Distribution plant, and its Services plant contain misallocations of costs and produce unreliable indications of the cost of providing service to its several customer classes. Immediately below I discuss the misallocations inherent in PPL's allocation of its Distribution plant.

<u>The Misallocation of Common Distribution Plant Inherent in PPL's Cost Studies</u>

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

A. The so-called customer component of Common Distribution facilities is the amount of plant required to connect the customers, but also is an amount so meager in design that it can, in fact, deliver no electricity. The Company determined its customer component of Common Distribution plant based on the minimum system cost concept. Under this approach, the customer component of each plant account that is deemed to be partially customer and partially demand related was determined by PPL based on the smallest sized plant that is capable of providing service to the customers' load. PPL determined the customer related portion of its poles, lines and line transformers by first determining how much of its investment installed in each of these type of plants would have cost, if the total amount of each type of plant were based entirely on the costs of its minimum sized equipment. PPL used the minimum sized equipment it currently installs as the basis for determining the minimum cost it would incur to deliver electricity to its customer loads if all of its customers were provided service with the minimum sized system. Since the minimum sized system can, in fact, flow electricity and meet a portion of customer load requirements, PPL adjusted its minimum sized system to remove the estimated capacity costs included in the minimum sized system.

For example, the minimum sized pole PPL currently installs is a 40-foot pole. The total calculated cost of all of PPL's 893,138 actual poles of varying size would be $440,685,089 if each actual installed pole were to cost the same as PPL's average embedded $493.41 cost of its 388,753 40-foot poles. This $440,685,089 plant investment cost that PPL would have incurred, if all its poles were installed at the cost of its minimum sized poles, compares to PPL's actual book cost of $718,486,800 for the actual poles PPL did install. The ratio of the calculated pole investment costs if all the poles were of the minimum size, to the pole investment cost of PPL's actual poles installed, in this case 61.30 percent, is deemed to be the customer portion. The cost in excess of the 61.30 percent customer portion, or 38.70% (100% - 61.30% = 38.70%), is deemed to be demand related.

Details of PPL's determination of each of the customer components that PPL contends is included in its Common Distribution plant are shown in PPL witness Kleha's Exhibit JMK-3 at page 13. For each account deemed by PPL to have a customer component, the customer component is based on the ratio of the investment cost PPL would have incurred, if all pieces of equipment in the account were of the minimum sized component that PPL currently installs, compared to the investment cost of PPL's actual equipment installed, adjusted downward to eliminate the estimated demands that could be met with the minimum sized system.

Q. PLEASE EXPLAIN THE CONCEPT OF A SO-CALLED CUSTOMER COST COMPONENT OF PPL'S COMMON DISTRIBUTION SYSTEM.

A. The so-called customer component of PPL's Common Distribution facilities (poles, transformers, conductors) relates to determining the costs of system facilities that are so skimpy that they would be able to "connect" the customers but not be able to actually flow any electricity to the customers. Customer costs are supposed to vary with the number of customers. Professor Bonbright refers to the estimated costs of the hypothetical minimum sized system as a "phantom" system. [Bonbright, James C., et al.

Principles of Public Utility Rates, Public Utilities Rates, Public Utilities Reports, Inc., Arlington, 1988, p. 491]

Meters and Services investment costs do vary with the number of customers--one customer, one Service and one Meter are required. Because Services and Meters meet the requirement that they are a function of the number of customers, and because Services and Meters do not perform a system function, I have classified and allocated Services and Meters on a customer basis. However, electric distribution facilities upstream of Meters and Services including poles, transformers, conductors and substations[1] are caused by the loads that are demanded, not to the number of customers. This is so because the very existence of these facilities relates to sufficient loads over which the costs can be amortized so as to warrant the incurrence of the costs by PPL in the first place, and the sizing of the facilities will be larger or smaller depending on the greater or lesser coincidence of those electric loads, respectively. Thus, Services and Meters, which are properly classified as a customer cost, do vary directly with the number of customers and exhibit no diversity of demand, are distinguished from Common Distribution facilities, which are built to meet the common diverse load requirements of PPL's customers.

Q. YOU MENTIONED THAT FACILITIES UPSTREAM OF SERVICES RELATE TO THE LOADS THAT ARE DEMANDED, NOT TO THE NUMBER OF CUSTOMERS. PLEASE EXPLAIN.

A. Customer costs vary uniquely with the number of customers. Using transformers as an example, a conclusion that transformers are a customer cost would require a finding that there is a unique relationship between an increase in the number of customers and the number of transformers. A distribution company like PPL may serve a single customer

[1] Poles, transformers and conductors are upstream of Services and Meters in the sense that electricity flows from its source through the Common Distribution system facilities, into the Services and on to the Meters.

with one transformer. Another transformer may serve two or three customers, four or five customers, or twenty or more customers, depending on the transformer size and the proximity of customers. Transformers are required when end-user loads are of sufficient duration so as to warrant the incurrence of costs, and transformers will be sized to meet the maximum coincident demand expected from the customers served from the transformer. Transformer facilities do not vary uniquely with the number of customers, but do relate to PPL's end-user load characteristics. This stands in direct contradiction to the requirement that customer costs vary uniquely with number of customers.

Transformers are required to meet customer load requirements at all times, including the peak demand placed on each transformer. There is no unique requirement to install a transformer for each customer, or for any given number of customers. However, all electricity delivered to customers must be transformed to usable voltages, and additional transformer costs are incurred to meet the coincident peak demands placed on each transformer. The peak demands on each transformer are caused by the coincidence of customer demands, or the lack of diversity of demands, not by the number of customers. Thus, transformers are needed, and transformer costs are incurred, to meet demands for delivered electricity whenever those demands occur, and transformers must be sized to also meet the coincident peak demands of customers served from each transformer.

Q. IS IT REASONABLE TO CLASSIFY DISTRIBUTION FACILITIES UPSTREAM OF METERS AND SERVICES AS A CUSTOMER COST AND ALLOCATE THE COSTS ON A CUSTOMER BASIS?

A. No. There is no demand for "connection" service. The demand for electricity is a derived demand, dependent on the customers' electricity using devices. Each customer brings with him or her a stock of electricity using devices and an average annual demand for electricity (which exhibits variance by season, day of the week, time of day, holiday/workday, weather features, etc.). If there are no devices, there is no demand for electricity, and no need to be a customer. Neither does PPL sell connection service. PPL's tariff does not include an offering for connection service, nor does PPL invest in phantom distribution facilities that would carry no load. PPL would not invest the hundreds of millions of dollars that it identifies as the cost it would incur to install a system that could carry no load. I believe it is reasonable to allocate costs on the basis of actual service units provided, rather than to allocate costs on the basis of phantom systems which would provide non-existent "connection" service -- a service for which there is no demand, nor is it a service which is offered. Moreover, PPL has determined that this phantom service would require substantial facilities and related costs -- costs which could not be recovered from the application of rates to non-existent service demands.

Q. IS THERE ANOTHER PROBLEM WITH THE HYPOTHETICAL CONSTRUCT OF A SO-CALLED CUSTOMER PORTION OF DISTRIBUTION SYSTEM FACILITIES UPSTREAM OF METERS AND SERVICES?

A. Yes. Determining the customer cost component of Distribution facilities on the basis of the minimum sized system produces a result that is both uncertain and arbitrary. Let me use transformer facilities as an example. In the PPL case prior to its 2004 rate case, PPL based its transformer customer cost determination on the costs of its 10 kVa transformers, and determined that the customer component of its line transformers was 23 percent of its line transformer investment. In its 2004 rate case at Docket No. R-00049255, PPL determined its line transformer customer component on the basis of its 30 kVa transformer investment and concluded the customer component was 63 percent of its line transformer investment. In the present case, PPL now bases its line transformer customer component on a 10 kVa transformer, includes an adjustment to address the capacity value, and concludes that the line transformer component is 53 percent of its transformer investment. Assuming *arguendo* the validity of extending the customer cost notion upstream of Services to include portions of PPL's major distribution facilities, clearly the proposed customer costs, at 23 percent, or 53 percent, or 63 percent, all based on the minimum sized system, are both uncertain and arbitrary. Moreover, different methods can be used to estimate so-called distribution customer costs, like the zero-intercept method, which would be expected to produce yet different conclusions regarding the customer component. These uncertain and arbitrary cost determinations do not provide the Commission with a reasonable, certain or reliable basis on which to determine how much revenue each class should provide in order to cover their reasonably allocated costs.

<u>The Misallocation of Primary Distribution Plant</u>

Q. TURNING TO PPL'S PRIMARY DISTRIBUTION COSTS, WHICH PPL ALLOCATES ENTIRELY ON THE BASIS OF CLASS PEAK DEMANDS, ARE ALL OF PPL'S PRIMARY COSTS OF SERVICE CAUSED BY CLASS PEAK DEMANDS WHICH OCCUR IN ONE OF THE 8,760 HOURS IN A YEAR?

A. No. Customer demands for electricity vary throughout the year reaching a maximum coincident peak demand sometime during the year. PPL distribution facilities exist, operate, and provide service throughout the year in order meet all demands throughout the year. Because extra costs are incurred to size the plant sufficiently to meet peak demands, as well as sustained demands, some costs are caused by the peak demands. PPL's large, fixed distribution costs would not exist if its customers had demands for electricity that existed only during the one peak hour each year. Thus, some costs are caused by PPL's sustained demands throughout the year, and some costs are caused by the maximum coincident demands. PPL's allocating all of its Primary Distribution costs, and all of its non-customer related Common Distribution costs on peak demands only vastly overstates the importance of the extra costs incurred to meet peak demands, and produces a significant misallocation of costs.

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

A. Based on my review of PPL's proposed cost study, I find that:

- *PPL improperly includes an allocation of its Common Distribution facilities and* related costs upstream of Services on a customer basis; and
- PPL's allocation of all of its Primary Distribution costs and the demand related portion of its Common Distribution costs entirely on the basis of class peak demands overallocates costs on the basis of peak demands resulting in a significant misallocation of costs.

I conclude that PPL's cost of service study results are an unreliable indicator of the adequacy of class revenue components as compared to allocated costs. The cost misallocations I have identified are significant and substantial. Distribution plant accounts that contain the misallocations I have discussed affect 88 percent of the total dollar value of PPL's distribution plant accounts. A class cost of service study compares each class' revenues to each class' allocated costs of service in order to assist in the determination of reasonable rates. Because PPL's major categories of costs have been improperly classified and misallocated, PPL's cost of service study results do not present a useful guide to the Commission for use in the setting of rates in this proceeding.

III. An Alternative Allocation of PPL's Common Distribution Plant

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

A. Yes. There are numerous cost study variants that can be used to allocate PPL's average, embedded, historic costs among PPL's several customer classes. Cost allocations will vary among these studies to address the concerns or to represent the differing views of cost practitioners performing the studies. For example, PPL has performed its 2007 class cost of service study in such a manner that it concludes that $1.0 billion dollars, or 44 percent of its total Common Distribution plant costs for overhead line, underground lines and line transformers, is customer related. Professor James Bonbright warns of using the customer cost category as a dump for the costs of minimum sized system. Professor Bonbright puts it this way:

> ...But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a <u>dumping ground</u> for costs that they cannot plausibly impute to any of their other cost categories. [Bonbright, James C., <u>Principles of Public Utility Rates</u>, Public Utility Reports, Arlington, VA, 1988, second edition, p. 492, emphasis added]

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

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

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

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

A. The demands for delivered electricity, both in annual amounts sufficient to warrant PPL's existence and in amounts that reflect maximum demands, cause the costs that PPL seeks to recover in this proceeding. These demands for electricity are what economists call "derived demands." Electricity is not demanded for its own sake; rather, electricity is demanded because people have a demand for things like warmed and cooled living and working spaces, refrigerated and frozen and cooked foods, warm water showers, clean and dried clothes, home and business video and audio entertainment or presentations, or the desire to see clearly at night, and in general, the use of all the other electricity-using appliances and equipment that are used to satisfy the revealed demands of market participants. The use of all these electricity-using appliances creates the demands for delivered electricity on PPL's system. These demands exist year-round, creating an annual demand for electric service.[2] Without this annual demand in sufficient amounts there would be no PPL costs of service because there would be no PPL electric distribution system. It is the sustained demand for electricity, which is ultimately responsible for PPL's existence and costs, which has been relieved of any cost responsibility by PPL in its proposals to allocate its total costs of providing service.

Now, if the annual demand for electricity delivered across PPL's distribution system were an absolutely level amount each day of the year and each hour of the day, PPL's distribution system would only have to be built to deliver this average hourly amount of capacity. A system designed to meet this constant average demand is the smallest sized system that could deliver the annual energy requirements of PPL's customers. But electricity demands are not constant. At times, the demands for the delivery of electricity are higher than at other times. PPL distribution company exists not only to service its customers' average delivery service requirements, but PPL must also stand ready to meet elevated delivery service requirements whenever they exist throughout the year. From this perspective it is the annual, or average service demands,[3] and the elevated, or peak demands, that cause PPL to incur its costs of providing service. Consistent with this practical, realistic view of PPL's delivery service operations (compared to PPL's view that its costs are driven by number of customers and their one-hour per year peak demands only) PPL's Primary and Common Distribution costs are

[2] When asked in Data Request OCA Set V, Q. 7 to list all residential electricity using devices that use electricity only at the time of class peak demands, PPL responded that to its knowledge, "there are no devices that use electricity only at the time of class peak demands."
[3] Average demands for service bear the same relationship as annual demands, since average demands are annual demands divided by a constant 8,760 hours.

related partially to PPL's customers' average demands for service and partially to customers' peak demands for service.

Q. IS THERE A COST STUDY VARIANT WHICH ALLOCATES COSTS ON THE BASIS OF CUSTOMERS' ANNUAL, OR AVERAGE, DEMANDS AND CUSTOMERS?

A. Yes, the Peak and Average cost study methodology allocates costs that are related to meeting customers' demands for electricity throughout the year on average demands, and allocates costs that are related to customers' peak demands that occur sometime during the year on the basis of peak demands. PPL's customers demanded 36,688,327 MWhs during its 2007 test year, or an average of 4,188 MWs during each of the year's 8,760 hours. PPL could not have met its customers' test year demands for electricity without incurring the costs associated with a system sized any smaller than a capability of 4,188 MWs. However, PPL's customers do not use electricity at a constant rate throughout the year. Instead, demands for electricity vary, establishing customer class demands that reached a maximum of 8,312 MWs. No smaller capacity than 4,188 MWs could deliver the annual requirement of PPL's customers, but PPL built its system to also meet its class peak demands of 8,312 MWs and incurred the additional costs caused by its coincident peak demands. Average demands account for 50.4 (4,188 MW/8,312 MW) percent of PPL's Distribution facilities, and peak demands account for 49.6 (100% - 50.4%) percent of PPL's Distribution facilities.[4] In other words, 50 percent of PPL's delivery capacity is required to provide for the delivery of PPL's average demands, while an additional 50 percent of PPL's delivery capacity is essential to the delivery of PPL's elevated, peak demands. Unlike PPL's customer/demand construct, the Peak and Average construct is

[4] In fact, one would clearly expect that additional capacity would cost less per unit than a smaller amount of capacity. That is, the costs associated with peak demand requirements would be less than the costs associated with lesser requirements. However, when performing an average cost of service study (as PPL does), each unit of capacity is valued at the same, identical average cost of capacity.

grounded in reality. The delivery of each customer class' annual, or average, requirements is not only a service that PPL provides, it is the overwhelmingly dominant service that PPL provides and is the main reason that PPL exists and functions as a delivery service company. Delivery service throughout the year is the service for which there is a demand, is the service that is included in PPL's tariff, and is the service that sells at prices that provide PPL with an opportunity to recover associated costs.

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

A. Because the Company said its cost of service model is proprietary, I specified the Peak and Average allocation factors to apply to PPL's Primary Distribution and Common Distribution plant, and PPL re-ran its cost study. Distribution costs and Common Distribution costs were allocated partially on the basis of class average demands and partially on the basis of class peak demands. Those study results are based on 50 percent weighting of average demands and a 50 percent weighting of peak demands. Theoretically, the capacity required to deliver average demands could properly be based on the ratio of average demands to peak demands, which is simply the definition of system load factor, because no smaller system capacity could deliver the annual demands for electricity on the PPL system. PPL has a system load factor in excess of 50 percent, but the studies utilized a weighting of average demand cost responsibility at 50 percent so as to present a conservative restatement of costs that are caused by the annual, or average, demands for electricity by PPL's customers. Because PPL's Primary and Common Distribution plant must be sized to not only accommodate PPL's average demands, but to also deliver electricity at times of peak demand, the remaining Primary and Common Distribution plant costs have been allocated on class noncoincident peak demands.

Q. WAS THERE A PROBLEM WITH THE COST OF SERVICE STUDY RUN THAT PPL PREPARED FOR YOU?

A. Yes. Some secondary distribution costs were inadvertently allocated to customers taking service at primary voltages. The study I requested is being re-run to correct this problem.

Q. CAN YOU COMPARE THE RESIDENTIAL RS CUSTOMER COST STUDY RESULTS PRODUCED BY YOUR ALTERNATIVE COST STUDY TO THE RESULTS FOUND IN PPL'S COST STUDIES.

A. When costs are allocated on the basis of the service requirements which drive, or cause the costs to be incurred, including average demands and elevated demands as explained above, the cost misallocations inherent in PPL's studies are eliminated. The PPL study, based on the hypothetical no-load customer costs and the failure to ascribe any cost responsibility to the basic service PPL provides, i.e., annual electricity delivery service, shows substantially lower Residential RS index returns of only 59.4 percent and 81.6 percent, respectively. I will provide more data on residential customer and other customer rates of return when I receive the corrected cost of service study run.

IV. <u>Revenue Allocation</u>

Q. HOW HAS PPL PROPOSED TO UTILIZE ITS COST OF SERVICE STUDY RESULTS TO SPREAD ITS PROPOSED REVENUE INCREASE IN THIS CASE?

A. PPL generally proposes class revenue increases which move each class half way toward closing the difference between allocated costs and class revenues. Under PPL's proposals, for example, Residential RS customers would be allocated a $77,329,000

Distribution service rate increase, or 20.5 percent, compared to an overall Distribution service increase of $83,521,000, or 13.2 percent, because PPL's study shows an index rate of return for RS customers of only 59.4 percent at present rates.

Q. WHAT REVENUE SPREAD PROCEDURES DO YOU RECOMMEND?

A. I agree with PPL's 50 percent rule for use in this proceeding, adjusted so no class pays more than twice the system average. The remaining question is which cost study should be adopted for application of this rule.

The choice of cost studies at this point is the adoption of either PPL's Customer/Demand study or my own Peak and Average study. PPL's study allocates one billion dollars, or essentially one-half of its Distribution common facilities on the basis of a non-existent, hypothetical, phantom, no-load system for which there is neither a demand nor a corresponding tariff service offering. The minimum sized system measurement of this so-called customer component produces results that are widely variable, uncertain and arbitrary. Importantly, PPL allocates no costs on the basis of its customers' average demands, which is the overwhelmingly dominant, primary service requirement that PPL provides. I do not believe PPL's study reasonably allocates costs to customers utilizing the delivery service PPL provides.

This contrasts to the Peak and Average cost study which allocates costs on the basis of the service requirements which directly result in PPL incurrence of cost -- the average demands for electricity throughout the year, and the peak demands which require additional costs to be incurred. I recommend adoption of the Peak and Average cost study as the more reasonable indicator of class allocated cost responsibility. If the Commission bases its revenue spread determination on one cost of service study, I believe the study that most reasonably allocates PPL's Distribution costs by service is the Peak and Average cost study.

Q. ARE THERE ANY CONCERNS WITH PPL'S PREPARATION OF THE PEAK AND AVERAGE COST STUDY?

A. Yes. As I discussed, I received the Peak and Average cost study run at remand rates on Friday, June 29. While investigating the reasons for the differences in PPL's customer/demand study results and the PPL performance of the Peak and Average study, I discovered that PPL apparently and inadvertently allocated secondary costs of service to its customers who receive service at primary voltages. I have discussed this with PPL, and have requested a corrected PPL study. PPL will attempt to provide a corrected cost study by close of business, July 6. Upon receipt of a corrected cost study, I will submit Schedules RAG-1, -2 and -3 as soon as possible reflecting the corrected cost allocations.

Q. WHAT REVENUE SPREAD WILL YOU PROPOSE?

A. The schedules will show recommended class cost responsibilities consistent with the principles of moving classes one-half way toward cost of service, and limiting classes to no more than twice the average increase. Generally, these recommendations can be expected to reduce the proposed increases for classes containing large numbers of customers, and increase rates for classes that use large amounts of energy.

Q. SHOULD THE COMMISSION AUTHORIZE LESS THAN PPL'S FULL REQUEST, WHAT DO YOU PROPOSE?

A. Should the Commission authorize a lower total cost of service than PPL proposes, each class rate increase, as will be shown on RAG-3, should be scaled back accordingly. Alternatively, PPL could be required to re-run the Peak and Average cost study to comply with the Commission findings, and apply the 50 percent rule during the compliance phase of this proceeding.

Q. YOU MENTIONED THAT IF A COST STUDY IS ADOPTED, YOUR PEAK AND AVERAGE STUDY IS THE MOST REASONABLE. ARE AVERAGE,

EMBEDDED, ALLOCATED, CLASS COST OF SERVICE STUDIES CAPABLE OF YIELDING RESULTS THAT ARE SO PRECISE THAT THEIR RESULTS SHOULD BE DEEMED DEFINITE?

A. No. Cost of service studies are not an exact science and are often referred to as more art than science. For example, the bulk of PPL's costs are fixed costs. The allocation of fixed costs is controversial, largely because in the short-run, these costs may not change with the provision of a little more or less service. Regarding the allocation of fixed customer costs, Bonbright puts it this way:

> The really controversial aspect of customer-cost computation arises because of the cost analyst's frequent practice of including, not just the costs than can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system - a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. [Ibid., p. 491, emphasis added]

Also, regarding capacity related costs, the NARUC Manual, at page 23 states:

> Dr. James Bonbright, whose Principles of Public Utility Rates is the classic examination of regulation and ratemaking, wrote:
>
>> "Of all of the many problems of rate making that are bedeviled by unresolved disputes about issues of fairness, the one that deserves first rank for frustration is that concerned with the apportionment among different classes of consumers of the demand costs or capacity costs....Here, notions of 'fair apportionment' are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves, neither stable nor uniform, although they reveal a general tendency in favor of a fairly wide spreading out of costs, as butter would be spread over bread in a well-made sandwich. Awareness of these unresolved conflicts about 'fair' cost apportionment has lead the British economist Professor W. Arthur Lewis to exclaim that, in rate determination, 'equity is the mother of confusion.'"

Dr. Bonbright also includes the following regarding the allocation of capacity, or demand related costs:

> We come now to that category of costs, capacity, ready to serve, or demand costs, the treatment of which has made a nightmare of utility cost analysis (for two masterly theoretical treatments see Boiteux, 1960, and Crew and Kleindorfer, 1986). As the FERC *Handbook* (1983, p. 139) states: "For the problem which it presents is that of imputing joint costs to joint products or byproducts, and not merely that of distributing those common, but nonjoint, costs (See Chapter 2) which vary more or less continuously with number of consumers or with rates of output....
>
> Here, as with the other two categories of cost, there is no general agreement as to what items or portions of total costs should be included among the demand-related costs, perhaps because cost functions are far too complex to be reflected by the arbitrary, three-way classification of customer, energy, and demand....
>
> In attempting to assess these relative responsibilities, the analyst is offered a wide variety of alternative formulas of apportionment, each of which has received support from some rate experts. Testifying before the ICC in Illinois (1953) in a rate case, Corey noted the existence of twenty-nine such formulae; in their textbook Garfield and Lovejoy (1964, p. 159) mention "20 or more allocation methods"; and Grainger (1972, 1976) discusses several methods of allocating the ready-to-serve costs. Most of them have no claim whatever to validity from the standpoint of cost determination and only a dubious claim to acceptance as compromise measures of reasonable rates. A harsher critic might use the metaphor of Bentham that these claims are "nonsense upon stilts". [Ibid., pp. 494-495]

I conclude that allocated cost of service study results based on often controversial cost allocations are themselves controversial. Allocated costs of service are one component of information available for the Commission as it considers its affirmative responsibility to set just and reasonable rates. The controversial aspect of fixed cost allocations reinforces the general regulatory principle that cost of service results are often used as a guide to the setting of rates.

Q. IS IT APPROPRIATE TO REQUIRE THAT CLASS REVENUE RESPONSIBILITIES MUST BE SET EXACTLY EQUAL TO THE RESULTS

OF A SINGLE, ALLOCATED, EMBEDDED, HISTORIC, ACCOUNTING COST OF SERVICE STUDY?

A. No. While such a prescription would lead to index rates of return equal to 100 percent, revenue-to-allocated cost ratios of 1.0, and revenue minus allocated cost differences of zero, in my opinion, this prescription is neither necessary nor desirable. First, this revenue allocation prescription would produce a slavish, mechanistic basis for the setting of rates to the exclusion of all other cost and non-cost considerations. This conflicts with the long-standing Commission policy of using allocated cost study results as a guide to the setting of rates. Second, this prescription implies a precision and a lack of allocated cost controversy that simply does not exist. The very existence of numerous cost study variants and the controversial nature of various cost allocations reinforces the use of cost studies as guides to the setting of rates. I will include the range of results yielded by the Peak and Average cost study and PPL's customer/demand study when I receive the corrected Peak and Average cost study run.

Q. YOU HAVE EARLIER CITED PROFESSOR BONBRIGHT'S COMMENTS REGARDING THE DIFFICULTIES ATTENDANT TO THE ALLOCATION OF FIXED COSTS, THE MANY AND VARIED METHODOLOGIES THAT ARE USED TO ALLOCATE FIXED COSTS, AND THE CONTROVERSIAL NATURE OF FIXED COST ALLOCATIONS. WHAT DOES PROFESSOR BONBRIGHT SAY ABOUT THE EXTENT TO WHICH FULLY ALLOCATED, AVERAGE, EMBEDDED, HISTORIC ACCOUNTING COSTS OF SERVICE SHOULD BE USED AS A STANDARD AGAINST WHICH CLASS REVENUES MAY BE DETERMINED?

A. When addressing capacity related embedded cost allocations, Professor Bonbright states,

> Should the capacity costs be assigned to the different ratepayers on the basis of system peak responsibility, of coincident class demand, or any one of the other thirty-odd proposed bases of assignment to be found in the literature of rate theory? Here, notions of fair apportionment are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves neither stable nor uniform, although they reveal a general tendency in favor of a fairly wide spreading out of the costs, as butter would be spread over bread in a gourmet's sandwich. [Ibid., p. 184]

A standard that is best described as the wide spreading of costs as butter would be spread over bread in a gourmet's sandwich hardly supports a finding that class revenue responsibilities should be set entirely on the basis of and consistent with costs allocated in accord with the standard. Unfortunately, such is the nature of allocated, fully distributed cost of service findings.

Q. DOES YOUR FINDING THAT A PRESCRIPTION TO SET CLASS REVENUES AT RESULTING ALLOCATED COSTS IS NOT WARRANTED MEAN THAT CLASS COST RESULTS MAY NOT BE CONSIDERED IN THE RATE SETTING PROCESS?

A. No. In this present case, for example, my own study, the fully complete Peak and Average study, will demonstrate that PPL's cost of service study over-allocates costs to residential customers. While specific cost study results should not be slavishly converted into rates by rate application of simple arithmetic, cost studies which most reasonably allocate costs may be used as guides to the setting of rates.

V. **Rate Design**

Q. PLEASE DESCRIBE PPL'S PROPOSED RESIDENTIAL RS RATE DESIGN CHANGES.

A. Below is a comparison of PPL's present and proposed Residential RS rates shown on PPL's Exhibit Regs § 53.53, Part IV, Attachment IV-C, page 1.

	Present Rate	**Proposed Rate**
Distribution Charge	$7.96	$10.00
First 200 kWh	2.183¢	3.010¢
Next 600 kWh	1.975¢	2.500¢
Over 800 kWh	1.855¢	1.742¢

The proposed Distribution charge rate increase of $2.04 represents a 25.6 percent increase compared to a proposed residential RS Distribution service increase of 20.1 percent. PPL proposes a 38 percent first-block rate increase, a 15 percent second-block rate increase, and a 6 percent tailblock rate reduction. The tailblock price discount compared to middle-block consumption under proposed rates is a 30 percent discount compared to the current tailblock discount of 6 percent.

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

Yes. Schedule RAG-4 shows the determination of PPL's customer costs that are eligible for inclusion under my understanding of Commission precedent. In Pennsylvania, customer costs included in a monthly fixed charge, such as PPL's Distribution Charge, include return, taxes on return, and depreciation on services plant and meter plant. The return and taxes costs are $41.5 million, as shown on Schedule RAG-4. Other fixed costs included in the Distribution Charge are the $10.1 million and $10.8 million of depreciation expense on Services and Meters plant. Also considering variable O&M costs included in the Distribution Charge, as shown on Schedule RAG-4, results in total Distribution Charge costs of $96.8 million. Utilizing the costs shown on Schedule RAG-4, the calculated monthly Distribution Charge would be $6.76. A more economically meaningful Distribution Charge price signal would exclude the fixed costs, or depreciation expense and return and taxes, from the Distribution Charge determination.

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

A. For illustrative purposes and a direct comparison to PPL's proposed rates, I show below a Residential RS rate design consistent with PPL's proposed $449,866,498 Residential RS Distribution Rate Revenue shown on Attachment IV-C, page 1 of Mr. Kasper's attachments.

	Present Rate	**OCA Proposed Rate**
Distribution Charge	$7.96	8.00
First 200 kWh	2.183¢ per kWh	2.744¢ per kWh
Next 600 kWh	1.975¢ per kWh	2.536¢ per kWh
Over 800 kWh	1.855¢ per kWh	2.416¢ per kWh

The $8.00 Distribution Charge essentially maintains PPL's current rate, which exceeds my understanding of Pennsylvania Commission precedent on this issue. All other block rate prices have been increased by the same absolute 0.561 cents per kWh amount. These proposed rates are consistent with PPL's current three-block rate design. The proposed, equal, absolute 0.561 cents per kWh increase is consistent with average, embedded cost of service study results. These cost of service studies do not determine costs by consumption level.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED TIME OF USE PRICING PROGRAM.

A. As a Demand Side Management offering, PPL proposes to develop time of use pricing proposals for use by its residential and small business customers under pilot programs. Time of use pricing would be developed and implemented in the 2008-2009 time frame. Pricing options under consideration are Day Ahead, Real Time, and Critical Peak pricing. Purposes of the Time of Use Pricing program include educating customers about market price volatility, understanding demand response behaviors, and gathering information regarding the demands and issues related to facilitating demand responses to time-varying prices. Customer participation in the program will be limited during the development period.

Q. AS THE TIME OF USE PRICING PROGRAM IS DEVELOPED AND IMPLEMENTED, COULD YOU GIVE A FEW EXAMPLES OF THE KINDS OF MATTERS THAT NEED TO BE CONSIDERED UNDER THE PROGRAM?

A. Numerous programmatic decisions will attend the development and offering of yet-to-be developed rates and terms of service under pilot time of use pricing schemes. A few of the considerations under a time of use pricing program would include:

-- the voluntary nature of participation;

-- pilot program participation limits and how participants will be selected;

-- if inducements are required to gain participants, what inducements will be offered, and how will the inducements be structured so as to achieve their objective and not adversely affect pricing signals to be studied?

-- what special equipment may be needed for participation, and who will bear the cost of the equipment?

-- what pricing elements will be included in the various offerings?

-- what revenue targets make the most sense for program participants?

-- how will pricing periods be defined under the various offerings?

-- length of the pilot programs;

-- on-going and final evaluation criteria; and

-- pilot program sunset arrangements.

The answer to these and to other questions and issues at the commencement of the Time of Use Pricing program and throughout the program will affect the ultimate usefulness of the program and the participants in the program. The main purpose of the program is a learning tool for both the company and its customers. The structure of the program is obviously of critical interest to all those who will both participate in the program and who are part of the population that will ultimately be affected by the program results.

Q. WHAT DO YOU RECOMMEND?

A. If the Time of Use Pricing program is approved by the Commission, I recommend that PPL be ordered to adopt procedures that provide for the OCA's and other interested parties' participation through systematic inclusion in all aspects of initial and on-going rate development. The Company should work cooperatively with the OCA and other interested parties regarding the issues being considered, the progress and options addressing the issues, problems being encountered, basis of proposed rate development and implementation recommendations, etc. Periodic meetings related to program considerations and development should be conducted. I believe that this would be in the best interest of PPL and its customers.

Q. PPL HAS PROPOSED TO RECOVER ITS ESTIMATED $2.7 MILLION DSM COSTS THROUGH THE APPLICATION OF A RECONCILABLE SURCHARGE. DO YOU AGREE?

A. No. DSM costs should be recovered through base rates. DSM costs are neither extremely volatile, like fuel costs, or outside of utility management control, like taxes.

Because the timing and unfolding activities under the proposed DSM program are uncertain at this time, however, as explained by PPL witness Robert T. Homa, PPL should be required to submit periodic scheduled reports to the Commission and to the parties on the costs and benefits it incurs under its DSM program.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. No, I will file supplemental direct testimony after receipt from PPL of the corrected Peak and Average cost of service study.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	DOCKET NO. R-00072155
PPL ELECTRIC UTILITIES CORPORATION	)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

JULY 6, 2007

EXETER

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

Schedule RAG-4

PPL Electric Utilities Corporation
Distribution (Customer) Charge Determination
Residential RS
$000's

Electric Plant			Cost
Services	$444,156		
Meters	176,390		
		$620,546	
Depreciation Reserve			
Services	$225,606		
Meter	57,979		
		$283,585	
Net Customer Plant		$336,961	
Pre-tax rate of return		12.34%	
Return & taxes			$41,581
Depreciation Expense/Services			10,105
Depreciation Expense/Meters			10,821
O&M			
Services			3,869
Meters			7,808
Meter Reading			2,728
Collection Expense			8,250
Other Customer Accts Exp			8,543
Employee Benefits @ 10% of O&M			3,120
Total Cost			$96,825
Customer Bills (12 x 1,193,921)			$6.76/Cust/mo.

OCA Statement No. 3S

Hbg-TK AUG 16 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCUMENT FOLDER

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	DOCKET NO. R-00072155
PPL ELECTRIC UTILITIES CORPORATION	)	

DOCKETED SEP 7 - 2007

SURREBUTTAL TESTIMONY

OF

RICHARD A. GALLIGAN

RECEIVED

AUG 17 2007

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

AUGUST 2007

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

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

RECEIVED
AUG 17 2007
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	DOCKET NO. R-00072155
PPL ELECTRIC UTILITIES CORPORATION	)	

SURREBUTTAL TESTIMONY OF RICHARD A. GALLIGAN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. ARE YOU THE SAME RICHARD A. GALLIGAN WHO FILED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to comment on the rebuttal testimony of a number of witnesses who addressed various cost allocation and rate design topics. Witnesses whose rebuttal testimony I address include Messrs. Oliver G. Kasper and Joseph M. Kleha on behalf of PPL Electric Utilities Corporation ("PPL" or the "Company"). I also respond to the rebuttal testimony of Mr. Robert D. Knecht on behalf of the Pennsylvania Office of Small Business Advocate, and Mr. Stephen J. Baron on behalf of PP&L Industrial Customer Alliance. My surrebuttal testimony responds to the cost allocation and rate design issues addressed by these witnesses. I will respond to common themes addressed by several witnesses on an issue basis, rather than repeat responses separately for each witness.

Cost of Service Issues

Q. MR. KLEHA, AT PAGE 3 OF HIS REBUTTAL TESTIMONY ARGUES THAT, UNLIKE YOUR COST OF SERVICE STUDY, PPL'S STUDY IS A MORE MODERATE, MIDDLE-OF-THE-ROAD STUDY. IS MR. KLEHA CORRECT?

A. No. At page 3 of his rebuttal testimony, Mr. Kleha testifies:

> Second, the only party in this proceeding who criticizes PPL Electric's cost allocation study is Mr. Galligan, on behalf of the Office of Consumer Advocate. Mr. Galligan proposes changes which, if adopted, would reduce the level of costs assigned to the residential class. The Company however, seeks to take a more moderate middle-of-the road position regarding the allocation of costs to the various customer classes and, as such, does not favor one customer class over another when assigning costs."

Mr. Kleha is incorrect when he says my proposed changes reduce the level of costs only for the residential class. Allocated costs are also less for the GS-1 customers. More to the point, my study more accurately reflects system cost causality. Mr. Kleha does not apply the same test to those supporting his model who benefit greatly from the misallocation of costs. Mr. Kleha states on page 3 of his rebuttal testimony:

> The Office of Small Business Advocate, the Department of Defense, and the PPL Industrial Customer Alliance, which represent commercial and industrial customers, all support PPL Electric's cost allocation study.

It is in the pecuniary interest of every one of these intervenors to support PPL's cost allocation study which "if adopted would reduce the level of costs assigned to" their respective classes compared to the study I present. There are not three studies available in the record in this proceeding with PPL's representing a "middle ground." There are only two studies, the Peak and Average study and the customer/demand study. I believe it is better to determine which study more reasonably allocates costs to the services that cause the costs, than to afford any weight to PPL's erroneous assertions that because its study is supported by all the parties who would gain from its acceptance, the PPL study is the more moderate.

Q. MR. KLEHA ARGUES ON PAGE 24 OF HIS REBUTTAL TESTIMONY THAT PPL HAS USED THE SAME FUNDAMENTAL ALLOCATION METHODOLOGY IN PRIOR RATE PROCEEDINGS AND CONSISTENCY IS IMPORTANT. PLEASE RESPOND.

A. In contrast to his consistency argument, Mr. Kleha also states that *Lloyd* has made the fundamental principle of cost causation more important. I agree. But, contrary to Mr. Kleha, I believe that the unbundling and restructuring of PPL's operations makes it more important to get it right when it comes to the allocation of distribution costs. The NARUC-commissioned RAP Report puts it this way:

> Efforts to restructure the electric industry, to create competitive markets for generation and retail services, have, in a sense, "uncovered" the distribution system and have encouraged utilities, consumer advocates, and regulators to re-examine pricing policies for what appears to remain a naturally monopolistic component of the industry. (The same can be said of transmission; however, our focus is on that part of the system that falls primarily under state jurisdiction.) The distribution network, which typically had accounted for anywhere from ten to forty percent of a vertically-integrated utility's total investment, has thus become the object of central concern to firms that no longer own generation assets. Recent utility proposals to restructure distribution rates can be seen as business strategies to mitigate risk and increase revenues, understandable in themselves but not necessarily consistent with the overall public interest. [Ibid., p. 6]

Blind adherence to "consistency" in the newly unbundled and restructured operating scheme does not seem to be supported by the changed circumstances drastically altering the utility service subject to state regulation.

Moreover, PPL has changed its cost allocation methodology. In PPL's prior case, I argued that PPL's so-called customer cost determination was improper because of the capacity costs included in its customer classified costs. PPL argued against this view in its 1995 and its 2004 rate cases. In the present case, PPL, of its own volition, changed its cost allocation methodology, contrary to "consistency" and prior Commission precedent, and adjusted its proposed customer classifications cost in an attempt to eliminate capacity costs included in its "minimum system" customer costs. Clearly, it is inconsistent for PPL to argue that other parties should be bound by "consistency" considerations, when PPL itself is not.

Q. AT PAGES 9 AND 10 OF HIS REBUTTAL TESTIMONY, MR. KLEHA PRESENTS THREE ENUMERATED ARGUMENTS AS TO WHY HE BELIEVES ALLOCATING DISTRIBUTION COSTS UPSTREAM OF METERS AND SERVICES ON THE BASIS OF PEAK AND AVERAGE DEMANDS IS INAPPROPRIATE. PLEASE COMMENT.

A. Mr. Kleha's first enumerated argument is that there is simply no rational basis for opposing the principle that distribution costs are incurred to "connect" customers. I have presented the basis of allocating common distribution costs (related to facilities upstream of meters and services) partially on annual, or average, demands and partially on peak demands at pages 15-19 of my direct testimony, and at pages 3-5 and pages 9-10 of my rebuttal testimony. Suffice it to say here that PPL is not in the business and will not extend its facilities to "connect" customers. PPL is in the business, and will extend services to acquire new annual delivery service electric load requirements. Each customer brings its loads along with it, and PPL incurs costs to extend its system and acquire and serve the new load requirements. No loads -- no extension. It is the existence of loads that cause costs, not the existence of customers who have no load requirements.

Mr. Kleha's second-stated argument has commonality to arguments also advanced by Messrs. Knecht and Baron, which I will address later in my rebuttal testimony.

Mr. Kleha's third-stated argument is that distribution facilities do not vary based on the amount of energy consumed by customers; rather, distribution facilities are sized to meet peak demands. I explain at pages 16-19 of my direct testimony the portion of costs that is related to average demands and the portion of costs that is related to serving peak demands. Indeed, there are greater costs incurred to deliver electricity when demanded at peak demand rates compared to the costs of meeting lesser, average demands. The Peak and Average methodology accounts for this, assigning 50 percent of PPL's common distribution facilities and related costs on a peak basis. Mr. Kleha is wrong when he concludes that a large portion of costs is incurred to "connect" customers; that no costs are related to PPL's primary service obligation -- the delivery of electrical energy whenever, over the course of a year, customers demand electricity; and that all remaining non-customer costs are caused by one-hour demands each year. It is simply inconceivable that no costs are associated with, related to, or caused by, the primary, essential service that PPL exists to provide.

Q. AT PAGE 10 OF HIS REBUTTAL TESTIMONY, MR. KLEHA TESTIFIES THAT AVERAGE DEMANDS SHOULD NOT BE USED TO ALLOCATE COSTS BECAUSE ENERGY SALES DO NOT DEFINE THE DESIGN OF THE DISTRIBUTION SYSTEM. PLEASE RESPOND.

A. Here Mr. Kleha is restating his belief that none of the total delivery costs PPL incurs to provide its main product -- delivery of electricity whenever it is demanded -- are related to the provision of this main product. In Mr. Kleha's view, all of PPL's demand costs relate to and are incurred to provide service during the one-hour of class peak demands. There is no controversy over the capability of PPL's distribution system to deliver peak demands. The question is, are peak demands the cause of all of PPL's demand related costs?

While customers establish one-hour peak demands during a year consisting of 8,760 hours, it is clear that the PPL distribution system would not exist if electricity delivery service were demanded only one-hour per year. PPL concedes that the demand requirements on its system are not limited to one or a few hours per year, responding to OCA Data Request Set v, Q. 7, "there are no devices that use electricity only at the time of class peak demands." Thus, there are costs related to meeting the sustained demands, which are responsible for the existence of PPL's electric distribution system, and there are costs associated with meeting peak demands. The Peak and Average cost allocation methodology allocates costs both to the sustained demands that cause PPL to exist, and to the peak demands that cause distribution system costs to be higher than they would be absent variations in demand.

Q. AT PAGE 11 OF HIS REBUTTAL TESTIMONY, MR. KLEHA TESTIFIES THAT THE NARUC COST ALLOCATION MANUAL ("NARUC MANUAL") ON PAGE 90 "DEFINES A MINIMUM SIZE DISTRIBUTION SYSTEM AS THAT BASED ON THE SMALLEST SIZE EQUIPMENT CURRENTLY BEING INSTALLED BY THE UTILITY." IS THIS STATEMENT DISPOSITIVE OF THE ISSUE OF WHAT COSTS MAY BE USED TO DETERMINE SO-CALLED CUSTOMER COSTS?

A. No. The material referred to by Mr. Kleha is selective. Discussing minimum size method at page 95, the NARUC Manual alerts the reader to size considerations attendant to the method:

> The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently being installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Clearly, the NARUC Manual does not dictate exactly which method a cost analyst might use if the customer cost notion is going to be applied to facilities upstream of meters and services, and if the minimum size method is utilized.

Q. AT PAGE 13 OF HIS REBUTTAL TESTIMONY, MR. KLEHA TESTIFIES THAT YOU SEEM TO SUGGEST THAT THE ZERO INTERCEPT METHOD IS BETTER THAN THE MINIMUM SIZE SYSTEM METHOD. AT PAGE 13, MR. KLEHA TESTIFIES THAT YOU PROPOSE TO ADJUST THE COMPANY'S ALLOCATORS BECAUSE THE EQUIPMENT USED IN THE MINIMUM SIZE SYSTEM HAS SOME LOAD CARRYING CAPABILITY. PLEASE RESPOND.

A. I do not make any superiority claim for the zero-intercept method, nor do I testify that PPL's determination of so-called customer costs in this proceeding need to be adjusted because the minimum size system has some load-carrying capability. I recognize that PPL has considered the load-carrying capability of the minimum size system, and it has proposed an adjustment to address this concern. While Mr. Kleha's adjustment addresses the problem that minimum sized facilities are capable of meeting demands, the adjustment does not validate the notion that PPL incurs costs to "connect" customers compared to the fact that PPL will incur costs to acquire customer loads.

Q. AT NUMEROUS PLACES IN THEIR TESTIMONY, MESSRS. KLEHA, BARON AND KNECHT CITE THE NARUC MANUAL FOR AUTHORITY FOR UTILIZING THE CUSTOMER COST NOTION TO ALLOCATE COSTS UPSTREAM OF METERS AND SERVICES, AND THEIR ENSORSEMENT OF PPL'S MINIMUM SIZE METHOD TO MAKE THOSE ALLOCATIONS. PLEASE COMMENT.

A. Mr. Kleha appeals to the NARUC Manual in his rebuttal testimony at page 9, lines 7-16; page 11, lines 12-22; and page 12, lines 5-7. Mr. Knecht appeals to the NARUC Manual in his rebuttal testimony at page 11, lines 14-18; and page 16, line 28 through page 17, line 12. Mr. Baron appeals to the NARUC Manual in his rebuttal testimony at page 4, line 11 through page 5, line 16; page 7, lines 1-17; page 10, lines 7-13; and page 11, line 18 through page 12, line 4. Appeals to the NARUC Manual for authoritative support for any one particular cost classification or allocation method are vain.

A major objective of the Manual, one of three objectives discussed in the NARUC Manual's Preface, is stated as follows:

> The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons. [NARUC Manual, p. ii]

The NARUC Manual is expository, using simple declarative language. It is a how-to manual. It does not endorse, recommend or judge the cost allocation methods it presents, as revealed in the referenced statement embodying this principle.

Q. MR. BARON, IN HIS FOOTNOTE 2 ON PAGE 10 OF HIS REBUTTAL TESTIMONY STATES THAT YOU RECOMMEND AN ARBITRARY 50/50

WEIGHTING BETWEEN DEMAND AND ENERGY AS YOU APPLY THE PEAK AND AVERAGE METHOD TO PPL, AND THAT THIS CONTRASTS WITH YOUR WEIGHTING OF THE ENERGY PORTION OF YOUR ALLOCATIONS BY THE SYSTEM LOAD FACTOR IN THE RECENT DUQUESNE LIGHT COMPANY CASE. PLEASE COMMENT.

A. Theoretically, the capacity required to deliver average demands could properly be based on the ratio of average demands to peak demands, which is simply the definition of load factor. At page 18 of my direct testimony, I report that PPL's retail jurisdictional load factor is 50.4 percent. The Peak and Average cost studies reported in Schedule RAG-1 Supplemental weight average demand responsibility at PPL's 50 percent rounded load factor. It is not accurate to refer to this 50 percent weighting of average demands as arbitrary.

Q. AT PAGE 6 OF HIS REBUTTAL TESTIMONY, MR. BARON OPINES, "THE CONCEPTUAL BASIS FOR THE MINIMUM SIZE METHOD IS THAT IT REFLECTS A CLASSIFICATION OF THE DISTRIBUTION FACILITIES THAT WOULD BE REQUIRED TO SIMPLY INTERCONNECT A CUSTOMER TO THE SYSTEM, IRRESPECTIVE OF THE KW LOAD OF THE CUSTOMER. FROM A COST CAUSATION STANDPOINT, THE ARGUMENT SUPPORTING THIS APPROACH IS THAT ALL OF THESE MINIMAL FACILITIES WOULD BE REQUIRED SIMPLY DUE TO THE REQUIREMENT TO INTERCONNECT THE CUSTOMER...." PLEASE COMMENT.

A. PPL has no requirement to "connect" customers irrespective of load. PPL will extend its system and incur related costs to attach loads that are permanent, for which there is no doubt of continued use of the new facilities by the customer, and the extension is non-speculative. That is, PPL will incur costs to provide delivery service for sustained demands, and to meet peak demands as well as average, or annual, demands. PPL is not obliged to incur costs (without a compensatory one-time customer contribution or a customer revenue guarantee) to "simply" hook up a customer irrespective of the customer's demand for electrical energy.

Q. AT PAGE 7 OF HIS REBUTTAL TESTIMONY, MR. BARON STATES, "THE NARUC MANUAL DOES NOT EVEN MENTION MR. GALLIGAN'S PREFERRED METHOD, 'PEAK AND AVERAGE,' FOR ALLOCATING DISTRIBUTION COSTS." AT PAGE 17 OF HIS REBUTTAL TESTIMONY, MR. KNECHT, TOO, SAYS THAT NARUC MANUAL DOES NOT CITE THE P&A APPROACH AS A STANDARD APPROACH. PLEASE RESPOND.

A. A number of peak and average methods are illustrated in Chapter 4, Embedded Cost Methods for Allocating Production Costs, in the NARUC Manual. The NARUC Manual includes reference to the peak and average method at page 41:

> Energy weighting methods include the average and excess method, equivalent peak method, the base and peaker method, and methods using judgmentally determined energy weighting, such as the peak and average method and variants thereof.

As I mention later in my surrebuttal testimony, the NARUC Manual includes the classification of costs on an energy basis. Having discussed various peak and average methods in Chapter 4, the NARUC Manual authors chose not to repeat the discussion in Chapter 6, Classification and Allocation of Distribution Plant.

Q. IS THERE EVIDENCE THAT PPL'S PLANNING CRITERIA ENCOMPASSES MORE THAN PROVIDING FOR ITS PEAK DELIVERY DEMANDS?

A. Yes. At page 8, lines 4-8 of Mr. Kleha's rebuttal testimony, he states:

> It also should be noted that PPL designs and plans its distribution systems to operate safely and efficiently. As such, this system is planned and designed to <u>maintain</u> a proper balance between <u>service reliability</u> and the cost of providing that service, and to avoid large-scale, long-term or to <u>avoid large-scale, long-term or frequent interruptions</u> because of the adverse effects on and hazards to the public. [Emphasis added]

Maintaining service reliability is a year-round function, not a peak-related function, and certainly not a "customer-related cost" (since the customer facilities can deliver no energy anyway, reliability considerations are moot). Similarly, avoiding large-scale, long-term or frequent interruptions is important throughout the year, not just at the one hour of class peak demands. The goals of planning and designing (and operating) a system to provide reliable service and avoid large-scale, long-term, uninterrupted service throughout the year are clearly related to meeting annual service requirements, not just peak requirements, and certainly are not applicable at all to "phantom," no-load minimum system requirements.

Q. AT PAGE 9 OF HIS REBUTTAL TESTIMONY, MR. BARON OPINES THAT THERE IS NO "LEGITIMATE 'CONTROVERSY' AS TO THE PORTION OF [DISTRIBUTION FACILITIES UPSTREAM OF METERS AND SERVICES] THAT ARE RELATED TO A CUSTOMER'S KWH ENERGY USE BECAUSE A CUSTOMER'S KWH USAGE DOES NOT INFLUENCE THE UTILITY'S DECISIONS TO INCUR DISTRIBUTION COSTS. MR. KLEHA ALSO TESTIFIES AT PAGE 9 OF HIS REBUTTAL TESTIMONY THAT THERE IS NO ENERGY PORTION OF DISTRIBUTION-RELATED COSTS. PLEASE RESPOND.

A. Mr. Kleha, in discussing his second enumerated argument against using the Peak and Average method to allocate costs testifies at page 9 of his rebuttal testimony that "The

NARUC Manual does not state, or even suggest, that any portion of an electric utility's distribution-related facilities should be assigned or allocated on the basis of energy consumed by customers." Messrs. Baron and Kleha are is wrong. First, the chart and discussion on page 34 of NARUC Manual recognize and include the classification of distribution facilities upstream of meters and services on an energy basis. That classification is contested in this proceeding by PPL, OSBA, PPLICA and the Department of Defense. Second, PPL absolutely considers a customer's kWh usage, and must do so under its tariff, as it determines whether it will incur costs to extend service to a customer or whether guarantees or contributions will be required to protect PPL and its customers from the cost consequences of the extension. Moreover, additional electricity-using devices or more extensive use of existing devices will normally impact both a customer's energy usage and peak demand. A customer's loads cannot be separated from the customer, and it is the loads that drive PPL to incur costs of serving the loads.

Q. AT PAGE 11 OF HIS REBUTTAL TESTIMONY, MR. BARON ARGUES THAT NON-PEAK ENERGY USE CAUSES NO COSTS AND THAT ALL COMMON DISTRIBUTION COSTS SHOULD BE ALLOCATED ON PEAK DEMANDS ONLY. AT PAGE 13 OF HIS REBUTTAL TESTIMONY, MR. KNECHT, TOO, ARGUES THAT USE OF EQUIPMENT OUTSIDE OF THE PEAK PERIOD HAS NO EFFECT ON COSTS AND IS NOT RELEVANT FOR COST CAUSATION. PLEASE COMMENT.

A. I have earlier shown that a customer's sustained energy use is essential to the incurrence of costs by PPL, and without sustained usage PPL would not incur costs to extend its system and provide service. Sustained energy use absolutely bears cost responsibility.[1]

[1] Rejection of this argument would produce an allocated cost result that somehow, miraculously, PPL could provide annual electric energy delivery service, its main product, and incur no costs to provide this service. It could not.

To the extent that the delivery of annual energy requirements is the main reason why PPL exists and costs are incurred, all energy usage during the year bears cost responsibility. Moreover, the Peak and Average cost allocation methodology recognizes that, because average demands are not responsible for all of PPL's distribution facilities investment, *peak demands are responsible for a portion of common distribution costs. The Peak and* Average method allocates fully one-half of such costs on the basis of customer's peak demands. The increased energy usage discussed here by Messrs. Baron and Knecht would not result in an increased allocation of the demand related costs allocated on peak demands under the Peak and Average method.

Q. AT PAGE 12 OF HIS REBUTTAL TESTIMONY, MR. BARON ARGUES THAT NO <u>ADDITIONAL</u> DISTRIBUTION FACILITIES ARE ADDED BECAUSE CUSTOMERS INCREASE THEIR ENERGY USAGE, PARTICULARLY IN OFF-PEAK PERIODS. PLEASE COMMENT.

A. First, to the extent that Mr. Baron fails to limit his argument strictly to off-peak consumption, he is wrong. Energy usage during peak periods will affect peak demands. Second, increased appliance usage would normally not be limited to off-peak periods when that usage results from more extensive usage of existing appliances generally or when that usage results from usage of a customer's increased appliance stock.

Third, Mr. Baron's statement about additional facilities, and hence <u>additional</u> costs, is an argument that is presented in terms of marginal costs. In a marginal cost study, off-peak usage is not responsible for peak related costs. I agree, but note two things. The Peak and Average method does not allocate peak related costs (fully 50 percent of PPL's common distribution facilities and related costs in this case) on the basis of energy. Also, the cost study Mr. Baron prefers and the Peak and Average study are both average, embedded, historical, fully allocated cost of service studies -- not marginal cost studies. If Mr. Baron's off-peak energy argument is based on short-run marginal cost principles, virtually all of PPL's common distribution facilities-related costs are fixed, i.e., non-variable and hence non-marginal. Marginal cost allocations would result in allocating only a small portion of PPL's total costs. Hence, the allocation of short-run marginal costs would not provide the cost analyst or the Commission with enough information to determine class cost responsibility for PPL's total cost of service. If Mr. Baron's off-peak energy argument is based on long-run marginal cost principles, the same results may be obtained, but perhaps with more controversy (and certainly no estimate of long run marginal costs exists in this proceeding). We do know that PPL absolutely will, and is required to, consider both peak and off-peak energy usage in determining whether it will incur costs and extend service to meet additional load.

PPL's currently applicable tariffs do not encourage off-period-only consumption as posited by Mr. Baron. Moreover, there is no pecuniary incentive for a customer to shift energy usage or otherwise increase only off-peak usage if tariffs do not have time-of-day billing features that contain incentives to assure greater energy usage off-peak. Time varying prices could be cost-effective, and PPL's proposed DSM program is planned to investigate this possibility, especially if rate incentives are crafted on the basis of marginal costs. In this proceeding, limited to total cost allocations, the application of limited, unspecified and undetermined marginal cost prescriptions to an average cost study is incomplete, unwarranted and at odds with fully-embedded cost procedures.

Q. AT PAGE 14 OF HIS PRE-FILED REBUTTAL TESTIMONY, MR. BARON TAKES ISSUE WITH YOUR RECOMMENDATION THAT THE COMMISSION CONTINUE TO USE COST STUDIES AS A "GUIDE". PLEASE RESPOND.

A. Cost studies are controversial. In my 30 years of regulatory experience, I have not observed regulatory authorities being limited to finding in favor of the position of one of the litigants to the exclusion of all other views. Rather, Commissions have an affirmative responsibility to set just and reasonable rates. Presumably, Mr. Baron believes that the Commission is required to select one of the two costs of service studies presented in this proceeding, when he testifies at page 74 of his rebuttal testimony:

> One of the Commission's functions is to decide issues related to the assumptions for the cost of service study.

As an economist, I do not read *Lloyd* as requiring the Commission to find that any average, embedded, historic, fully allocated class cost of service study, all of which attempt to allocate primarily fixed costs, so precisely determines cost responsibility that the results must be slavishly converted into rates. If one of the two studies in this case is to be used in guiding the spread of PPL's increased authorized revenues, I recommend use of the Peak and Average cost method, which in my opinion, more reasonably allocates common distribution costs than the customer/demand study performed by PPL.

Q. AT PAGE 7 OF HIS REBUTTAL TESTIMONY, MR. KNECHT CRITICIZES YOUR DESCRIPTION OF PPL'S SERVICE AS THE DELIVERY OF ITS CUSTOMERS' ANNUAL ENERGY REQUIREMENTS AT ALL TIMES DURING THE YEAR AND AT VARYING RATES OF DELIVERY. PLEASE RESPOND.

A. Mr. Knecht does not take issue with my description of PPL providing annual delivery of PPL's customers' annual energy requirements. Mr. Knecht explains that because customers have no way of storing energy, their power demands fluctuate continuously. Yes. This is why I further described PPL's service to include <u>varying rates of delivery</u>. If one were to sum up all the varying customer requirements throughout the year, the sum would equal the customer's annual energy delivery requirement. This is exactly what one would expect. PPL must, and indeed does, provide for the delivery of those annual requirements, at the varying rates of delivery demanded by the customer throughout the year. Mr. Knecht's testimony here reveals no error in my description of PPL's delivery service.

However, Mr. Knecht seems to find fault with my describing a customer's annual requirements as an average hourly demand (by dividing a customer's annual use of electricity by the 8,760 hours in a year), and using the average demand concept to allocate a portion of PPL's common distribution facilities. For cost allocation purposes it doesn't matter if one refers to annual usage or average usage of electricity. I explained in my direct testimony at page 17, footnote 3, that average demands bears the same relationship as annual demands. This means that an allocation on the basis of class annual energy requirements is identical to an allocation on class average demands. Mr. Knecht agrees with this result, as shown in footnote 2 on page 4 of Mr. Knecht's rebuttal testimony. Simply referring to the allocation as an allocation on average demands, at times, rather than any allocation on annual energy, does not invalidate the necessity of sufficient annual electricity requirements in order for PPL to incur the costs related to extending service to new loads.

At page 7 of his rebuttal testimony, Mr. Knecht appears to argue that there should be no variance around a customer's average demand if average demand is going to be used as a cost determinant.

> Moreover, the inability of the customer to store electric energy makes the averaging of demand irrelevant for most costs. If the customer could store energy, he could have PPL deliver it on a constant basis. The customer could put it in his closet when he doesn't need it, and take it out when he does. Under those

conditions, the annual average energy demand would be a cost determinant.

I have explained the importance of annual energy to the existence of costs on PPL's system and to PPL's decisions to incur costs to extend service. Whether one refers to annual energy or to its equivalent, average demand, both of which incorporate all of a customer's varying energy usage every hour of the year, does not alter the conclusion that energy usage causes a portion of PPL's common distribution facilities costs. In my opinion, because of the equivalence of average demands and annual energy when used for cost allocation purposes, either term can be used to describe the basis of the resulting class allocators.

Q. AT PAGE 8 OF HIS REBUTTAL TESTIMONY, MR. KNECHT TESTIFIES THAT YOU IGNORE ALTOGETHER THE ISSUE OF THE LOCATION TO WHICH THE ELECTRICITY IS DELIVERED. PLEASE COMMENT.

A. The essence of my allocation of a portion of PPL's common distribution costs of annual energy (or average demands) is related to the absolute essentialness of sufficient continuing, non-speculative annual requirements to warrant the incurrence of costs by PPL. In short, PPL will incur costs to extend its facilities to acquire new loads. This addresses the requirement to deliver electricity to where the electricity is used. PPL will not incur costs to "connect" customers absent sufficient load requirements.

Q. AT PAGE 8 OF HIS REBUTTAL TESTIMONY, MR. KNECHT ARGUES THAT BECAUSE CAR RENTAL COMPANIES MAY CHARGE A FIXED DAILY RATE FOR A CAR THAT THIS ESTABLISHES THE WISDOM OF CLASSIFYING AND ALLOCATING A PORTION OF PPL'S COMMON DISTRIBUTION FACILITIES ON A CUSTOMER BASIS. IS HE RIGHT?

A. No. First of all, car rental companies do offer rates that impose charges for usage. Second, car rental companies can and do narrow the range of miles driven, thus reducing the variance around the average, by including contractual terms that limit the car's usage, say, to the state in which the car is rented. Third, notice in Mr. Knecht's example, the car can be rented for as short a period as a day.

When a service (car rental) can be purchased or not for very short time periods, its price for all practical purposes is volumetric. For example, if the customer had to pay a fixed fee equal to the car rental company's annual cost (akin to what is at issue in this proceeding -- the allocation of PPL's annual cost of services) but only use it for one or a few days, Mr. Knecht might have a point. However, a car rental customer need only pay a tiny portion of the annual cost of a car if he only rents it for one or a few days. And, a customer would be a fool to incur a cost to rent a car on days when the customer did not contemplate using the car. Moreover, in Mr. Knecht's example, the customer need only incur a cost on the day when he uses the car. Having rented the car once, the customer is not subject to continuing fixed payments to the rental company just because the customer may want to rent a car again sometime in the future. This is another stark contrast between Mr. Knecht's allocation of significant, annual cost responsibility on a continuing basis for payment by the utility customer to be "connected" to the system in case he wants to receive service (i.e., rent the car in Mr. Knecht's example) and because the Company stands ready to provide the service.

Finally, if the car rental company in Mr. Knecht's example, attempted to impose a continuing payable charge (i.e., allocate a significant portion of its annual car costs) to a customer who now has to pay for the car only on days when he needs to use a car, the customer can simply avoid this result by avoiding the example company and renting a car from another competitor. These important differences render Mr. Knecht's car rental example inappropriate and improper for use in discerning and prescribing how a large portion of PPL's common distribution costs should be allocated.

Q. AT PAGE 11 OF HIS REBUTTAL TESTIMONY, MR. KNECHT STATES PROFESSOR BONBRIGHT ADMITS THAT, "IN ACTUAL PRACTICE THE VAST MAJORITY OF UTILITIES USE SOME FORM OF MINIMUM SYSTEM TO CLASSIFY COSTS WHICH IS IN LINE WITH THE FERC ACCOUNTS," AND THAT PROFESSOR BONBRIGHT'S OPINION IS NOT CONSISTENT WITH THE JUDGMENT OF MOST UTILITIES AND REGULATORS. DOES THIS INVALIDATE PROFESSOR BONRIGHT'S CRITICISMS OF THE SO-CALLED CUSTOMER COST NOTION?

A. The significance of the Professor Bonbright statement quoted by Mr. Knecht is that, knowing full-well that the minimum size method has it advocates, Professor Bonbright analyzes the concept, is obviously critical of the concept, and does not believe his criticisms are answered by his observation that the classification of a portion of distribution costs upstream of meters and services has its advocates.

Q. AT PAGE 14 OF HIS REBUTTAL TESTIMONY, MR. KNECHT DISCUSSES A DISTRIBUTION CUSTOMER AT PRIMARY WHO DEMANDS STANDBY SERVICE, WHICH WOULD REQUIRE PPL TO CONSTRUCT FACILITIES CAPABLE OF MEETING THE CUSTOMERS' MAXIMUM DEMAND, BUT PRESUMABLY REQUIRE THE DELIVERY OF LITTLE ENERGY. DOES THIS EXAMPLE IMPEACH THE NOTION OF CLASSIFYING PRIMARY DISTRIBUTION SYSTEM COSTS INTO BOTH DEMAND AND ENERGY COMPONENTS, AS ARGUED BY MR. KNECHT?

A. No. On the contrary, Mr. Knecht's example here shows the necessity of recognizing energy as a determinant of costs, as PPL's tariff requires PPL to do before it will incur costs. Mr. Knecht testifies:

> This customer plans to install a generator at its site which is capable of meeting the customer's load for 90 percent of the hours in the year.... To meet this customer's requirements, PPL would need to construct its distribution system such that it is capable of meeting that customer's maximum demand. That is, PPL will incur costs that are no different than if the customer had no self-generation, since the full capacity needs to be in place as a backstop.

It is not true that, "PPL will incur costs. ..." absent considerations required in its tariff. For example, for a new load to avoid being classified as speculative, there must be no doubt as to the continued use of the new facilities. A speculative extension will require a revenue guarantee or a contribution in aid of construction. The revenue guarantee for speculative extensions equals the estimated fully allocated installation and removal costs, less salvage, with no length allowance. Under these circumstances, PPL and its customers are protected from the consequences of PPL otherwise having to make uneconomic investment decisions. If the customer insists on the extension, PPL will, rather than incurring the costs itself, pass the costs through to the specific customers through the revenue guarantee or required contribution, effectively protecting the Company and its customers from adverse cost consequences. Mr. Knecht's standby service example does not impeach the validity of the classification of primary distribution costs into both energy and demand components.

Q. AT PAGE 15 OF HIS REBUTTAL TESTIMONY, MR. KNECHT USES THE AVERAGE AND EXCESS "STANDARD INDUSTRY ALLOCATION METHODOLOGY" AS A STANDARD AGAINST WHICH TO JUDGE THE PEAK AND AVERAGE METHODOLOGY. WHEN WEIGHED AGAINST THE AVERAGE AND EXCESS METHOD, MR. KNECHT FINDS THE PEAK AND AVERAGE METHOD WANTING. PLEASE RESPOND.

A. The Average and Excess method produces results that are similar or exactly equal to a pure peak only allocation method. The arithmetic calculations under the Average and Excess method produce a result in the method's pure form that is identical to a pure peak only allocation. Thus, the Average and Excess method is a "wolf in sheep's clothing" method -- it recognizes the importance of allocating a substantial amount of costs on energy (the load factor share), but the attendant arithmetic collapses the result right back into a peak demand only method.

Mr. Knecht knows that the Average and Excess method, while professing to allocate a load factor share of costs on an energy basis, really allocates all, or virtually all, costs on peak demands.[2] In the recent and on-going Philadelphia Gas Works case, Docket No. R-00061931, Mr. Knecht addressed the A&E method, debunking the method. Mr. Knecht devoted a full page of his testimony to show the algebraic proof that in its pure form the Average and Excess method produces class allocation that are exactly equal to each class's share of peak demand.[3] I have included Mr. Knecht's testimony debunking the Average and Excess method in my Schedule RAG-1S accompanying this testimony. For Mr. Knecht to now propose that the discredited Average and Excess method be used as the objective standard against which to measure the reasonableness of the Peak and Average method is wholly without merit.

Q. MR. KNECHT, USING THE AVERAGE AND EXCESS METHOD, CRITICIZES THE PEAK AND AVERAGE METHOD FOR COUNTING AVERAGE DEMAND TWICE, BECAUSE THE PEAK COMPONENT OF THE ALLOCATION METHODOLOGY INCLUDES BOTH AVERAGE AND

[2] PPL allocated all of its primary distribution costs on peak demand.

[3] If excess demands are measured as the excess of class non-coincident peak demands over average demands instead of by the excess of class coincident peak demands over average demands, the resulting A&E factors will differ slightly from the pure peak demand only factors.

EXCESS DEMAND. MR. KNECHT FURTHER, AT PAGE 15 OF HIS REBUTTAL TESTIMONY, SUGGESTS THAT A 100 PERCENT LOAD FACTOR CUSTOMER WOULD BE TREATED UNFAIRLY BY INCLUDING HIS PEAK DEMAND, WHICH EQUALS HIS AVERAGE DEMAND, IN THE ALLOCATION OF PEAK DEMAND RELATED COSTS. PLEASE COMMENT.

A. The Peak and Average method utilizes peak demands because all customers requiring service at the time of peak are responsible for peak-related costs. In discussing peak demand related costs, Professor Bonbright agrees that all customers demanding service at time of peak are responsible for peak demand related costs. When discussing the concept of incremental peak-related costs, Professor Bonbright puts it this way:

> In short, prices based on marginal costs should be greater during peak periods. Because an electric company must size its system to meet the peaks, <u>any peak period user is contributing to the peak</u>, regardless of its off peak usage. Thus, <u>all peak users contribute to the peak</u> and all nonpeak usage is irrelevant. [Bonbright, James C., <u>Principles of Public Utility Rates</u>, Public Utilities Reports, Arlington, VA, 1988, p. 475, *emphasis added*]

Under the Average and Excess method, when peak demands are calculated as the excess of peak demands over average demands, a 100 percent load factor customer, who is guaranteed to be demanding service whenever the peak occurs, would bear no responsibility for the costs of meeting the peak (because such a customer would have no excess of peak demand over average demand), thus violating the principle of cost causality.

Q. AT PAGE 16 OF HIS REBUTTAL TESTIMONY, MR. KNECHT MENTIONS THAT PROFESSOR BONBRIGHT OFFERS "QUALIFIED SUPPORT FOR

THE PEAK DEMAND METHOD OF COST CLASSIFICATION FOR CAPACITY-RELATED COSTS." PLEASE RESPOND.

A. Mr. Knecht also mentions here in his testimony that Professor Bonbright goes on to qualify his support by limiting it to only incremental capacity costs. By its own terms, Professor Bonbright supports allocating only a portion of demand related capacity costs, not all demand related costs, on peak demands. In spite of this clear limitation and Mr. Knecht's recognition that the incremental cost approach is not used in Pennsylvania, Mr. Knecht concludes that, "... Professor Bonbright's reasoning generally supports PPL's methodology." This conclusion of Mr. Knecht is also at direct odds of the further statement in the very paragraph of Professor Bonbright's text that Mr. Knecht cites. That next paragraph specifically states that the concept does not apply to the average cost per kilowatt of total capacity that is at issue here:

> But the argument applies only to the allocation of *incremental* capacity cost--to the cost per kilowatt of enhancing the capacity rather than to the average cost per kilowatt of total capacity. [Bonbright, James C., Principles of Public Utility Rates, Public Utilities Reports, Arlington, VA, 1988, p. 504, emphasis in original]

Q. AT PAGE 18 OF HIS REBUTTAL TESTIMONY, MR. KNECHT TAKES ISSUE WITH YOUR ALLOCATION OF SERVICES ON A CUSTOMER BASIS. PLEASE RESPOND.

A. Mr. Knecht mentions that I state that one customer, one Service and one Meter are required. This is an accurate statement by Mr. Knecht, and the statement is true. Mr. Knecht quibbles that I testified that I classified and allocated Services and Meters on a customer basis. Mr. Knecht correctly points out that I allocate Services on a weighted customer basis. I could have been more precise, however it would never occur to me that a cost analyst would allocate services on a raw, unweighted customer basis.

The classification and allocation of Services on a customer basis is a standard procedure. For example, while not dispositive, the NARUC Manual includes a customer classification for Services in the chart shown on page 34. A customer-only classification and allocation, as opposed to the customer/demand allocation results Mr. Knecht apparently prefers, recognizes that Services plant is generally associated with the provision of service to individual customers -- it does not perform a system function. Customer demands are less at the time of class peaks than the sum of individual customer peak demands due to diversity of demand. However, there are no diversity benefits that affect Services costs.

Mr. Knecht would apply different, but undetermined, weights to customers than I did, and he complains that my allocations understate Services costs for larger customers and overstate them for the smallest customers, namely residential and GS-1 customers. However, both residential and GS-1 customers are allocated less cost under the Peak and Average cost study than under the customer/demand study. Since no one is proposing a movement to fully cost-based rates under either study, the impact of any change that would further reallocate costs away from smaller customers who are already benefited under the Peak and Average method, is moot.

Q. AT PAGE 19 OF HIS REBUTTAL TESTIMONY, MR. KNECHT ARGUES THAT IT IS OKAY FOR THE COMMISSION TO CHANGE HOW THE MINIMUM SYSTEM IS DETERMINED, IN CONTRAST TO HIS TESTIMONY ON PAGE 1, WHERE HE TESTIFIES THAT YOUR PROPOSAL IN SUPPORT OF THE PEAK AND AVERAGE METHOD IS NOT REASONABLE BECAUSE, "IT REPRESENTS A RADICAL DEPARTURE FROM LONG-ESTABLISHED COMMISSION PRECEDENT FOR PPL ELECTRIC UTILITIES." PLEASE RESPOND.

A. At pages 6-7 of my surrebuttal testimony, I address Mr. Kleha's advice to the Commission to use PPL's cost of service study to preserve consistency. Mr. Knecht points out, *in its 1995 PPL Order, the Commission affirmatively found in favor of* PPL's previously accepted minimum size system calculation procedures, even though the procedures were challenged as improperly including some capacity costs. In this proceeding, no party challenges PPL's proposed minimum size system calculations, which have been changed to address this improper inclusion of capacity costs. If the Commission were to accept PPL's proposal in this case, the Commission would be modifying its 1995 PPL Order on this issue.

Rate Design

Q. AT PAGE 24 OF HIS REBUTTAL TESTIMONY, LINES 1-9, MR. KASPER ARGUES THAT CUSTOMER COSTS ARE ON THE ORDER OF $24 PER MONTH OR $13.00 PER MONTH WHEN BASED ON FULLY DISTRIBUTED COSTS OR "DIRECT" COSTS, RESPECTIVELY, AND THIS DEMONSTRATES THE CONSERVATIVE NATURE OF PPL'S PROPOSED $10.00 MONTHLY CUSTOMER CHARGES. PLEASE COMMENT.

A. I explained at page 28 of my direct testimony that a more meaningful customer charge would exclude fixed costs. PPL's current residential customer charge of $7.96 and OCA's proposed $8.00 charge already are high enough to include substantial amounts of fixed cost recovery. Residential customers have only two billing elements applied to their electric delivery service requirements -- the customer charge and volumetric charges. Both PPL's customer and volumetric charges include fixed cost recovery, as rates are set to provide PPL with an opportunity to recover its Commission-determined costs of service. PPL's residential charge has increased from its $6.65 level in its 2004 rate case to its $8.00 level as a result of that rate case and is now proposed to increase to its proposed \$10.00 level, a 52.7 percent increase (\$10.00 ÷ \$6.65 = 1.527) since the expiration of PPL's distribution rate cap.

Q. ARE THERE OTHER PROBLEMS WITH SHIFTING COST RESPONSIBILITY TO FIXED CHARGES?

A. Yes. In a report responding to the National Association of Regulatory Utility Commissioners, addressing utility pricing in a post-restructured environment, the Regulatory Assistance Project expressed its concerns with increased reliance on fixed charges this way:

> Fixed, recurring, unavoidable charges also violate certain principles of rate design. They do not necessarily promote economic efficiency, since they tell a consumer little about the costs that his or her consumption imposes on the system. This can lead to uneconomic consumption and degraded system reliability. Nor are fixed charges particularly fair, since consumers contribute equally to the utility's revenues, regardless of the level of their usage. Consequently, lower-volume and, in many cases, off-peak consumers would pay a disproportionate share of the network's costs. Those who make greater use of the network should bear a proportionately greater share of its costs. In addition, shifts from usage-based to fixed charges could have undesirable revenue impacts upon a company, either excessive losses or earnings, that would require perhaps politically unpalatable remedial actions. Revenue stability may be jeopardized, and public faith in the regulatory institutions threatened.
>
> Usage-based rate designs promote economic efficiency, fairness, environmental protection, and the deployment of distributed resources. Fixed charges, because they are unavoidable (except where a customer goes off-grid entirely), discourage cost-effective consumer demand responses and innovation, to which firms would likewise respond. The constant pressure for dynamic efficiency would be lost.
>
> In sum, we urge regulators to adopt pricing and rate setting policies that will serve the longer-term public interests: fairness, economic efficiency, competitive provision and innovation, and environmental protection. In the distribution system, this calls for

> usage-based pricing--primarily volumetric (energy-based) but also, where appropriate, demand-and energy-based. [Charging for Distribution Utility Services: Issues in Rate Design. A Report Prepared for the National Association of Regulatory Utility Commissioners, the Regulatory Assistance Project ("RAP"), December 2000, pp. 7-8]

Also, regulation is supposed to emulate the results that would be obtained if the utility service were provided under competition rather than by a regulated monopolist. The RAP Report puts it this way:

> It has often been said that regulation is meant, among other things, to serve as a proxy for competition, to impose upon a single provider the disciplines of competitive markets. Therefore, when designing rates, it is appropriate for regulators to consider how competitive markets price their goods and recover their costs of production. [Ibid., p. 17, footnote omitted]

Explaining that competitive markets overwhelmingly sell their goods and services on a per unit basis, the RAP Report to NARUC continues:

> How are products actually priced in competitive markets? Groceries, automobiles, fuels, agricultural products, appliances, communications services, entertainment, even electricity — the list is endless — are all priced in ways that reveal something about how competitive markets operate and about consumer preferences.
>
> Commodity markets come closest to meeting the requirements of economic theory's "perfect competition." Sorghum, crude oil, pork bellies, to name just a few, are all-traded in markets where both suppliers and buyers generally lack the power to unilaterally affect price, the product is homogeneous among all suppliers, and quality and price information is instantly available. The commodity is sold on a unit basis, and prospective buyers are not required to make minimum payments, even if they choose to purchase nothing.[11] As for virtually all goods, the production of these commodities invariably involves agricultural, extraction, or other processes that require suppliers to make investments in fixed assets (land, processing equipment, etc.) and to incur ongoing operational expenses (labor, fuel, transportation, etc.).
>
> Most retail sales take place under similar conditions. Grocery stores, department stores, boutiques all place a variety of offerings on their

> shelves. Consumers are free to pick and choose amongst them, according to their needs and wants, and purchase as little or as much as they wish. Included in the costs of their products are a host of costs — the fixed and variable costs of production, delivery, and marketing — which all must be recovered through the sale of the goods. The retailer's own costs too must be covered, but it is rare indeed that it charges potential customers simply to enter the premises. But even if some retailers do impose such fees, they are nevertheless avoidable: customers can simply choose alternative suppliers who do not exact similar charges. [Ibid., pp. 18-19, footnote omitted]

Q. MR. KASPER OBJECTS TO YOUR GREATER RELIANCE ON VOLUMETRIC REVENUES THAN PPL PROPOSES BECAUSE YOUR PROPOSED VOLUMETRIC RATES DO NOT TRACK CHANGES IN DISTRIBUTION COSTS. PLEASE RESPOND.

A. At page 24 of his rebuttal testimony, Mr. Kasper testifies that my proposed "equal, across the board increase to the kWh charges increases the dependence on kWh charges for the Company's Distribution function." Mr. Kasper further testifies on page 24, when discussing usage reductions that, "reduced usage will not reduce the cost to operate the distribution system." Because PPL has substantial fixed costs, its current and PPL's proposed residential volumetric rates and its customer charges are both set above marginal cost. The same is true of the OCA proposed rates. Thus, under PPL's proposed rates it is also true that revenues will not exactly track costs because "reduced usage will not reduce the cost to operate the Distribution system." Moreover, Mr. Kasper's recommendation, to apply lower volumetric rates so as to determine a higher monthly customer charge, would also result in unrecovered costs as customers left the system because fixed costs would not fall commensurate with the loss of customer charge revenues. Mr. Kasper's observation, that changes in PPL costs do not track changes in revenues when PPL's rate elements are priced above marginal costs is a relevant observation for all of PPL's proposed pricing elements as well as being relevant to OCA's proposed residential prices.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	DOCKET NO. R-00072155
PPL ELECTRIC UTILITIES CORPORATION	)	

SCHEDULE ACCOMPANYING THE

SURREBUTTAL TESTIMONY

OF

RICHARD A. GALLIGAN

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

AUGUST 2007

EXETER

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

OSBA STATEMENT NO. 2

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-00061931**
	:	
PHILADELPHIA GAS WORKS	:	

Rebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Retail Gas Supply Competition

Date Served: May 4, 2007

Date Submitted for the Record: ________________________

In its CCOSS, PGW proposes to allocate the demand-related costs in proportion to class design day demand. The logic of this approach is relatively simple -- PGW must size its distribution mains in order to accommodate design day demands, and therefore design day demand is the cost causation factor.

Mr. Kubas proposes to use a variant of the "average & excess" ("A&E") allocation methodology described in AGA's Gas Rate Fundamentals text for the demand component of mains costs. The A&E method is a hybrid allocation methodology, consisting of an "average demand" component and an "excess demand" component. Mr. Kubas proposes a 50/50 weighting of these components.

Mr. Galligan proposes to use a "peak & average" ("P&A") allocation methodology. The P&A method is also a hybrid allocation methodology, consisting of an "average demand" component and a "peak demand" component. Mr. Galligan proposes an 80 percent average, 20 percent peak weighting scheme.

Q. Are the A&E and P&A methods similar?

A. Despite the similarity in names, it is very important to recognize that they are not. In practice, particularly for natural gas utilities, the A&E method will usually produce results that are much closer to the results of a peak demand method (such as that used by PGW) than to the P&A method (such as that used by Mr. Galligan).

Q. Why does the A&E method produce a result that is similar to a peak demand method?

A. Remember that the A&E allocator represents a weighting of an *average* demand component and an *excess* demand component, where excess demand represents peak demand *minus* average demand. Thus, conceptually, the A&E consists of an average component, and a *peak minus average* component. Because the average component is deducted from excess demand, the overall allocator is conceptually similar to a peak methodology.

In fact, in its pure form, and in the absence of any demand diversity, the A&E allocator is identical to a peak demand allocator. The specific formula for the A&E allocator is:

$$A\&E_i = w * A_i/A_t + (1-w) * (P_i - A_i)/(P_t - A_t)$$

where: "w" is the average demand weighting factor, "A" is average demand, "P" is non-coincident peak demand, and "i" and "t" represent a class and the system total.

In the pure form of the A&E method, the weighting factor is set equal to the system load factor. Because, in the absence of any load diversity between rate classes (which is relatively common for NGDCs), rate classes all tend to peak during extreme weather conditions, we can substitute:

$$w = A_t/P_t$$

into the preceding equation. It is relatively easy with a little algebra to simplify the expression to:

$$A\&E_i = A_t/P_t * A_i/A_t + (1 - A_t/P_t) * (P_i - A_i)/(P_t - A_t)$$

$$A\&E_i = A_i/P_t + ((P_t - A_t)/P_t) * (P_i - A_i)/(P_t - A_t)$$

$$A\&E_i = P_i/P_t$$

That is, the A&E allocator for each class is exactly equal to each class's share of peak demand.

Thus, the approach advocated by Mr. Kubas is conceptually much closer to that advanced by PGW than the method presented by Mr. Galligan.[12]

Q. Do you agree with Mr. Kubas regarding the use of the A&E allocator?

A. I agree with Mr. Kubas that the A&E allocator is a reasonable and accepted approach for allocating demand-related mains costs. Conceptually, it is appealing because it recognizes that costs are generally incurred in proportion to a measure of system peak demand. Moreover, in contrast to Mr. Galligan's P&A method, the excess demand

[12] In fact, as shown in his workpapers, when Mr. Kubas calculates the excess demand factor, he assumes that there is not demand diversity (i.e, that there is no difference between class non-coincident peak demand and class coincident peak demand). Thus, had Mr. Kubas used the standard weighting methodology, his A&E demand allocator would be exactly the same as PGW's peak demand allocator.

OCA Hearing Ex 4
Hhg vk
AUG 16 2007

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v.	:	
PPL Electric Utilities Corporation	:	Docket No. R-00072155

DOCUMENT FOLDER

AFFIDAVIT OF RICHARD A. GALLIGAN

I, Richard A. Galligan being duly sworn according to law, depose and say that I am a Principal with Exeter Associates, Inc., hired as a consultant by the Pennsylvania Office of Consumer Advocate and have been authorized to make this affidavit on its behalf and that the facts set forth in my Direct, Supplemental, Rebuttal, and Surrebuttal Testimony at OCA St. No. 3, 1-Supplemental, 1R, and 3S, respectively, are true and correct to the best of my knowledge, information and belief and expect to be able to prove the same at any hearing thereof.

Richard A. Galligan
Richard A. Galligan

DOCKETED
SEP 7 - 2007

Subscribed and sworn before me on this 16 day of Aug, 2007.

Deborah M Adams
Notary Public

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AUG 17 2007
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

My Commission Expires: 2/2011

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

In the Matter of:	)	
	)	
Pennsylvania Public Utility Commission et al.	)	**Docket No. R-00072155**
	)	
vs.	)	
	)	
PPL Electric Utilities Corporation	)	

DOD/FEA Statement No. 1

Direct Testimony

Of Kenneth L. Kincel

AUG 16 2007
Hbg. JK

Addressing Customer Class Cost and Revenue Requirement Allocation And Rate Design

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DOCUMENT FOLDER

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DOCKETED
SEP 7 - 2007

FOR

U.S. DEPARTMENT OF DEFENSE AND ALL FEDERAL EXECUTIVE AGENCIES

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AUG 17 2007
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Date Due: July 6, 2007
Filing Due: July 6, 2007

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

In the Matter of:	)	
	)	
Pennsylvania Public Utility Commission et al.	)	**Docket No. R-00072155**
	)	
vs.	)	
	)	
PPL Electric Utilities Corporation	)	

Direct Testimony of Kenneth L. Kincel

Q. PLEASE STATE YOUR NAME, TITLE AND OCCUPATION.

A. My name is Kenneth L. Kincel. I am President of Decision Analysis Corporation of Virginia, an energy consulting firm located at 8009 Snowpine Way, Suite 100, McLean, Virginia. Decision Analysis Corporation of Virginia was founded in 1980 and performs energy modeling and forecasting, and utility market and rate analysis services for government, industry associations, utility commissions and private energy firms. In this capacity, I am currently providing independent expert witness services to the U.S. Department of Defense in utility rate and restructuring cases at federal and state regulatory commissions.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE

A. Details of my education and experience are described in Exhibit KLK-1 which is attached to my testimony. A listing of my recent submissions and testimony to various government utility regulatory agencies is shown in Exhibit KLK-2.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am presenting testimony on behalf of the consumer interests of the U.S. Department of Defense and all other Federal Executive Agencies, hereinafter collectively referred to as "DOD/FEA." In addition to representing the military establishments under his own purview, the Secretary of Defense is delegated authority by the General Services Administration to also provide representation of the consumer interests of the federal civilian agencies in this proceeding. DOD/FEA is deeply interested and affected by the revenue and rate increases being sought in this proceeding before the Pennsylvania Public Utility Commission ("PPUC" or the "Commission"), because DOD/FEA is a very large consumer of electricity from PPL Electric Utilities Corporation ("PPL" or the "Company").

PPL provides electric services to several major military installations including Carlisle Barracks, Tobyhanna Army Depot, the US Naval Support Activity at Mechanicsburg, the Defense Logistics Agency at New Cumberland and the Scranton Army Ammunition Plant. PPL also provides electricity to civilian federal agencies such as the United States Courthouses in Harrisburg and Scranton, the Veterans Affairs Hospital and a federal penitentiary. Because of the diversity of the electricity applications within these facilities, DOD/FEA is taking electric service off of many of the firm service rate schedules of PPL. Therefore, it is important to DOD/FEA that all customer class rates of PPL are just and reasonable.

Exhibit KLK-3 summarizes 12 months of recent billings from PPL to the largest account of each of the three largest military installations served by the Company, namely, Carlisle Barracks, Tobyhanna Army Depot and the US Naval Support Activity at Mechanicsburg. These three military installations alone account for over \$9.7 million in annual billings for electric service from PPL and consume over 156.7 giga-Watt-hours (gWh) of electricity each year. In addition, the US Navy at Mechanicsburg pays PPL \$918,500 each year for Demand Side Management (DSM) projects.

Carlisle Barracks takes electricity from PPL at 69 kilo-Volts (kV) at its on-post substation, and uses two Government-constructed primary loops for distribution downstream of the substation. The non-coincident peak electricity demand at Carlisle Barracks is slightly over 5 mega-Watts (mW). As a result, the Barracks takes electricity primarily on PPL rate schedule LP-5 rather than LP-6 because LP-6 requires payment for a minimum of 10,000 kW of billing demand each month. On LP-5, the Barracks receives 25.2 gWh of electricity and pays PPL \$1.64 million annually, averaging 6.5 cents per kWh. The Barracks enjoys a reasonably high annual load factor (i.e., the average to peak day ratio of electricity consumption) of 56.6%, which helps keep average unit electricity costs low. Carlisle Barracks also receives much smaller volumes of electricity for the more remote areas located on the base, particularly the golf course and Stanwix housing, which are connected directly to PPL lines and therefore employ PPL rate schedule LP-4.

Tobyhanna Army Depot has a non-coincident peak load of 11.6 mW, but takes electricity off of rate schedule LP-5 for two reasons: (1) in past years its monthly billing demand fell below 10 mW for several months of the year, and (2) the Depot receives Economic Development Initiative Credits of \$463 thousand annually, which are not available to LP-6 customers. Recently, however, because of growth at the Depot, monthly peak demand has stayed over 10 mW for nearly all months of the year. As a result, movement to rate schedule LP-6 may be cost-effective after the EDI credits expire at the end of 2009. Currently, Tobyhanna Army Depot consumes 64.1 gWh each year and accounts for $3.8 million in billings from PPL, averaging a very reasonable 5.9 cents per kWh on Rate LP-5. It enjoys a higher annual load factor than Carlisle Barracks, 63.3% versus 56.6%, which contributes to the lower average cost per kWh. The remainder of the difference can be explained by the EDI credits that Tobyhanna Army Depot is receiving.

The US Naval Support Activity at Mechanicsburg is the largest military customer of PPL. It has a non-coincident peak load of 12.6 mW and never drops below 10 mW in monthly billing demand. As a result, it takes electricity off of PPL rate schedule LP-6. It consumes 66.9 gWh and pays $4.3 million each year to PPL for electricity, averaging 6.45 cents per kWh. The Naval Base has a higher annual load factor than Carlisle Barracks, 60.6% versus 56.6%, and therefore as expected, pays a slightly lower average unit cost of electricity, 6.45 cents per kWh versus 6.50 cents per kWh for the Barracks. This Naval Base takes advantage of PPL's Demand Side Management Program (DSM), as stated earlier, and now has two ongoing projects, requiring $918,500 annually in payments to PPL. It also takes very small volumes of electricity delivered to remote areas of the base off of PPL rate schedule LP-4.

Company Witness Oliver G. Kasper, as set forth in Appendix A of his Direct Testimony, proposes to reduce the 2007 base rate revenue requirements for LP-5 customers by $135 thousand (7.37% of class distribution revenues). He further proposes a slight reduction of $5 thousand (3.2%) in 2007 base rate revenue requirements for LP-6 customers. These dollar reductions in revenue requirements were computed and proposed by PPL prior to any knowledge of the Joint Settlement Agreement resulting from the Remand Proceeding under Docket No. 00049255 (hereinafter referred to as the "Remand Settlement Agreement"), which is now before the Commission for consideration. PPL Witness Joseph M. Kleha, in Statement No. 6A, indicated that the Company was not revising its class revenue requirement allocations at this time as a result of the Remand Settlement Agreement, but may choose to do so in its rebuttal testimony later in this proceeding. Thus, there remains the possibility of rate increases on LP-5 and LP-6 resulting from this proceeding. In addition, as shown in Exhibits KLK-4 and KLK-5, PPL is proposing rate changes for other firm requirements rate schedules on which DOD takes service both at military installations and other civilian federal facilities. Thus, it is vitally important to DOD/FEA that the rates resulting from this proceeding be just and reasonable by being adequately based on accurate measurements of class cost of service, and by being free of egregiously high embedded class cross subsidies.

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

A. The purpose of my testimony is to address under this docket, on behalf of DOD/FEA, distribution customer class cost allocation, revenue requirement allocation and rate design issues associated with new rates to be placed into effect on January 1, 2008. In the process of addressing these issues, I provide rebuttal for some of the Company's positions on these issues as presented within their Application.

Regarding cost allocation, I generally support the distribution cost of service study performed by the Company. However, I call for a significant change in the Company's customer class allocation of necessary increases in total revenue requirements. The Company's class revenue requirement allocation does not adequately redress significant cross subsidies among distribution customer classes that are presently occurring and will continue to occur, albeit to a lesser degree, even with the Commission's acceptance of the Remand Settlement Agreement. I propose a class revenue requirement methodology that can be applied whether or not the Remand Settlement Agreement is approved by the Commission, and which will limit all customer classes to paying no more than 125% of the system average return within base rates. This methodology is the same that I proposed in the last PPL rate case (Docket No. R-0004925), but with movement of the maximum allowable class return down from 150% to 125% of the system average return. Thus, I regard this testimony as the second step of a three step program which will be fully implemented over three rate cases (including the next one) that will bring nearly all customer classes to system return parity within base rates.

Regarding rate design, I do not oppose the Company's requested change to make the distribution charge a fixed customer charge for LP-5 and LP-6 customers, because distribution charges to the three military reservations on these two rate schedules are a very small percentage of total electric billings.

Q. WHY DO YOU GENERALLY SUPPORT THE DISTRIBUTION COST OF SERVICE METHODOLOGY EMPLOYED BY THE COMPANY?

A. The Company uses the class maximum demand method, which is based on the highest annual non-coincident peak (NCP) demand imposed by each rate class on its distribution system, to allocate its demand-related distribution costs. Distribution facilities are separated between primary and secondary voltages, and secondary investment is further classified as customer-related and demand-related using the "minimum size system" method. Costs considered customer-related are then allocated on the basis of the numbers of customers in each class.

Within its rate case application, as required, the Company presents a comparison cost of service study based on the "average and excess" allocation method. Under the "average and excess" allocation method demand-related distribution costs are allocated based on average demand (i.e., energy consumption) and the "excess" over average demand (i.e., peak demand minus average demand). This method essentially allocates a greater portion of demand-related costs to customer groups with higher load factors.

I believe that the best cost of service methodology is the one that most closely matches cost allocation with cost causation. The NARUC Electric Utility Cost Allocation Manual (January 1992, p. 12) clearly states this "cost principle," that is, that the cost allocation study should "attribute costs to different categories of customers based on how those customers cause costs to be incurred." Cost causation is best illustrated by the utility's planning process for adding new capacity. The NARUC Manual (p. 96-97) clearly describes the utility's planning process for new distribution capacity as follows:

> There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation. Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.

Thus, in a distribution utility, the most significant factor influencing the Company's expansion plan is the level of peak demand projected for the system. The use of NCP demands as a basis for allocating demand-related distribution plant, like the Company used in its proposed cost-of-service study, is consistent with this principle. In contrast, the "average and excess" allocation method, like any other which allocates distribution facility costs partly based on energy use, fails to adequately satisfy the cost causation principle as specified by NARUC, and should not be considered by the Commission.

The average and excess methodology rests on the assumption that while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs. This is not the case with distribution plant. The provision of continuous service, that is, more throughput at a given peak demand level, does not cause a need for additional capacity. The sole determination of the need for additional distribution capacity is greater peak load requirements on the system. Thus, to burden higher load factor customers with higher costs of distribution plant is grossly inequitable. So, in my view, there is no uncertainty as to which is the more correct cost-of-service methodology to apply – it is the Company's NCP demand-based methodology.

I also support the Company's proposal to use the minimum-size system method for determining the demand and customer components of secondary distribution facilities. The minimum-size system method requires less data to employ and is easier to understand and apply. It is also less prone than the alternative method, the minimum-intercept method, to produce anomalies caused by statistically unreliable results.

In this proceeding, PPL modified its methodology by separating out the demand-related component of the "minimum size system" from the customer-related component. This is discussed by Company Witness Joseph M. Kleha on page 20-21 of his Direct Testimony.

The effect of this modification is to convert some of the minimum system costs to demand-based from customer-based classification, when compared to the methodology used in the last PPL rate case (Docket No. R-00049255). The result of this modification is to shift certain distribution costs from the smaller customer classes (where there are many customers) to the larger customer classes (where there are fewer customers). I do not oppose this modification because I believe the methodology is essentially sound (as presented in Exhibit JMK3) and because it more accurately classifies the costs of the minimum system.

However, I would not have recommended that this methodology change occur during this rate proceeding, because this rate case represents the second step of a three-step program to bring all distribution customer classes to, or very near, the system average return. This cost-of-service methodology modification essentially shifts the "polestar" that the three-step program is using as a target basis for allocating revenue requirements. The result may be a rate increase for certain customer classes (e.g., LP-6 customers if the Remand Settlement Agreement is approved by the Commission) in this proceeding followed by rate decrease in the last rate case, which may be difficult to explain to a customer that is not following the details of these rate cases.

Q. WHY DO YOU OBJECT TO THE COMPANY'S PROPOSAL FOR THE ALLOCATION OF INCREASED REVENUE REQUIREMENTS BY CUSTOMER CLASS?

A. Within its application (Direct Testimony of Company Witness Douglass A. Krall, page 35), the Company proposes two criteria for allocating increased revenue requirements: (1) that the relative rate of return for each customer class moves closer (about half-way on a percentage basis for most rate classes) to 1.0, which is parity with the system average rate of return; and (2) that no customer class be burdened with an increase greater than twice the system average increase. These criteria are intended to implement two principles, namely cost-of-service and "gradualism." These criteria sound reasonable until individual customer class results are scrutinized.

As shown in Exhibit KLK-4, column 4, enormous customer class subsidies have continued to exist subsequent to the original 2004 rate proceeding (based on the Compliance Filing as adjusted for Hurricane Isabel expense). For example, the Company is earning 3.4 times its average system return from customers taking service under LP-5 and 2.9 times the system average return from customers taking service under LP-6. Meanwhile, the Company is earning only 59% of its system average return from residential customers.

Under the Company's revenue allocation proposal in this proceeding, in the event that the Remand Settlement Agreement is <u>rejected</u> by the Commission, the residential customer will be paying only 82% of the system average return within its rates (see column 7 of Exhibit KLK-4). In contrast, the LP-5 customers will still be required to pay about 2.2 times the system average return and the LP-6 customer about 2.0 times the system average return. <u>The Company simply does not go far enough in redressing the egregious gross inequities that presently exist in distribution rates.</u>

The Remand Settlement Agreement goes a long way toward resolving many of these gross inequities, but, in my judgment, more needs to be done. As shown in Exhibit KLK-5, column 7, the Remand Settlement Agreement, when combined with the Company's filed revenue requirement allocation proposal in this proceeding, results in the complete elimination of subsidies from the LP-5 and LP-6 customers to smaller customer classes. However, other large customer classes, such as the IST and ISP classes will still be required to pay <u>more than double</u> the system average rate of return. Moreover, the residential customer class will only be required to pay 87% of the system average rate of return in its rates.

The Company can continue to operate only if it receives an adequate system return from all its customers combined. Thus, if some customer groups are allowed to pay less than their share of total cost of service (including return), then other customer groups must pay more. This is what is occurring now, and will continue to occur even under the Remand Settlement Agreement. This is not only patently unfair, but it leads to inefficiencies. Customers paying less than their cost of service will value electricity delivered by PPL at the price they are paying for it, not the higher cost of delivering it to them. Thus, they will tend to limit their use of conservation measures and undervalue end-use equipment technology that is more efficient in electricity use, as compared to the behavior they would employ if they were receiving the proper pricing signals for electricity. Meanwhile, customers paying more than the cost of service of delivering electricity to them will tend to overvalue the commodity and to substitute other fuels when in fact it would be cheaper to use electricity. Both customer groups are reducing the general welfare of the society.

Optimal efficiency occurs when each customer class is paying the average system return to the Company in its rates. However, the present class cross subsidies currently are so large, and involve so many rate schedules (even if the Remand Settlement Agreement is approved), that a one-step movement during this proceeding to the system average return for all customer classes would lead to sudden and huge impacts on several customer classes, particularly the residential, residential thermal storage and lighting classes, leading to "rate shock." This calls for "gradualism," the principle whereby several steps are taken to approach unitized class returns.

The Company is proposing in this proceeding to implement "gradualism" by having each customer class move only about half-way to the system average return. It proposes to protect again "rate shock" by limiting the rate increase for any one customer class to a maximum of double the system average increase. I believe my proposed revenue allocation methodology is superior to the Company's because it also implements "gradualism" and protects against customer "rate shock", but additionally it directly eliminates all egregious customer class cross subsidies that are embedded in distribution rates.

Q. PLEASE DESCRIBE YOUR PROPOSED CLASS REVENUE REQUIREMENT ALLOCATION METHODOLOGY.

A. My proposed methodology is the same that I advanced during the last PPL rate case (including the Remand Proceeding), but with movement of the maximum allowed class rate of return down from 150% to 125% of the system average return. My proposed revenue allocation methodology is based on several premises, as follows:

- A "just and reasonable" <u>**set**</u> of rates has no single rate class paying more than a defined multiple of the system average percentage return. In this case, I propose that the acceptable maximum class return be set at 125% of the system average return (i.e., a maximum class relative rate of return, or "RROR" of 1.25). This *constitutes a reduction from the 150% maximum class return that I proposed in* the last PPL rate case.

- Rate shock can be defined as a specific maximum allowed percent class revenue increase. In this case, I propose that rate shock be assumed to occur if a class rate increase exceeds 40% if the Remand Settlement Agreement is rejected by the Commission, and double the initial PPL proposed system average increase (i.e., 26%) if the Remand Settlement Agreement is adopted. A lower threshold for rate shock given adoption of the Remand Settlement Agreement is justified because the Agreement itself implements rate increases for many customer classes. The 26% class increase ceiling is the same as that proposed by the Company in this proceeding.
- A "fair" class allocation of any total revenue increase requires customer classes now paying less than the system average percentage return to incur a greater-than-average revenue increase; while customer classes now paying more than the system average percentage return should be granted a less-than-average percentage revenue increase. My methodology will accomplish this result automatically.
- Gradualism can be implemented over several rate cases by reducing the acceptable maximum class return multiple. In this instance, I recommend that during the subsequent general rate case for PPL, all rate classes (except perhaps the RTS and SL/AL classes which have very low RROR's even after this rate increase) be brought to parity with the system average return.

The results of applying this revenue requirement allocation methodology are shown in Exhibits KLK-4 and KLK-5, columns 9 through 13, depending on whether or not the

Commission rejects or adopts the Remand Settlement Agreement, respectively. The steps used to create these columns within these two exhibits are as follows:

1. Set all the classes with present RROR's over 1.25 to an RROR equal to 1.25, and then derive the rate increase (or rate reduction) that is needed.
2. Leave the rate increase for class ISA at the PPL proposed level, since the rates for this class are set by contract agreement and are not affected by this revenue requirement allocation methodology.
3. For any rate class with a present RROR between 1.0 and 1.25, assign a rate increase that will bring the class to an RROR equal to 1.0, provided that such a rate increase will not exceed the system average rate increase. If the system average rate increase is exceeded, set the class rate increase to the system average rate increase and then derive the class return, rate of return and RROR.
4. Derive the rate increase for all remaining classes with present RROR's under 1.0 such that their class RROR's are <u>equivalent</u>. Check to ensure that the maximum allowable rate increase (40% in Exhibit KLK-4 and 26% in Exhibit KLK-5) is not exceeded by any of these rate classes. If so, set the class rate increase to the maximum allowable class rate increase and derive the class return, rate of return and RROR for that class.

As shown in Exhibit KLK-4, in the absence of the Remand Settlement Agreement, both the RTS and SL/AL classes receive the maximum 40% increase in class revenue requirement. The L5-S (Standby) class, which has a present RROR of 1.04 is given a rate increase of 10.3%, which is below the system average percentage increase and is just sufficient to bring this class to parity with the proposed system average percentage return. Rate increases (or decreases) are calculated to bring each class presently paying a RROR more than 1.25 down to 1.25. Many of the customer classes now paying significant cross subsidies, such as the LP-5 and LP-6 classes, will receive reductions in revenue requirements. Then, the required return and corresponding rate increase for the residential class is calculated as that sufficient to bring the total system return to the proposed percentage return. The residential class is given a 27.3% revenue increase, which will bring this class to paying 95% of the system average percentage return within its rates. All egregious cross-subsidies have been eliminated because no customer class is forced to pay the Company more than 125% of the system average percentage return.

If the Remand Settlement Agreement is adopted, the corresponding class revenue increase results are somewhat different, as shown in Exhibit KLK-5. Because the present revenue requirements have been adjusted by the Settlement Agreement, and because the maximum allowed percentage revenue increase is reduced to double the original system average percentage rate increase (26%), four classes are limited to the maximum percentage rate increase, namely, RTS, LP-6, SL/AL and L5-S. The GH class is given a revenue increase of only 5.1%, which is just sufficient to bring its class return to parity with the system average return. The residential class is given a 24.6% rate increase, which brings its RROR to 96% of the system average rate of return within its rates. Again, all egregious cross-subsidies have been eliminated because no customer class is forced to pay the Company more than 125% of the system average percentage return.

Q. HOW WOULD YOUR PROPOSED REVENUE REQUIREMENT CLASS ALLOCATION METHODOLOGY BE IMPLEMENTED IF THERE IS A SCALE-BACK OF PPL'S PROPOSED RATE INCREASE IN THIS PROCEEDING?

A. My class allocation methodology would be implemented using the exact same steps that I have described above given any level for the final allowed total revenue requirement increase. I have prepared Exhibits KLK-6 and KLK-7 to demonstrate how my class allocation methodology would be implemented if PPL's originally proposed 13% overall distribution rate increase is scaled back in this proceeding by 65% to $54.3 million or 8.5%. The maximum allowable class rate increases are held constant at 40% if the Remand Settlement Agreement is rejected (Exhibit KLK-6) and 26% if it is adopted (Exhibit KLK-7). The class threshold for "Rate Shock" is not dependent on the overall system percentage increase, but is more related to what the Commission feels any single rate class can tolerate without a public outcry. Note from these exhibits that most of the reduction in revenue requirements is allocated to the residential class as the total revenue requirement increase is scaled-back.

Q. REGARDING RATE DESIGN, WHY DO YOU NOT OPPOSE PPL'S PROPOSAL TO CONVERT DISTRIBUTION CHARGES TO FIXED CUSTOMER CHARGES FOR THE LP-5 AND LP-6 RATE CLASSES?

A. DOD/FEA is subject to Federal Government regulations that require all conservation and energy investments be justified through use of a life cycle cost analysis. These analyses typically compare the original investment with the present value of the annual stream of energy cost savings derived from the project. Fixed, non-volumetric utility rates, like monthly customer charges, result in no savings from any reduction in demand or consumption resulting from an energy conservation or energy efficiency project. Thus, I am usually opposed to the use of fixed rates when volumetric charges can be applied because the use of fixed rates frustrates the justification of such projects. However, I do agree with the Company that costs that do not vary with volume should be placed in fixed charges. Unfortunately, the Company provided no data indicating that variable O&M expense constitutes only a small percentage of its total distribution costs.

In fact, the distribution charges to the three military installations on these two rate schedules are very, very small as a percentage of the total electric bill (much less than 1%). This occurs because these military installations use essentially none of PPL's distribution facilities. The Government constructed its own distribution facilities on these military reservations and takes service only at transmission voltage from PPL. Thus, because of the very small size of distribution charges to these three military reservations, I do not oppose conversion of the demand-based distribution rates on rate schedules LP-5 and LP-6 to fixed monthly customer charges. I also agree with the Company that the fixed monthly customer charge for distribution on these two rate schedules should ultimately become equal because there is no significant difference in the use of PPL's distribution facilities or the level of customer services required when serving customers on either of these two rate schedules.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes it does.

Commonwealth of Virginia

County of Nelson

Before me, the undersigned Notary Public, personally appeared Kenneth L. Kincel, who being duly sworn on oath deposes and says that the foregoing prepared direct testimony, related exhibits and statement of facts contained therein are true and correct to the best of his knowledge, information and belief.

Kenneth L. Kincel

Kenneth L. Kincel

President, Decision Analysis Corporation of Virginia

Subscribed to and sworn before me on this third day of ~~May~~ July 2007.

Notary Public

My Commission Expires: 8/31/07

Exhibit KLK-1

Education and Qualifications of Kenneth L. Kincel

PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

My name is Kenneth L. Kincel. My business mailing address is Decision Analysis Corporation of Virginia, 8009 Snowpine Way, Suite 100, McLean, Virginia 22102.

WHAT IS YOUR OCCUPATION?

I am an energy consultant in the field of energy modeling, forecasting and economic analysis, and I perform these services as President and Chief Executive Officer of Decision Analysis Corporation of Virginia, an energy and environmental analysis consulting firm.

PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

I was awarded a Bachelor of Science Degree in Engineering by Rensselaer Polytechnic Institute (RPI) in 1967, and a Master of Science in Business Management in 1968, also from RPI. Subsequently, I served as Project Manager at Computer Sciences Corporation where I performed management consulting services until the summer of 1972. From July 1972 through June 1974, I served in several capacities performing industry economic analysis for the Cost of Living Council of the Federal Government during the period of wage and price controls. Following the oil embargo of 1973 -1974, I joined the Federal Energy Administration in the capacity of Director, Office of Energy Demand Policy and Special Projects, and was later promoted to Director, Office of Conservation and Resource Development Policy.

During this period, I testified in several natural gas import cases before the Federal Energy Regulatory Commission as to the economic benefits to the nation of limiting liquefied natural gas imports. I also appeared before several committees of the U.S. Senate and the U.S. House of Representatives on issues such as the availability of winter fuels, the domestic supply and price of natural gas and horizontal oil company divestiture. I headed the Interagency Natural Gas Emergency Task Force, the Synthetic Natural Gas Task Force and the Interagency Liquefied Natural Gas Task Force for the Federal Energy Administration. When the Department of Energy (DOE) was formed in 1977, I joined the Energy Information Administration of DOE, and ultimately became the Deputy Assistant Administrator for Energy Applied Analysis (Modeling and Forecasting). In this capacity, I managed over 200 professional economists, energy analysts and computer scientists in the conduct of energy modeling and forecasting services to produce the *Short Term Energy Outlook, the Annual Energy Outlook* and the *International Energy Outlook,* the major energy forecasting publications of the Federal Government.

In August 1980 I left the Federal Government and founded Decision Analysis Corporation of Virginia (DAC). DAC performs energy and environmental modeling, forecasting and analysis services for utilities, industry associations, utility commissions, private firms and several agencies of the Federal Government, including DOD, Commerce and Energy. Since 1980, DAC has performed over 600 projects involving analysis of energy issues, and I have served as Project Manager for most of these projects.

Since 1994 and to the present, DAC has assisted DOE in the development of the National Energy Modeling System. Since the mid-1980's and to the present, DAC has also provided energy analysis and expert witness services to DOD on utility rate cases and cases involving the restructuring of the natural gas or electric utility industry for competition. I, myself, have testified on cost of capital, revenue requirements, deregulation/industry restructuring policy and/or rate design issues before the Georgia Public Service Commission (natural gas and electricity), the New York State Public Service Commission (electricity), the Federal Energy Regulatory Commission (natural gas), the Kentucky Public Service Commission (electricity), the Public Utility Commission of Texas (electricity), the North Carolina Utilities Commission (natural gas), the New Jersey Office of Administrative Law (electricity) and the Public Service Commission of Maryland (gas and electricity), as listed in Exhibit KLK-2. I have submitted testimony in the last PPL general rate case before the Pennsylvania Public Utility Commission under Docket No. R-00049255 within both the initial 2004 proceeding and the Remand Proceeding which is ongoing at this time.

Exhibit KLK-2
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Direct Testimony of K. L. Kincel for DOD/FEA
July 6, 2007

Recent Testimony and Regulatory Submissions of Kenneth L. Kincel

Regulatory Commission	Date	On Behalf Of	Submission Type	Docket No.	Utility	Issues	Topics Covered
Georgia Public Service Commission	October 18, 1996	US Dept. of Defense/FEA	Direct Testimony	6691-U	United Cities Gas Company	Natural gas rate increase	Revenue requirements, ROE
Federal Energy Regulatory Commission	December 13, 1996	US Dept. of Defense/FEA	Direct Testimony	RP96-190-00	Colorado Interstate Gas Co.	Interstate gas transportation rates	Cost allocation, rate design
New York Public Service Commission	January 7, 1997	US Dept. of Defense/FEA	Direct Testimony	96-E-0134	Niagara Mohawk Power Co.	Electric rate increase	Revenue requirements
Georgia Public Service Commission	October 23, 1997	US Dept. of Defense/FEA	Direct Testimony	8044-U	GPSC NOPR	Implementation of gas retail dereg.	Comments on marketers' certification
Georgia Public Service Commission	October 23, 1997	US Dept. of Defense/FEA	Direct Testimony	8053-U	GPSC NOPR	Implementation of gas retail dereg.	Comments on random assignment of customers
Georgia Public Service Commission	January 23, 1998	US Dept. of Defense/FEA	Formal Comments	8346-U	GPSC NOPR	Implementation of gas retail dereg.	Formal recommendations on unbundling methods
Maryland Public Service Commission	February 12, 1998	US Dept. of Defense/FEA	Direct Testimony	8780	Baltimore Gas & Electric Co.	Gas base rate increase	ROE, rate design
Georgia Public Service Commission	March 31, 1998	US Dept. of Defense/FEA	Direct Testimony	8390-U	Atlanta Gas Light Co.	Unbundling, Restructuring	ROE, rate design, performance rates
Georgia Public Service Commission	October 1, 1998	US Dept. of Defense/FEA	Direct Testimony	9355-U	Georgia Power Company	Base rate increase, earnings sharing	ROE, earnings sharing mechanism
Maryland Public Service Commission	December 18, 1998	US Dept. of Defense/FEA	Direct Testimony	8794	Baltimore Gas & Electric Co.	Electric restructuring	Stranded costs, cost unbundling, rate design
Maryland Public Service Commission	February 3, 1999	US Dept. of Defense/FEA	Direct Testimony	8804	Baltimore Gas & Electric Co.	Electric base rates, rate design	ROE, rate design
Kentucky Public Service Commission	March 18, 1999	US Army	Direct Testimony	98-474	Kentucky Utilities	Electric performance based rates	Performance based rates, earnings sharing mechanism
Kentucky Public Service Commission	March 18, 1999	US Army	Direct Testimony	98-426	Louisville Gas & Electric Co.	Electric performance based rates	Performance based rates, earnings sharing mechanism
Texas Public Utility Commission	September 15, 2000	US Army	Affidavit	23040	TXU Electric Company	Wholesale electric purchaser status	Information in support of petition for Fort Hood
Texas Public Utility Commission	February 2, 2001	US Army	Direct Testimony	22350	TXU Electric Company	Unbundling, Restructuring	Rate design
Georgia Public Service Commission	October 12, 2001	US Dept. of Defense/FEA	Direct Testimony	14000-U	Georgia Power Company	Base rate increase, earnings sharing	ROE, earnings sharing mechanism
North Carolina Utilities Commission	August 23, 2002	US Dept. of Defense/FEA	Direct Testimony	G21 Sub 431	North Carolina Natural Gas Corp.	Base rate rebalancing and increase	Rate design
New Jersey Office of Administrative Law	December 20, 2002	US Dept. of Defense/FEA	Direct Testimony	ER02080506-7 PUC7983,4-02	Jersey Central Power & Light Co.	Base rate increase, surcharges	ROE, ROI, rate design
Kansas State Corporation Commission	July 10, 2003	US Dept. of Defense/FEA	Direct Testimony	03-KGSG-602-RTS	Kansas Gas Division, ONEOK, Inc.	NG base rate increase, rate design	ROE, rate design
North Carolina Utilities Commission	August 12, 2003	US Dept. of Defense/FEA	Direct Testimony	G21 Sub 442	North Carolina Natural Gas Corp.	NG base rate increase, rate design	ROE, rev. reqts,.rate design, terms
Kentucky Public Service Commission	March 19, 2004	US Dept. of Defense/FEA	Direct Testimony	2003-00433	Louisville Gas & Electric Company	NG and electric base rate increases	ROE, cost allocation, rate design, terms and conditions
Pennsylvania Public Utility Commission	June 28, 2004	US Dept. of Defense/FEA	Direct Testimony	R-00049255	PPL Electric Utilities Corporation	Electric base rate increases	ROE, cost allocation, rate design, terms and conditions
Georgia Public Service Commission	October 6, 2004	US Dept. of Defense/FEA	Direct Testimony	18300-U	Georgia Power Company	Electric base rate increases	ROE, cost allocation, rate design, terms and conditions
North Carolina Utilities Commission	August 26, 2005	US Dept. of Defense/FEA	Direct Testimony	G-9 Sub 499; G-21 Sub 461; G-44 Sub 15	Piedmont NG Company/NCNG	NG base rate increase, rate integration	ROE, rev. reqts,.rate design, terms & conditions
Wisconsin Public Service Commission	October 12, 2005	US Dept. of Defense/FEA	Direct Testimony	4220-UR-114	Excel Energy/Northern States Power	Electricity and NG base rate increases	ROE, rev. reqts., cost allocation, rate design
New York Public Service Commission	December 19, 2005	US Dept. of Defense/FEA	Direct Testimony	05-G-0935 and 05-E-0934	Central Hudson Gas & Electric Co.	NG Base Rate Increase and Gas Balancing	Cost of service, cost allocation, rate design
Kansas State Corporation Commission	September 27, 2006	US Dept. of Defense/FEA	Direct Testimony	06-KGSG-1209-RTS	Kansas Gas Division, ONEOK, Inc.	NG Bsae Rate Increase	ROE, cost allocation, rate design
Pennsylvania Public Utility Commission	May 11, 2007	US Dept. of Defense/FEA	Direct Testimony	R-00049255 REMAND	PPL Electric Utilities Corporation	Remand Base Rates - PA Court Decision	Cost Allocation and Rate Design

Exhibit KLK-3 Schedule 1
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Direct Testimony of K. L. Kincel for DOD/FEA
July 6, 2007

Carlisle Barracks Calendar Year 2006 Billings from PPL

PPL Rate Schedule LP-5

Cost Item/Month of Meter Reading	Jan '06	Feb '06	Mar '-6	Apr '06	May '06	June '06	July '06	Aug '06	Sept '06	Oct '06	Nov '06	Dec '06	Total
Electricity Consumed (kWh)	2,213,000	1,874,000	2,000,000	1,975,000	2,065,000	2,175,800	2,186,919	2,653,000	2,281,800	1,860,200	1,969,800	1,955,800	25,210,119
Demand (kW)	3,732	3,547	3,525	3,594	3,646	4,575	4,000	5,089	4,380	3,838	3,396	3,460	46,782
kWh Used													
Billing kW	3,732	3,547	3,525	3,594	3,646	4,575	4,000	5,089	4,380	3,838	3,396	3,460	46,782
First 200 kWh per kilowat of the Billing kW	746,400	709,400	705,000	718,800	729,200	915,000	800,000	1,017,800	876,000	767,600	679,200	692,000	9,356,400
Next 200 kWh per kilowat of the Billing kW	746,400	709,400	705,000	718,800	729,200	915,000	800,000	1,017,800	876,000	767,600	679,200	692,000	9,356,400
Additional kWh	720,200	455,200	590,000	537,400	606,600	345,600	586,919	617,400	529,800	325,000	611,200	571,800	6,497,319
Distribution Charges													
Distribution Charge Rate (cents/kW)	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	
Distribution Charge ($)	1,191	1,131	1,125	1,147	1,163	1,459	1,276	1,623	1,397	1,224	1,083	1,104	14,923
Transmission Charges													
Transmission Charge (cents/kWh)	0.583878	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	
Transmission Charge ($)	12,921	11,338	12,100	11,949	12,493	13,164	13,231	16,051	13,805	11,254	11,916	11,833	152,054
Competitive Transition Charge (CTC)													
CTC Demand Charge Rate ($/kW)	0.30448481	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	
CTC Demand Charge ($)	1,136	1,082	1,075	1,096	1,112	1,395	1,220	1,552	1,336	1,171	1,036	1,055	14,267
1st Block CTC Energy Rate (cents/kWh)	0.278272	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	
1st Block CTC Energy Charge ($)	2,077	2,029	2,016	2,056	2,086	2,617	2,288	2,911	2,505	2,195	1,943	1,979	26,702
2nd Block CTC Energy Charge Rate (cents/kWh)	0.237818	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	
2nd Block CTC Energy Charge ($)	1,775	1,731	1,720	1,754	1,779	2,233	1,952	2,483	2,137	1,873	1,657	1,688	22,783
3rd Block CTC Energy Charge Rate (cents/kWh)	0.206332	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	
3rd Block CTC Energy Charge ($)	1,486	965	1,251	1,139	1,286	733	1,244	1,309	1,123	689	1,296	1,212	13,733
Total CTC Charges ($)	6,474	5,807	6,062	6,045	6,263	6,978	6,704	8,255	7,102	5,928	5,931	5,935	77,485
Intangible Transition Charge (ITC)													
ITC Demand Charge Rate ($/kW)	0.93190899	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	
ITC Demand Charge ($)	3,478	3,196	3,176	3,238	3,285	4,122	3,604	4,585	3,946	3,458	3,060	3,117	42,266
1st Block ITC Energy Rate (cents/kWh)	0.850105	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	
1st Block ITC Energy Charge ($)	6,345	5,994	5,957	6,074	6,162	7,732	6,760	8,600	7,402	6,486	5,739	5,847	79,100
2nd Block ITC Energy Charge Rate (cents/kWh)	0.724120	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	
2nd Block ITC Energy Charge ($)	5,405	5,108	5,076	5,175	5,250	6,588	5,760	7,328	6,307	5,527	4,890	4,982	67,397
3rd Block ITC Energy Charge Rate (cents/kWh)	0.630121	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	
3rd Block ITC Energy Charge ($)	4,538	2,850	3,693	3,364	3,797	2,165	3,674	3,865	3,317	2,035	3,826	3,579	40,703
Total ITC Charges ($)	19,766	17,148	17,903	17,852	18,494	20,607	19,798	24,379	20,972	17,505	17,515	17,527	229,465
Generation Charge (Capacity and Energy)													
Generation Capacity Charge Rate ($/kW)	4.65751466	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	
Generation Capacity Charge ($)	17,382	17,182	17,075	17,409	17,661	22,161	19,376	24,651	21,217	18,591	16,450	16,760	225,916
1st Block Gen. Energy Rate (cents/kWh)	4.16405900	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	
1st Block Gen. Energy Charge ($)	31,081	30,490	30,301	30,894	31,341	39,327	34,384	43,745	37,650	32,991	29,192	29,742	401,138
2nd Block Gen. Energy Charge Rate (cents/kWh)	3.503695	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	
2nd Block Gen. Energy Charge ($)	26,152	25,652	25,493	25,992	26,368	33,086	28,928	36,804	31,676	27,756	24,560	25,023	337,489
3rd Block Gen. Energy Charge Rate (cents/kWh)	3.008635	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	
3rd Block Gen. Energy Charge ($)	21,668	14,139	18,325	16,692	18,841	10,741	18,230	19,176	16,456	10,095	18,984	17,760	201,106
Total Generation Capacity and Energy Charges ($)	96,282	87,462	91,194	90,987	94,211	105,315	100,918	124,376	106,999	89,434	89,186	89,285	1,165,649
Surcharges													
PA Tax Adj. Surcharge on Distribution Charge (%)	0.020120	-0.052	-0.052	-0.052	-0.052	-0.052	-0.052	-0.080	-0.097	-0.097	-0.097	-0.097	
Tax Surcharge on Distribution Charge ($)	0.24	-0.59	-0.58	-0.60	-0.60	-0.76	-0.66	-1.29	-1.36	-1.19	-1.05	-1.07	-10
PA Tax Adj. Surcharge on all other charges (%)	0.008241	-0.051	-0.051	-0.051	-0.051	-0.051	-0.051	-0.062	-0.069	-0.069	-0.069	-0.069	
Tax Surcharge on all other charges ($)	11.16	-62.09	-64.90	-64.68	-67.05	-74.49	-71.73	-107.35	-102.73	-85.64	-85.94	-85.96	-861
Total PA Adjustment Taxes ($)	11.40	-62.68	-65.49	-65.28	-67.65	-75.25	-72.40	-108.64	-104.08	-86.83	-86.99	-87.03	-871
Total Electric Service Billings ($)	**$136,646**	**$122,823**	**$128,318**	**$127,913**	**$132,667**	**$147,447**	**$141,866**	**$174,676**	**$150,171**	**$125,259**	**$125,546**	**$125,596**	**$1,638,706**
Average cents per kWh	**6.17**	**6.56**	**6.42**	**6.48**	**6.42**	**6.78**	**6.49**	**6.58**	**6.58**	**6.73**	**6.37**	**6.42**	**6.50**
Excess Payment and Credit ($)							$12,003	-$12,003					$0
Late Penalties ($)												$2,511	$2,511
Total Invoice ($)	$136,646	$122,823	$128,318	$127,913	$132,557	$147,447	$153,858	$162,572	$150,171	$125,259	$125,545	$128,106	$1,641,217
Annual Load Factor (Average to Peak Day)													**66.6%**

Note 1: For the July billing, the detailed invoice was unavailable from Carlisle Barracks, so the billing determinants were estimated from the graphs provided by PPL on the August billing. The total electric service billings amount for the month is correct

Note 2: For June 2006 billing, the reported meter reading was 2,041,400 kWh, but the installation was billed at 2,175,800 kWh. The result was an overbilling of $6,111. Shown here is what was actually billed and paid.

Tobyhanna Army Depot Calendar Year 2006 Billings from PPL

PPL Rate Schedule LP-5

Cost Item/Month of Meter Reading	Jan '06	Feb '06	Mar '-6	Apr '06	May '06	June '06	July '06	Aug '06	Sept '06	Oct '06	Nov '06	Dec '06	Total
Electricity Consumed (kWh)	5,838,000	5,123,000	5,640,000	5,781,000	5,062,000	5,080,000	5,485,000	5,381,000	5,320,000	5,119,000	5,023,915	5,293,000	64,125,915
Demand (kW)	10,692	10,536	10,640	10,524	10,161	10,653	10,679	11,573	10,381	9,966	10,000	10,459	126,264
kWh Used													
Billing kW	10,692	10,536	10,640	10,524	10,161	10,653	10,679	11,573	10,381	9,966	10,000	10,459	126,264
First 200 kWh per kilowat of the Billing kW	2,138,400	2,107,200	2,128,000	2,104,800	2,032,200	2,130,600	2,135,800	2,314,600	2,076,200	1,993,200	2,000,000	2,091,800	25,252,800
Next 200 kWh per kilowat of the Billing kW	2,138,400	2,107,200	2,128,000	2,104,800	2,032,200	2,130,600	2,135,800	2,314,600	2,076,200	1,993,200	2,000,000	2,091,800	25,252,800
Additional kWh	1,561,200	908,600	1,384,000	1,571,400	997,600	818,800	1,193,400	751,800	1,167,600	1,132,600	1,023,915	1,109,400	13,620,315
Distribution Charges													
Distribution Charge Rate (cents/kW)	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	31.90	
Distribution Charge ($)	3,411	3,361	3,394	3,357	3,241	3,398	3,407	3,692	3,312	3,179	3,190	3,336	40,278
Transmission Charges													
Transmission Charge (cents/kWh)	0.585120	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	
Transmission Charge ($)	34,159	30,994	34,122	34,975	30,625	30,734	33,063	32,555	32,186	30,970	30,395	32,023	386,801
Competitive Transition Charge (CTC)													
CTC Demand Charge Rate ($/kW)	0.30455110	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	0.305	
CTC Demand Charge ($)	3,256	3,213	3,245	3,210	3,099	3,249	3,257	3,530	3,166	3,040	3,050	3,190	38,506
1st Block CTC Energy Rate (cents/kWh)	0.278726	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	
1st Block CTC Energy Charge ($)	5,960	6,027	6,086	6,020	5,812	6,094	6,108	6,620	5,938	5,701	5,720	5,983	72,067
2nd Block CTC Energy Charge Rate (cents/kWh)	0.238180	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	
2nd Block CTC Energy Charge ($)	5,093	5,142	5,192	5,136	4,959	5,199	5,211	5,648	5,066	4,863	4,880	5,104	61,492
3rd Block CTC Energy Charge Rate (cents/kWh)	0.206666	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	0.212	
3rd Block CTC Energy Charge ($)	3,226	1,926	2,934	3,331	2,115	1,736	2,530	1,594	2,475	2,401	2,171	2,352	28,792
Total CTC Charges ($)	17,536	16,308	17,458	17,697	15,985	16,277	17,107	17,391	16,645	16,005	15,821	16,628	200,857
Intangible Transition Charge (ITC)													
ITC Demand Charge Rate ($/kW)	0.93009810	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	0.901	
ITC Demand Charge ($)	9,945	9,493	9,587	9,482	9,155	9,598	9,622	10,427	9,353	8,979	9,010	9,424	114,075
1st Block ITC Energy Rate (cents/kWh)	0.849848	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	0.845	
1st Block ITC Energy Charge ($)	18,173	17,806	17,982	17,788	17,172	18,004	18,048	19,558	17,544	16,843	16,900	17,676	213,490
2nd Block ITC Energy Charge Rate (cents/kWh)	0.723878	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	0.720	
2nd Block ITC Energy Charge ($)	15,479	15,172	15,322	15,155	14,632	15,340	15,378	16,665	14,949	14,351	14,400	15,061	181,903
3rd Block ITC Energy Charge Rate (cents/kWh)	0.629877	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	0.626	
3rd Block ITC Energy Charge ($)	9,834	5,688	8,664	9,837	6,245	5,126	7,471	4,706	7,309	7,090	6,410	6,945	85,324
Total ITC Charges ($)	53,431	48,158	51,554	52,259	47,204	48,068	50,518	51,357	49,155	47,263	46,720	49,105	594,792
Generation Charge (Capacity and Energy)													
Generation Capacity Charge Rate ($/kW)	4.66848380	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	4.844	
Generation Capacity Charge ($)	49,915	51,036	51,540	50,978	49,220	51,603	51,729	56,060	50,286	48,275	48,440	50,663	609,746
1st Block Gen. Energy Rate (cents/kWh)	4.17193800	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	4.298	
1st Block Gen. Energy Charge ($)	89,213	90,567	91,461	90,464	87,344	91,573	91,797	99,482	89,235	85,668	85,960	89,906	1,082,870
2nd Block Gen. Energy Charge Rate (cents/kWh)	3.510301	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	3.616	
2nd Block Gen. Energy Charge ($)	75,064	76,196	76,948	76,110	73,484	77,042	77,231	83,696	75,075	72,074	72,320	75,639	910,881
3rd Block Gen. Energy Charge Rate (cents/kWh)	3.014362	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	3.106	
3rd Block Gen. Energy Charge ($)	47,060	28,221	42,987	48,808	30,985	25,432	37,067	23,351	36,266	35,179	31,803	34,458	421,616
Total Generation Capacity and Energy Charges ($)	261,253	246,021	262,937	266,360	241,034	245,651	257,823	262,588	250,862	241,196	238,523	250,666	3,024,913
Economic Development Initiative Credicts													
Total KW Billing Credits ($)	-9,070	-8,171	-8,506	-8,674	-7,698	-8,558	-7,698	-10,353	-8,488	-7,736	-8,120	-8,649	-101,703
Total KWH Billing Credits ($)	-35,214	-27,809	-32,680	-32,858	-28,482	-27,017	-29,769	-30,165	-30,551	-27,968	-28,886	-29,710	-361,110
Total EDI Credits ($)	-44,285	-35,981	-41,186	-41,532	-36,181	-35,575	-37,468	-40,519	-39,020	-35,703	-37,007	-38,359	-462,813
Surcharges													
PA Tax Adj. Surcharge on Distribution Charge (%)	0.015878	-0.052	-0.052	-0.052	-0.052	-0.052	-0.052	-0.083	-0.097	-0.097	-0.097	-0.097	
Tax Surcharge on Distribution Charge ($)	0.54	-1.75	-1.76	-1.75	-1.69	-1.77	-1.77	-3.07	-3.21	-3.08	-3.09	-3.24	-26
PA Tax Adj. Surcharge on all other charges (%)	0.004757	-0.051	-0.051	-0.051	-0.051	-0.051	-0.051	-0.063	-0.069	-0.069	-0.069	-0.069	
Tax Surcharge on all other charges ($)	15.32	-155.81	-165.69	-168.18	-152.32	-155.63	-163.73	-205.06	-213.78	-206.81	-203.17	-213.94	-1,989
Total PA Adjustment Taxes ($)	15.86	-157.55	-167.46	-169.92	-154.01	-157.40	-165.50	-208.13	-216.99	-209.90	-206.27	-217.18	-2,014
Total Electric Service Billings ($)	**$325,621**	**$308,705**	**$328,111**	**$332,946**	**$301,754**	**$308,396**	**$324,286**	**$326,866**	**$312,923**	**$302,699**	**$297,435**	**$313,183**	**$3,782,813**
Average cents per kWh	**5.58**	**6.03**	**5.82**	**5.76**	**5.96**	**6.07**	**5.93**	**6.07**	**5.88**	**5.91**	**5.92**	**5.92**	**5.90**
Annual Load Factor (Average to Peak Day)													**63.3%**

Note 1: For the November billing, the detailed invoice was unavailable from Tobyhanna Army Depot, so the billing determinants were estimated from the graphs provided by PPL on the subsequent billing. The total electric service billing amount for the month is correct.

Exhibit KLK-3 Schedule 3
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Direct Testimony of K. L. Kincel for DOD/FEA
July 6, 2007

US Navy at Mechanicsburg Recent Billings from PPL

PPL Rate Schedule LP-6

Cost Item/Month of Meter Reading	Feb '06	Mar '-6	Apr '06	May '06	June '06	July '06	Aug '06	Sept '06	Oct '06	Nov '06	Dec '06	Jan '07	Total
Electricity Consumed (kWh)	5,459,000	5,353,000	5,185,000	5,390,000	5,414,000	5,983,000	6,347,000	5,671,600	4,995,000	5,800,000	5,555,000	5,717,000	66,869,600
Demand (kW)	10,973	10,757	10,152	10,152	11,578	12,118	12,593	11,617	10,411	10,066	10,822	11,146	132,381
kWh Used													
Billing kW	10,973	10,757	10,152	10,152	11,578	12,118	12,593	11,617	10,411	10,066	10,822	11,146	132,385
First 200 kWh per kilowat of the Billing kW	4,389,200	4,302,800	4,060,800	4,060,800	4,631,200	4,847,200	5,037,200	4,646,800	4,164,400	4,026,400	4,328,800	4,458,400	52,954,000
Next 200 kWh per kilowat of the Billing kW	1,069,800	1,050,200	1,124,200	1,329,200	782,800	1,135,800	1,309,800	1,024,800	830,600	1,773,600	1,226,200	1,258,600	13,915,600
Additional kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Charges													
Distribution Charge Rate (cents/kW)	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	23.10	16.83	
Distribution Charge ($)	2,535	2,485	2,345	2,345	2,674	2,799	2,909	2,684	2,405	2,325	2,500	1,876	29,882
Transmission Charges													
Transmission Charge (cents/kWh)	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.570	
Transmission Charge ($)	33,027	32,386	31,369	32,610	32,755	36,197	38,399	34,313	30,220	35,090	33,608	32,609	402,582
Competitive Transition Charge (CTC)													
CTC Demand Charge Rate ($/kW)	-0.875	-0.875	-0.875	-0.875	-0.875	-0.875	-0.875	-0.875	-0.875	-0.875	-0.875	-0.478	
CTC Demand Charge ($)	-9,601	-9,412	-8,883	-8,883	-10,131	-10,603	-11,019	-10,165	-9,110	-8,808	-9,469	-5,332	-111,416
1st Block CTC Energy Rate (cents/kWh)	-0.711	-0.711	-0.711	-0.711	-0.711	-0.711	-0.711	-0.711	-0.711	-0.711	-0.711	-0.388	
1st Block CTC Energy Charge ($)	-31,207	-30,593	-28,872	-28,872	-32,928	-34,464	-35,814	-33,039	-29,609	-28,628	-30,778	-17,310	-362,114
2nd Block CTC Energy Charge Rate (cents/kWh)	-0.440	-0.440	-0.440	-0.440	-0.440	-0.440	-0.440	-0.440	-0.440	-0.440	-0.440	-0.241	
2nd Block CTC Energy Charge ($)	-4,707	-4,621	-4,946	-5,848	-3,444	-4,998	-5,763	-4,509	-3,655	-7,804	-5,395	-3,030	-58,721
3rd Block CTC Energy Charge Rate (cents/kWh)	-0.354	-0.354	-0.354	-0.354	-0.354	-0.354	-0.354	-0.354	-0.354	-0.354	-0.354	-0.182	
3rd Block CTC Energy Charge ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total CTC Charges ($)	-45,516	-44,626	-42,702	-43,604	-46,503	-50,064	-52,596	-47,713	-42,373	-45,239	-45,642	-25,672	-532,250
Intangible Transition Charge (ITC)													
ITC Demand Charge Rate ($/kW)	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	1.75	
ITC Demand Charge ($)	24,141	23,665	22,334	22,334	25,472	26,660	27,705	25,557	22,904	22,145	23,808	19,454	286,180
1st Block ITC Energy Rate (cents/kWh)	1.783	1.783	1.783	1.783	1.783	1.783	1.783	1.783	1.783	1.783	1.783	1.414	
1st Block ITC Energy Charge ($)	78,259	76,719	72,404	72,404	82,574	86,426	89,813	82,852	74,251	71,791	77,183	63,060	927,737
2nd Block ITC Energy Charge Rate (cents/kWh)	1.107	1.107	1.107	1.107	1.107	1.107	1.107	1.107	1.107	1.107	1.107	0.879	
2nd Block ITC Energy Charge ($)	11,843	11,626	12,445	14,714	8,666	12,573	14,499	11,345	9,195	19,634	13,574	11,060	151,173
3rd Block ITC Energy Charge Rate (cents/kWh)	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.893	0.698	
3rd Block ITC Energy Charge ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total ITC Charges ($)	114,243	112,010	107,183	109,453	116,711	125,658	132,017	119,754	106,350	113,570	114,565	93,574	1,365,069
Generation Charge (Capacity and Energy)													
Generation Capacity Charge Rate ($/kW)	4.732	4.732	4.732	4.732	4.732	4.732	4.732	4.732	4.732	4.732	4.732	4.789	
Generation Capacity Charge ($)	51,924	50,902	48,039	48,039	54,787	57,342	59,590	54,972	49,265	47,632	51,210	53,379	627,082
1st Block Gen. Energy Rate (cents/kWh)	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	3.956	4.002	
1st Block Gen. Energy Charge ($)	173,637	170,219	160,645	160,645	183,210	191,755	199,272	183,827	164,744	159,284	171,247	178,418	2,096,904
2nd Block Gen. Energy Charge Rate (cents/kWh)	2.339	2.339	2.339	2.339	2.339	2.339	2.339	2.339	2.339	2.339	2.339	2.367	
2nd Block Gen. Energy Charge ($)	25,023	24,564	26,295	31,090	18,310	26,566	30,636	23,970	19,428	41,485	28,681	29,792	325,839
3rd Block Gen. Energy Charge Rate (cents/kWh)	1.826	1.826	1.826	1.826	1.826	1.826	1.826	1.826	1.826	1.826	1.826	1.850	
3rd Block Gen. Energy Charge ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Generation Capacity and Energy Charges ($)	250,584	245,685	234,980	239,775	256,307	275,664	289,498	262,769	233,436	248,401	251,138	261,589	3,049,825
Surcharges													
PA Tax Adj. Surcharge on Distribution Charge (%)	-0.052	-0.052	-0.052	-0.052	-0.052	-0.055	-0.097	-0.097	-0.097	-0.097	-0.097	-0.052	
Tax Surcharge on Distribution Charge ($)	-1.32	-1.29	-1.22	-1.22	-1.39	-1.54	-2.82	-2.60	-2.33	-2.26	-2.42	-0.98	-21
PA Tax Adj. Surcharge on all other charges (%)	-0.051	-0.051	-0.051	-0.051	-0.051	-0.052	-0.069	-0.069	-0.069	-0.069	-0.069	0.113	
Tax Surcharge on all other charges ($)	-179.69	-176.18	-168.72	-172.50	-183.23	-202.24	-281.05	-254.70	-226.07	-242.76	-244.03	410.69	-1,920
Total PA Adjustment Taxes ($)	-181.01	-177.47	-169.94	-173.72	-184.62	-203.78	-283.87	-257.30	-228.40	-245.01	-246.46	409.71	-1,942
Total Electric Service Billings ($)	**$364,691**	**$347,762**	**$333,006**	**$340,404**	**$361,760**	**$390,061**	**$409,943**	**$371,660**	**$329,810**	**$363,902**	**$355,922**	**$364,386**	**$4,313,186**
Average cents per kWh	**6.60**	**6.50**	**6.42**	**6.32**	**6.68**	**6.52**	**6.46**	**6.55**	**6.60**	**6.10**	**6.41**	**6.37**	**6.45**
DSM Project Billings ($)	76,540	76,540	76,540	76,540	76,540	76,540	76,540	76,540	76,540	76,540	76,540	76,540	918,479
Total Invoice ($)	**$431,231**	**$424,302**	**$409,546**	**$416,944**	**$438,300**	**$466,591**	**$486,483**	**$448,090**	**$406,350**	**$430,442**	**$432,461**	**$440,926**	**$5,231,664**
Annual Load Factor (Average to Peak Day)													**60.6%**

Note 1: For the September billing, the detailed invoice was unavailable from US Navy at Mechanicsburg, so the billing determinants were estimated from the graphs provided by PPL on the subsequent billing. The total electric service billing amount for the month is correct.

Exhibit KLK-4
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Direct Testimony of K. L. Kincel for DOD/FEA
July 6, 2007

DOD/FEA Allocation of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Proposed Cost of Service Study
Assuming Commission Rejection of Remand Settlement Agreement
$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
Rate Class	Rate Base	Distribution RR at Present Rates	Class Return at Present Rates			Dist. RR at PPL's Proposed Rates	PPL's % Increase in Dist. RR at Proposed Rates		Class Return at PPL's Proposed Rates			Gross-Up Factor	DOD/FEA Proposed RROR at PPL's Proposed RR	DOD/FEA Proposed Return		DOD/FEA RR Increase Allocation	DOD/FEA Class RR Percent Increase	Rate Class
	$	$	$	%	RROR	$	$	%	$	%	RROR			$	%	$	%	
RS	1,321,699	384,053	48,002	3.63%	0.59	461,382	77,329	20.1%	90,137	6.82%	0.82		0.95	105,137	7.95%	104,941	27.3%	RS
RTS	38,737	3,711	-1,671	-4 31%	-0.71	4,655	944	25.4%	-1,155	-2.98%	-0 36		-0 27	-863	-2.23%	1,484	40.0%	RTS
GS-1	179,448	76,537	23,463	13.08%	2.14	77,382	845	1.1%	23,901	13.32%	1.59		1 25	18,749	10.45%	-8,658	-11.3%	GS-1
GS-3	298,479	117,481	39,215	13 14%	2.15	118,093	612	0.5%	39,524	13.24%	1.58		1.25	31,186	10 45%	-14,747	-12.6%	GS-3
LP-4	75,648	30,649	10,462	13 83%	2.26	30,258	-391	-1.3%	10,241	13.54%	1.62		1.25	7,904	10 45%	-4,698	-15 3%	LP-4
ISP	3,836	1,911	732	19 08%	3.12	1,804	-107	-5.6%	673	17.54%	2.10		1.25	401	10.45%	-608	-31.8%	ISP
LP-5	3,072	1,832	637	20.74%	3 39	1,697	-135	-7.4%	562	18.29%	2.19		1 25	321	10.45%	-580	-31.7%	LP-5
IST	820	777	340	41.46%	6.79	650	-127	-16.3%	271	33.05%	3.95		1.25	86	10 45%	-467	-60.1%	IST
LP-6	294	155	52	17.69%	2.89	150	-5	-3.2%	49	16.67%	1.99		1.25	31	10.45%	-39	-25.2%	LP-6
LPEP	821	334	114	13.89%	2 27	333	-1	-0.3%	113	13.76%	1.65		1.25	86	10.45%	-52	-15.5%	LPEP
ISA	190	574	300	157.89%	25.84	580	6	1.0%	303	159.47%	19.08		19 08	303	159 47%	6	1.0%	ISA
GH	21,654	7,093	1,992	9 20%	1.51	7,635	542	7.6%	2,288	10.57%	1 26		1.25	2,262	10.45%	497	7.0%	GH
SL/AL	78,174	16,100	-24	-0.03%	-0.01	20,107	4,007	24 9%	2,178	2.79%	0 33		0.53	3,482	4 45%	6,440	40.0%	SL/AL
LS-S	94	33	6	6.38%	1.04	35	2	6.1%	8	8 51%	1.02		1.00	8	8.36%	3	10.3%	LS-S
Total*	2,022,956	641,240	123,620	6 11%	1.00	724,761	83,521	13.0%	169,093	8.36%	1.00	1.84	1.00	169,093	8.36%	83,521	13.0%	Total*

Source Exhibit JMK-2, Section 2 which is PPL's Proposed Cost Allocation Study.
Columns 2 through 7 were taken from Exhibit JMK-2; values in the remaining columns are derived.
Column 9 The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater then 1.25 at present rates; the RROR for the residential class is derived after all other class RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR increase is set equal to the PPL proposed RR increase.
Column 13: The increase to both the RTS and the SL/AL Class is held to 40% to avoid "rate shock."
Column 9. The increase to the LS-S class is limited to bring the GH rate class to the system average return percentage.
RR = Revenue Requirements; RROR = relative rate of return, i e, the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Exhibit JMK-2 due to rounding

Exhibit KLK-5
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Direct Testimony of K. L. Kincel for DOD/FEA
July 6, 2007

DOD/FEA Allocation of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Proposed Cost of Service Study
Assuming Commission Adoption of Remand Settlement Agreement

$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
Rate Class	Rate Base $	Distribution RR at Present Rates $	Class Return at Present Rates			Dist. RR at PPL's Proposed Rates $	PPL's % Increase in Dist. RR at Proposed Rates		Class Return at PPL's Proposed Rates			Gross-Up Factor	DOD/FEA Proposed RROR at PPL's Proposed RR	DOD/FEA Proposed Return		DOD/FEA RR Increase Allocation $	DOD/FEA Class RR Percent Increase %	Rate Class
			$	%	RROR		$	%	$	%	RROR			$	%			
RS	1,321,699	394,660	53,867	4.08%	0.66	471,991	77,329	19.6%	96,005	7.26%	0.67		0.98	106,744	8.08%	97,116	24.6%	RS
RTS	38,737	4,019	-1,508	-3.89%	-0.63	4,963	944	23.5%	-992	-2.56%	-0.31		-0.29	-939	-2.42%	1,045	26.0%	RTS
GS-1	179,448	74,956	22,606	12.60%	2.05	75,801	845	1.1%	23,043	12.84%	1.53		1.25	18,819	10.49%	-6,958	-9.3%	GS-1
GS-3	298,479	111,307	35,821	12.00%	1.95	111,919	612	0.5%	36,130	12.10%	1.44		1.25	31,302	10.49%	-8,300	-7.5%	GS-3
LP-4	75,648	29,223	9,678	12.79%	2.08	28,832	-391	-1.3%	9,457	12.50%	1.49		1.25	7,933	10.49%	-3,204	-11.0%	LP-4
ISP	3,836	1,876	713	18.59%	3.03	1,769	-107	-5.7%	654	17.05%	2.03		1.25	402	10.49%	-571	-30.4%	ISP
LP-5	3,072	1,282	334	10.87%	1.77	1,147	-135	-10.5%	259	8.43%	1.00		1.25	322	10.49%	-22	-1.7%	LP-5
IST	820	602	244	29.76%	4.84	475	-127	-21.1%	175	21.34%	2.54		1.25	86	10.49%	-290	-48.2%	IST
LP-6	294	52	-5	-1.70%	-0.28	47	-5	-9.6%	-7	-2.38%	-0.28		0.10	2	0.80%	14	26.0%	LP-6
LPEP	821	336	115	14.01%	2.28	335	-1	-0.3%	114	13.89%	1.66		1.25	86	10.49%	-53	-15.8%	LPEP
ISA	190	574	300	157.89%	25.71	580	6	1.0%	303	159.47%	19.01		19.01	303	159.47%	6	1.0%	ISA
GH	21,654	6,452	1,639	7.57%	1.23	6,994	542	8.4%	1,935	8.94%	1.07		1.00	1,817	8.39%	326	5.1%	GH
SL/AL	78,174	16,942	440	0.56%	0.09	20,949	4,007	23.7%	2,642	3.38%	0.40		0.43	2,838	3.63%	4,405	26.0%	SL/AL
LS-S	94	23	1	1.06%	0.17	25	2	8.7%	2	2.13%	0.25		0.54	4	4.53%	6	26.0%	LS-S
Total*	2,022,966	642,304	124,245	6.14%	1.00	725,827	83,521	13.0%	169,720	8.39%	1.00	1.84	1.00	169,720	8.39%	83,521	13.0%	Total*

Source: Exhibit JMK-2A, Section 2.
Columns 2 through 7 were taken from Exhibit JMK-2A; values in the remaining columns are derived
Column 9: The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater than 1.25 at present rates; the RROR for the residential class is derived after all other class RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR increase is set equal to the PPL proposed RR increase.
Column 13: The increase to the RTS, LP-6, SL/AL and LS-S Classes are held to 26% to avoid "rate shock."
Column 9: The increase to the GH class is limited to bring the GH rate class to the system average return percentage
RR = Revenue Requirements; RROR = relative rate of return, i.e. the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Exhibit JMK-2A due to rounding

Exhibit KLK-6
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Direct Testimony of K. L. Kincel for DOD/FEA
July 6, 2007

DOD/FEA Allocation of 65% of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Proposed Cost of Service Study
Assuming Commission Rejection of Remand Settlement Agreement
$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
Rate Class	Rate Base	Distribution RR at Present Rates	Class Return at Present Rates			Dist. RR at PPL's Proposed Rates	PPL's % Increase in Dist. RR at Proposed Rates		Class Return at PPL's Proposed Rates			Gross-Up Factor	DOD/FEA Proposed RROR	DOD/FEA Proposed Return		DOD/FEA RR Increase Allocation	DOD/FEA Class RR Percent Increase	Rate Class
	$	$	$	%	RROR	$	$	%	$	%	RROR			$	%	$	%	
RS	1,321,699	384,053	48,002	3 63%	0.59	461,382	77,329	20.1%	90,137	6.82%	0.82		0.95	94,965	7.19%	86,258	22.5%	RS
RTS	38,737	3,711	-1,671	-4.31%	-0.71	4,655	944	25 4%	-1,155	-2.98%	-0.36		-0 29	-863	-2.23%	1,484	40 0%	RTS
GS-1	179,448	76,537	23,463	13.08%	2.14	77,382	845	1.1%	23,901	13.32%	1.59		1.25	16,985	9 46%	-11,899	-15.5%	GS-1
GS-3	298,479	117,481	39,215	13 14%	2.15	118,093	612	0.5%	39,524	13.24%	1.58		1.25	28,251	9 46%	-20,138	-17.1%	GS-3
LP-4	75,648	30,649	10,462	13.83%	2.26	30,258	-391	-1.3%	10,241	13.54%	1.82		1.25	7,160	9 46%	-6,065	-19.8%	LP-4
ISP	3,836	1,911	732	19 08%	3.12	1,804	-107	-5 6%	673	17.54%	2.10		1.25	363	9 46%	-678	-35.5%	ISP
LP-5	3,072	1,832	637	20.74%	3.39	1,697	-135	-7.4%	562	18 29%	2.19		1.25	291	9.46%	-636	-34.7%	LP-5
IST	820	777	340	41.46%	6 79	650	-127	-16.3%	271	33.05%	3.95		1.25	78	9 46%	-482	-62 0%	IST
LP-6	294	155	52	17.69%	2.89	150	-5	-3.2%	49	16.67%	1.99		1.25	28	9 46%	-44	-28 6%	LP-6
LPEP	821	334	114	13 89%	2.27	333	-1	-0.3%	113	13.76%	1.65		1.25	78	9 46%	-67	-20.0%	LPEP
ISA	190	574	300	157.89%	25 84	580	6	1.0%	303	159 47%	19 08		19 08	303	159.47%	6	1.0%	ISA
GH	21,654	7,093	1,992	9 20%	1.51	7,635	542	7.6%	2,288	10 57%	1.26		1.25	2,050	9 46%	106	1.5%	GH
SL/AL	78,174	16,100	-24	-0.03%	-0 01	20,107	4,007	24.9%	2,178	2.79%	0.33		0.59	3,482	4 45%	6,440	40.0%	SL/AL
LS-S	94	33	6	6 38%	1.04	35	2	6.1%	8	8 51%	1.02		1.00	8	8 36%	3	10.3%	LS-S
Total*	2,022,966	641,240	123,620	6 11%	1.00	724,761	83,521	13.0%	169,093	8.36%	1.00	1.84	1.00	153,177	7.57%	54,289	8.5%	Total*

Scale Back of PPL Proposed RR to % of Original Request	65%	
Target Total Revenue Requirement Increase =	54,289	8.5%
Total Return at Scaled Back RR =	153,177	
System Average ROR at Scaled Back RR =	7.57%	

This Table assumes that the Revenue Requirement Increase request by PPL is reduced by 35% in this proceeding.
Source. Exhibit JMK-2, Section 2 which is PPL's Proposed Cost Allocation Study.
Columns 2 through 7 were taken from Exhibit JMK-2; values in the remaining columns are derived
Column 9: The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater than 1.25 at present rates; the RROR for the residential class is derived after all other class RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR Increase is set equal to the PPL proposed RR increase
Column 13 The increase to both the RTS and the SL/AL Class is held to 40% to avoid "rate shock."
Column 9. The increase to the LS-S class is limited to bring the GH rate class to the system average return percentage.
RR = Revenue Requirements; RROR = relative rate of return, i.e. the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Exhibit JMK-2 due to rounding

Exhibit KLK-7
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Direct Testimony of K. L. Kincel for DOD/FEA
July 6, 2007

DOD/FEA Allocation of 65% of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Proposed Cost of Service Study
Assuming Commission Adoption of Remand Settlement Agreement

$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
Rate Class	Rate Base $	Distribution RR at Present Rates $	Class Return at Present Rates $	%	RROR	Dist. RR at PPL's Proposed Rates $	PPL's % Increase in Dist. RR at Proposed Rates $	%	Class Return at PPL's Proposed Rates $	%	RROR	Gross-Up Factor	DOD/FEA Proposed RROR at PPL's Proposed RR	DOD/FEA Proposed Return $	%	DOD/FEA RR Increase Allocation $	DOD/FEA Class RR Percent Increase %	Rate Class
RS	1,321,699	394,660	53,867	4.08%	0.66	471,991	77,329	19.6%	96,005	7.26%	0.87		0.96	96,526	7.30%	78,350	19.9%	RS
RTS	38,737	4,019	-1,508	-3.89%	-0.63	4,963	944	23.5%	-992	-2.56%	-0.31		-0.32	-939	-2.42%	1,045	26.0%	RTS
GS-1	179,448	74,956	22,606	12.60%	2.05	75,801	845	1.1%	23,043	12.84%	1.53		1.25	17,054	9.50%	-10,197	-13.6%	GS-1
GS-3	298,479	111,307	35,821	12.00%	1.95	111,919	612	0.5%	36,130	12.10%	1.44		1.25	28,366	9.50%	-13,692	-12.3%	GS-3
LP-4	75,648	29,223	9,678	12.79%	2.08	28,832	-391	-1.3%	9,457	12.50%	1.49		1.25	7,189	9.50%	-4,571	-15.6%	LP-4
ISP	3,836	1,876	713	18.59%	3.03	1,769	-107	-5.7%	654	17.05%	2.03		1.25	365	9.50%	-640	-34.1%	ISP
LP-5	3,072	1,282	334	10.87%	1.77	1,147	-135	-10.5%	259	8.43%	1.00		1.25	292	9.50%	-77	-6.0%	LP-5
IST	820	602	244	29.76%	4.84	475	-127	-21.1%	175	21.34%	2.54		1.25	78	9.50%	-305	-50.7%	IST
LP-6	294	52	-5	-1.70%	-0.28	47	-5	-9.6%	-7	-2.38%	-0.28		0.11	2	0.60%	14	26.0%	LP-6
LPEP	821	336	115	14.01%	2.28	335	-1	-0.3%	114	13.89%	1.66		1.25	78	9.50%	-68	-20.2%	LPEP
ISA	190	574	300	157.89%	25.71	580	6	1.0%	303	159.47%	19.01		19.01	303	159.47%	6	1.0%	ISA
GH	21,654	6,452	1,639	7.57%	1.23	6,994	542	8.4%	1,935	8.94%	1.07		1.00	1,646	7.60%	13	0.2%	GH
SL/AL	78,174	16,942	440	0.56%	0.09	20,949	4,007	23.7%	2,642	3.38%	0.40		0.48	2,838	3.63%	4,405	26.0%	SL/AL
LS-S	94	23	1	1.06%	0.17	25	2	8.7%	2	2.13%	0.25		0.60	4	4.53%	6	26.0%	LS-S
Total*	2,022,966	642,304	124,245	6.14%	1.00	725,827	83,521	13.0%	169,720	8.39%	1.00	1.64	1.00	153,604	7.60%	54,289	8.5%	Total*

Scale Back of PPL Proposed RR to % of Original Request:	65%	
Target Total Revenue Requirement Increase =	54,289	8.5%
Total Return at Scaled Back RR =	153,604	
System Average ROR at Scaled Back RR =	7.60%	

This Table assumes that the Revenue Requirement increase request by PPL is reduced by 35% in this proceeding
Source. Exhibit JMK-2A, Section 2.
Columns 2 through 7 were taken from Exhibit JMK-2A; values in the remaining columns are derived
Column 9. The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater than 1.25 at present rates; the RROR for the residential class is derived after all other class RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR increase is set equal to the PPL proposed RR increase
Column 13: The increase to the RTS, LP-6, SL/AL and LS-S Classes are held to 26% to avoid "rate shock."
Column 9. The increase to the GH class is limited to bring the GH rate class to the system average return percentage.
RR = Revenue Requirements; RROR = relative rate of return, i.e. the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Exhibit JMK-2A due to rounding

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing documents filed on behalf of the consumer interests of the United States Department of Defense and All Federal Executive Agencies were sent to the parties on the attached service list by UPS Overnight or first class mail, postage prepaid on July 5, 2007.

Dated at Arlington County, Virginia, this 5th day of July 2007.

Peter Q. Nyce, Jr.

PETER Q. NYCE, JR.

R-00072155 PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PPL ELECTRIC UTILITIES CORPORATION

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

In the Matter of:	)	
	)	
Pennsylvania Public Utility Commission et al.	)	**Docket No. R-00072155**
	)	DOCUMENT FOLDER
vs.	)	
	)	
PPL Electric Utilities Corporation	)	

DOD/FEA Statement No. 1-S

Surrebuttal Testimony

Of Kenneth L. Kincel

AUG 16 2007

Addressing Revenue Requirement Class Allocation

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FOR

U.S. DEPARTMENT OF DEFENSE
AND ALL FEDERAL EXECUTIVE AGENCIES

Date Due: August 8, 2007
Filing Due: August 8, 2007

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

In the Matter of: **Pennsylvania Public Utility Commission et al.** **vs.** **PPL Electric Utilities Corporation**	)))))))))	**Docket No. R-00072155**

Surrebuttal Testimony of Kenneth L. Kincel

Q. PLEASE STATE YOUR NAME, TITLE AND OCCUPATION.

A. My name is Kenneth L. Kincel. I am President of Decision Analysis Corporation of Virginia, an energy consulting firm located at 8009 Snowpine Way, Suite 100, McLean, Virginia. I am testifying on behalf of the consumer interests of the U. S. Department of Defense and all federal executive agencies ("DOD/FEA"). The largest military customers of PPL Electric Utilities Corporation ("PPL" or the "Company") are Tobyhanna Army Depot (Rate LP-5), Carlisle Barracks (Rate LP-5) and the U. S. Naval Support Activity in Mechanicsburg (Rate LP-6). I am the same person that submitted direct testimony in this proceeding on July 6, 2007.

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

A. The purpose of my surrebuttal testimony is to oppose the revised rate class allocation of the proposed total revenue requirement as presented by the Company in its rebuttal testimony. (See Rebuttal Testimony of Company Witness Douglas A. Krall and Exhibit JMK-2A Revised.) I will also update my recommended class allocation of the Company's proposed revenue requirement using the same methodology that I employed in my direct testimony. I will then contrast my class revenue requirement increase results with those of the Company, and address several criticisms of my revenue class allocation results which were put forth by Company Witness Douglas A. Krall within his rebuttal testimony. Finally, I will present my class revenue allocation given a possible scaleback of the total revenue requirement by the Commission to 65% of the Company's request within its rebuttal testimony. These scaleback allocation results also constitute an update to those presented within my direct testimony.

Q. WHY DO YOU OBJECT TO THE COMPANY'S REVISED PROPOSAL FOR THE ALLOCATION OF INCREASED REVENUE REQUIREMENTS BY CUSTOMER CLASS?

A. As described by Company Witness Douglass A. Krall in his rebuttal testimony (page 25-26), the Company again proposes two general criteria for allocating increased revenue requirements: (1) that the relative rate of return for each customer class moves closer (about half-way on a percentage basis for most rate classes) to 1.0, which is parity with the system average rate of return; and (2) that no customer class be burdened with an increase greater than twice the system average increase (about 25%).

The Company adds a refinement that it didn't include within its initial application, namely, that the "deficiency" from rate classes that are capped at twice the system average increase should be spread to other similar rate classes that are not capped. Thus, the RTS deficiency is allocated by the Company to the RS rate schedule class and the

LP-6 deficiency is allocated to all rate schedules taking service at 69 kV or above. The street lighting deficiency is spread to all rate schedules because "all customers share the use of street lights and receive the benefit of lower street lighting costs through lower taxes." These criteria are intended to implement two principles in rate design, namely cost-of-service and "gradualism." They sound reasonable until the Company's individual customer class results are scrutinized.

The Company's class revenue allocation results are shown in Exhibit JMK 2A Revised and are summarized in Attachment 3, Appendix A to Company Witness Oliver G. Kasper's rebuttal testimony. These results are reproduced within the first seven numbered columns of Exhibit KLK-5 Revised. As can be seen from this exhibit, enormous customer class subsidies continue to exist after the Company's class allocation methodology is applied. For example, the Company will continue to earn 2.9 times its average system return from IST customers and 1.9 times the system average return from ISP customers. Meanwhile, the Company will earn only 84% of its system average return from RS (residential) customers. <u>The Company again does not go far enough in redressing the egregious gross inequities that presently exist in distribution rates.</u> I described in my direct testimony how such egregious class cross subsidies motivate consumer behavior that wastes energy and is deleterious to the general welfare of the society. Although I will not repeat all of that here, those same arguments apply here as well.

I believe my proposed revenue allocation methodology is superior to the Company's because it also implements "gradualism" and protects against customer "rate shock," but additionally it directly eliminates all egregious customer class cross subsidies that are embedded in distribution rates.

Q. PLEASE DESCRIBE YOUR REVISED RECOMMENDED CLASS REVENUE REQUIREMENT ALLOCATION METHODOLOGY.

A. My proposed methodology is exactly the same as I advanced in my direct testimony. It is based on several premises, which I will repeat here for emphasis.

- A "just and reasonable" **set** of rates has no single rate class paying more than a defined multiple of the system average percentage return. In this case, I propose that the acceptable maximum class return be set at 125% of the system average return (i.e., a maximum class relative rate of return, or "RROR" of 1.25). This constitutes a reduction from the 150% maximum class return that I proposed in the last PPL rate case.
- Rate shock can be defined as a specific maximum allowed percent class revenue increase. In this case, I propose that rate shock be assumed to occur if a class rate increase exceeds about double the initial PPL proposed system average increase (i.e., 26%). The 26% class increase ceiling is the same as that originally proposed by the Company in this proceeding. In its rebuttal testimony, the Company reduced the class maximum increase slightly to 25%.
- A "fair" class allocation of any total revenue increase requires customer classes now paying less than the system average percentage return to incur a greater-than-average revenue increase; while customer classes now paying more than the system average percentage return should be granted a less-than-average

percentage revenue increase. My methodology will accomplish this result automatically.

- Gradualism can be implemented over several rate cases by reducing the acceptable maximum class return multiple. In this instance, I recommend that during the subsequent general rate case for PPL, all rate classes (except perhaps the RTS and SL/AL classes which have very low RROR's even after this rate increase) be brought to parity with the system average return.

The results of applying this revenue requirement allocation methodology are shown in Exhibit KLK-5 Revised, columns 9 through 13. The steps used to create these columns within these two exhibits are as follows:

1. Set all the classes with present RROR's over 1.25 to an RROR equal to 1.25, and then derive the rate increase (or rate reduction) that is needed for each class.
2. Leave the rate increase for class ISA at the PPL proposed level, since the rates for this class are set by contract agreement and are not affected by this revenue requirement allocation methodology.
3. For any rate class with a present RROR between 1.0 and 1.25, assign a rate increase that will bring the class to an RROR equal to 1.0, provided that such a rate increase will not exceed the system average rate increase. If the system average rate increase is exceeded, set the class rate increase to the system average rate increase and then derive the class return, rate of return and RROR.
4. Derive the rate increase for all remaining classes with present RROR's under 1.0 such that their class RROR's are <u>equivalent</u>. Check to ensure that the maximum allowable rate increase (26% in Exhibit KLK-5) is not exceeded by any of these

rate classes. If so, set the class rate increase to the maximum allowable class rate increase and derive the class return, rate of return and RROR for that class.

As shown in Exhibit KLK-5 Revised, the RTS, SL/AL and LP-6 classes receive the maximum 26% increase in class revenue requirement. Rate increases (or decreases) are calculated to bring each class presently paying a RROR more than 1.25 down to 1.25. Many of the customer classes now paying significant cross subsidies, such as the GS-3, LP-4, IST, LPEP and ISP classes, will receive reductions in revenue requirements that exceed 10%. The required return and corresponding rate increase for the residential class is then calculated as that sufficient to bring the total system return to the proposed percentage return. Thereby, the residential class is given a 24.9% revenue increase, which will bring this class to paying 96% of the system average percentage return within its rates. All egregious cross-subsidies have been eliminated because no customer class is forced to pay the Company more than 125% of the system average percentage return. Rate shock is eliminated because no customer class incurs an increase higher than 26%.

Q. PLEASE ADDRESS THE COMPANY'S CRITICISM OF YOUR RECOMMENDED CLASS REVENUE ALLOCATION METHODOLOGY.

A. Company Witness Krall (Rebuttal Testimony, p. 29) mischaracterizes my methodology as having a "single focus" on reducing the indexed returns of all rate classes to no more than 125% of the system average. He goes on to say that "the principal flaw in Mr. Kincel's methodology is that it does not give any real consideration to gradualism for the classes, primarily the residential class." In fact, as described above, my methodology implements gradualism by limiting any single rate class to a 26% increase. That is the exact same way that gradualism was implemented by the Company in its initial application. In its revision, the Company reduced this class ceiling increase only slightly to 25%. Thus, in addition to the cost-based principle, my methodology applies the "gradualism" principle, almost to the same extent and in the same manner as the Company does, and rests not on any "single focus." The residential (RS) class does not even incur the maximum ceiling increase; receiving only a 24.9% increase as stated above, at the full proposed total revenue increase.

Company Witness Krall further cries that my methodology requires a revenue requirement increase that exceeds the total revenue requirement increase, which he deems not to be appropriate. Yet, the Company promises to bring all customer classes to or very near parity with the system average return percentage with just one more rate case. The Company likely cannot have it both ways, given any reasonable total rate increase level in the next rate case. Within this rate case or the next, the RS class will likely be required to incur a rate increase that is more than the total revenue requirement increase if all rate classes are to be brought to or very near parity with the average system return.

The following math illustrates this point. As Mr. Baron points out (Table 1A of his Supplemental Direct Testimony), the RS class presently enjoys subsidies of about $50 million from all the other rate classes. Within this rate case, PPL is proposing to allocate to the RS class 94.2% of the total revenue requirement increase, thereby reducing the RS subsidy to about $32.8 million in revenues.[1] If PPL plans to erase this remaining RS

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[1] Obtained by multiplying 8.43% times the RS rate base of $1,335,501k to yield $112,582k, then subtracting the RS class return at PPL's proposed rates of $94,739k and multiplying the result by the gross-up factor of 1.84.

subsidy in the next rate case by again applying 94.2% of the next rate increase to the RS class, the total revenue requirement increase would have to be a staggering $112 million or more.[2]

Company Witness Krall also complains that my revenue allocation methodology would require a compliance filing with a revised cost of service study, which the Company doesn't want to perform because such an exercise will add "unneeded complexity and disputes to the compliance filing process" and perhaps cause delays in the implementation of the new rates. For one thing, I never requested a compliance cost of service study. The use of my Exhibit KLK-7 Revised should be sufficient to perform the class revenue requirement allocation as I have done, when the final total revenue requirement increase is known. However, if more precision is desired by other parties, there is ample time for the Company to prepare and all parties to review a compliance filing containing a revised cost of service study without delaying implementation of new rates that will not go into effect until January 2007.

Q. HOW WOULD YOUR PROPOSED REVENUE REQUIREMENT CLASS ALLOCATION METHODOLOGY BE IMPLEMENTED IF THERE IS A SCALE-BACK OF PPL'S REVISED PROPOSED RATE INCREASE IN THIS PROCEEDING?

A. My class allocation methodology would be implemented using the exact same steps that I have described above given any amount for the final allowed total revenue requirement

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[2] Obtained by subtracting 64.8% which is the percentage of RS distribution revenues to total distribution rate revenues with PPL's proposed rate increase from 94.2% to yield 29.4% and dividing this into $32.8 million.

increase. I have prepared Exhibit KLK-7 Revised to update my demonstration of my class allocation if PPL's currently proposed $76.98 million (12.2%) overall distribution rate increase is scaled back in this proceeding to 65% of that amount, or $50 million (7.9%). The maximum allowable class rate increases are held constant at 26% because the class threshold for "Rate Shock" is not dependent on the overall system percentage increase, but is more related to what the Commission feels any single rate class can tolerate without a public outcry. Note when comparing Exhibit KLK-5 Revised with KLK-7 Revised that most of the reduction in revenue requirements is allocated to the residential class as the total revenue requirement increase is scaled-back. Of the total scaleback of $26.9 million, $17.5 million or 65% is applied to reduce the RS revenue requirement. As a result, the RS class will receive only a 20.4% increase at the scaleback level. Even with that increase, the RS class will continue to provide only 95% of the system average rate of return within their distribution rates.

Q. HAVE YOU REVISED YOUR EXHIBITS TO REFLECT REMOVAL OF DOE CREDITS FROM PRESENT REVENUES?

A. Yes. Mr. Baron (on page 5-6 of his Supplemental Direct Testimony) highlighted the fact that the "Present" rate schedule revenues include the effects of the expiring DOE/SEF rate credits. He further concluded that the present revenues associated with the LP-6 class in particular are grossly incorrect and misleading for the revenue increase class allocation. Within DOD/FEA Interrogatory Set II, DOD/FEA asked for a correction of rate class present revenues and class returns with the effect of the DOE/SEF rate credits removed. PPL's response is shown in Attachment I, which I am formally hereby submitting for the record in this proceeding. Exhibits KLK-5R-DOE Refund Adjusted and KLK-7R-DOE Refund Adjusted present the effect of the removal of these DOE credits from present revenues when my allocation methodology is applied. Because this adjustment for removal of the expiring DOE refunds renders a more accurate presentation of 2007 class revenues under present rates, the class revenue requirement increase allocations shown in Exhibit KLK-5-DOE Refund Adjusted and Exhibit KLK-7-DOE Refund Adjusted constitute my recommended allocations to the Commission at the total PPL proposed revenue increase and the 65% scaleback level, respectively.

Q. DO YOU BELIEVE THAT YOUR RECOMMENDED CLASS REVENUE INCREASE ALLOCATION METHODOLOGY IS SUPERIOR TO THOSE PRESENTED BY PARTIES OTHER THAN PPL?

A. Yes. The allocation methodology presented by OCA is based on a cost of service study that is inconsistent with NARUC guidance for the proper allocation of distribution plant, as I discussed in great detail within my direct testimony. For this reason alone, the OCA class allocation of the revenue requirement increase should be rejected out-of-hand by the Commission. PPLICA and OSBA still must submit updated class revenue allocations based on the rebuttal testimony of the Company. But assuming the results are similar to those already filed in direct testimony, neither of these two allocation methodologies remove egregious and onerous rate class cross subsidizes as effectively as my recommended allocation methodology, as measured by RROR's.

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes it does.

Commonwealth of Virginia

County of Nelson

Before me, the undersigned Notary Public, personally appeared Kenneth L. Kincel, who being duly sworn on oath deposes and says that the foregoing prepared direct testimony, related exhibits and statement of facts contained therein are true and correct to the best of his knowledge, information and belief.

Kenneth L. Kincel

Kenneth L. Kincel
President, Decision Analysis Corporation of Virginia

Subscribed to and sworn before me on this third day of August 2007.

Notary Public

My Commission Expires: 08/31/08

Exhibit KLK-5 Revised
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Surrebuttal Testimony of K. L. Kincel for DOD/FEA
August 8, 2007

DOD/FEA Allocation of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Proposed Cost of Service Study
With Commission Adoption of Remand Settlement Agreement

$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
Rate Class	Rate Base	Distribution RR at Present Rates	Class Return at Present Rates			Dist. RR at PPL's Proposed Rates	PPL's % Increase in Dist. RR at Proposed Rates		Class Return at PPL's Proposed Rates			Gross-Up Factor	DOD/FEA Proposed RROR at PPL's Proposed RR	DOD/FEA Proposed Return		DOD/FEA RR Increase Allocation	DOD/FEA Class RR Percent Increase	Rate Class
	$	$	$	%	RROR	$	$	%	$	%	RROR			$	%	$	%	
RS	1,335,501	386,480	55,214	4.13%	0.65	458,987	72,507	18.8%	94,739	7.09%	0.84		0.96	107,710	8.07%	96,367	24.9%	RS
RTS	37,413	3,991	-1,338	-3.58%	-0.56	4,990	999	25.0%	-791	-2.11%	-0.25		-0.25	-773	-2.07%	1,038	26.0%	RTS
GS-1	181,070	73,866	22,823	12.60%	1.98	74,064	198	0.3%	22,908	12.65%	1.50		1.25	19,079	10.54%	-6,872	-9.3%	GS-1
GS-3	282,895	109,784	37,454	13.24%	2.08	108,852	-932	-0.8%	36,919	13.05%	1.55		1.25	29,809	10.54%	-14,034	-12.8%	GS-3
LP-4	75,577	29,104	10,102	13.37%	2.10	28,765	-339	-1.2%	9,912	13.12%	1.56		1.25	7,964	10.54%	-3,926	-13.5%	LP-4
ISP	3,830	1,781	688	17.96%	2.83	1,656	-125	-7.0%	619	16.16%	1.92		1.25	404	10.54%	-522	-29.3%	ISP
LP-5	3,070	1,168	376	12.25%	1.93	1,173	5	0.4%	379	12.35%	1.46		1.25	323	10.54%	-96	-8.3%	LP-5
IST	818	564	245	29.95%	4.71	475	-89	-15.8%	197	24.08%	2.86		1.25	86	10.54%	-292	-51.7%	IST
LP-6	292	36	-15	-5.14%	-0.81	45	9	25.0%	-9	-3.08%	-0.37		-0.40	-10	-3.39%	9	26.0%	LP-6
LPEP	819	333	117	14.29%	2.25	326	-7	-2.1%	114	13.92%	1.65		1.25	86	10.54%	-56	-16.9%	LPEP
ISA	189	538	283	149.74%	23.57	538	0	0.0%	283	149.74%	17.76		17.76	283	149.74%	0	0.0%	ISA
GH	20,699	6,459	1,742	8.42%	1.32	7,000	541	8.4%	2,039	9.85%	1.17		1.25	2,181	10.54%	806	12.5%	GH
SL/AL	76,063	17,518	672	0.88%	0.14	21,731	4,213	24.0%	2,989	3.83%	0.45		0.48	3,153	4.04%	4,555	26.0%	SL/AL
L5-S	94	35	8	8.51%	1.34	35	0	0.0%	8	8.51%	1.01		1.25	10	10.54%	3	10.0%	L5-S
Total*	2,020,330	631,657	128,371	6.35%	1.00	708,637	76,980	12.2%	170,306	8.43%	1.00	1.84	1.00	170,306	8.43%	76,980	12.2%	Total*

Source: Exhibit JMK-2A Revised, Section 2.
Columns 2 through 7 were taken from Exhibit JMK-2A Revised; values in the remaining columns are derived.
Column 9: The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater than 1.25 at present rates; the RROR for the residential class is derived after all other class RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR Increase is set equal to the PPL proposed RR increase.
Column 13: The increase to the RTS, LP-6, and SL/AL Classes are held to 26% to avoid "rate shock."
RR = Revenue Requirements; RROR = relative rate of return, i.e, the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Exhibit JMK-2A Revised due to rounding.

Exhibit KLK-7 Revised
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Surrebuttal Testimony of K. L. Kincel for DOD/FEA
August 8, 2007

DOD/FEA Allocation of 65% of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Proposed Cost of Service Study
With Commission Adoption of Remand Settlement Agreement

$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
													Scaleback to 65% of PPL's Requested Increase In Distribution Rate Revenue Requirements					
Rate Class	Rate Base	Distribution RR at Present Rates	Class Return at Present Rates			Dist. RR at PPL's Proposed Rates	PPL's % Increase in Dist. RR at Proposed Rates		Class Return at PPL's Proposed Rates			Gross-Up Factor	DOD/FEA Proposed RROR at 65% PPL's Proposed RR	DOD/FEA Proposed Return		DOD/FEA RR Increase Allocation	DOD/FEA Class RR Percent Increase	Rate Class
	$	$	$	%	RROR	$	$	%	$	%	RROR			$	%	$	%	
RS	1,335,501	386,480	55,214	4.13%	0.65	458,987	72,507	18.8%	94,739	7.09%	0.84		0.95	98,199	7.35%	78,907	20.4%	RS
RTS	37,413	3,991	-1,338	-3.58%	-0.56	4,990	999	25.0%	-791	-2.11%	-0.25		-0.27	-773	-2.07%	1,038	26.0%	RTS
GS-1	181,070	73,866	22,823	12.60%	1.98	74,064	198	0.3%	22,908	12.65%	1.50		1.25	17,435	9.63%	-9,891	-13.4%	GS-1
GS-3	282,895	109,784	37,454	13.24%	2.08	108,852	-932	-0.8%	36,919	13.05%	1.55		1.25	27,240	9.63%	-18,750	-17.1%	GS-3
LP-4	75,577	29,104	10,102	13.37%	2.10	28,765	-339	-1.2%	9,912	13.12%	1.56		1.25	7,277	9.63%	-5,185	-17.8%	LP-4
ISP	3,830	1,761	688	17.96%	2.83	1,656	-125	-7.0%	619	16.16%	1.92		1.25	369	9.63%	-586	-32.9%	ISP
LP-5	3,070	1,168	376	12.25%	1.93	1,173	5	0.4%	379	12.35%	1.46		1.25	296	9.63%	-146	-12.6%	LP-5
IST	818	564	245	29.95%	4.71	475	-89	-15.8%	197	24.08%	2.86		1.25	79	9.63%	-305	-54.1%	IST
LP-6	292	36	-15	-5.14%	-0.81	45	9	25.0%	-9	-3.08%	-0.37		-0.44	-10	-3.39%	9	26.0%	LP-6
LPEP	819	333	117	14.29%	2.25	326	-7	-2.1%	114	13.92%	1.65		1.25	79	9.63%	-70	-21.0%	LPEP
ISA	189	538	283	149.74%	23.57	538	0	0.0%	283	149.74%	17.76		17.76	283	149.74%	0	0.0%	ISA
GH	20,699	6,459	1,742	8.42%	1.32	7,000	541	8.4%	2,039	9.85%	1.17		1.25	1,993	9.63%	461	7.1%	GH
SL/AL	78,063	17,518	672	0.86%	0.14	21,731	4,213	24.0%	2,989	3.83%	0.45		0.52	3,153	4.04%	4,555	26.0%	SL/AL
LS-S	94	35	8	8.51%	1.34	35	0	0.0%	8	8.51%	1.01		1.25	9	9.63%	2	5.5%	LS-S
Total*	2,020,330	631,657	128,371	6.35%	1.00	708,637	76,980	12.2%	170,306	8.43%	1.00	1.64	1.00	155,629	7.70%	50,037	7.9%	Total*

Scale Back of PPL Proposed RR to % of Original Request:	65%	
Target Total Revenue Requirement Increase =	50,037	7.9%
Total Return at Scaled Back RR =	155,629	
System Average ROR at Scaled Back RR =	7.70%	

This Table assumes that the Revenue Requirement increase request by PPL is reduced by 35% in this proceeding.
Source: Exhibit JMK-2A Revised, Section 2.
Columns 2 through 7 were taken from Exhibit JMK-2A Revised; values in the remaining columns are derived.
Column 9: The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater than 1.25 at present rates; the RROR for the residential class is derived after all other class RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR increase is set equal to the PPL proposed RR increase.
Column 13: The increase to the RTS, LP-6, and SL/AL Classes are held to 26% to avoid "rate shock."
RR = Revenue Requirements; RROR = relative rate of return, i.e. the class return percentage divided by the system average return percentage.
* Slight differences occur in totals when compared to corresponding columns on Exhibit JMK-2A Revised due to rounding.

DOD/FEA Allocation of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Response to DOD Interrogatory Set II
With Present Revenues Adjusted for Expiring DOE Refunds

$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
Rate Class	Rate Base $	Distribution RR at Present Rates $	Class Return at Present Rates $	%	RROR	Dist. RR at PPL's Proposed Rates $	PPL's % Increase in Dist. RR at Proposed Rates $	%	Class Return at PPL's Proposed Rates $	%	RROR	Gross-Up Factor	DOD/FEA Proposed RROR at PPL's Proposed RR	DOD/FEA Proposed Return $	%	DOD/FEA RR Increase Allocation $	DOD/FEA Class RR Percent Increase %	Rate Class
RS	1,335,501	387,108	55,563	4.16%	0.65	458,299	71,191	18.4%	94,361	7.07%	0.84		0.96	107,673	8.06%	95,694	24.7%	RS
RTS	37,413	4,009	-1,328	-3.55%	-0.55	5,011	1,002	25.0%	-779	-2.08%	-0.25		-0.24	-760	-2.03%	1,042	26.0%	RTS
GS-1	181,070	73,955	22,871	12.63%	1.97	74,021	66	0.1%	22,884	12.64%	1.50		1.25	19,079	10.54%	-8,963	-9.4%	GS-1
GS-3	282,895	110,181	37,672	13.32%	2.08	108,995	-1,186	-1.1%	36,998	13.08%	1.55		1.25	29,808	10.54%	-14,441	-13.1%	GS-3
LP-4	75,577	29,370	10,248	13.56%	2.12	28,946	-424	-1.4%	10,012	13.25%	1.57		1.25	7,963	10.54%	-4,195	-14.3%	LP-4
ISP	3,830	1,797	697	18.20%	2.84	1,666	-131	-7.3%	624	16.29%	1.93		1.25	404	10.54%	-539	-30.0%	ISP
LP-5	3,070	1,314	456	14.85%	2.32	1,273	-41	-3.1%	433	14.10%	1.67		1.25	323	10.54%	-243	-18.5%	LP-5
IST	818	656	296	36.19%	5.65	538	-118	-18.0%	231	28.24%	3.35		1.25	86	10.54%	-385	-58.7%	IST
LP-6	292	53	-5	-1.71%	-0.27	66	13	24.5%	2	0.68%	0.08		0.10	3	0.86%	14	26.0%	LP-6
LPEP	819	336	119	14.53%	2.27	327	-9	-2.7%	114	13.92%	1.65		1.25	86	10.54%	-80	-17.9%	LPEP
ISA	189	553	292	154.50%	24.14	553	0	0.0%	292	154.50%	18.33		18.33	292	154.50%	0	0.0%	ISA
GH	20,699	6,475	1,751	8.46%	1.32	7,001	526	8.1%	2,039	9.85%	1.17		1.25	2,181	10.54%	790	12.2%	GH
SL/AL	78,063	17,523	675	0.86%	0.14	21,904	4,381	25.0%	3,084	3.95%	0.47		0.48	3,156	4.04%	4,556	26.0%	SL/AL
LS-S	94	35	8	8.51%	1.33	37	2	5.7%	9	9.57%	1.14		1.25	10	10.54%	3	10.0%	LS-S
*Total**	*2,020,330*	*633,365*	*129,315*	6.40%	1.00	708,637	75,272	11.9%	170,304	8.43%	1.00	1.84	1.00	170,304	8.43%	75,272	11.9%	Total*

Source: Exhibit JMK-2A Revised DOE Refund Adjusted.
Columns 2 through 7 were taken from Exhibit JMK-2A Revised DOE Refund Adjusted; values in the remaining columns are derived.
Column 9: The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater than 1.25 at present rates; the RROR for the residential class is derived after all other class RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR increase is set equal to the PPL proposed RR increase.
Column 13: The increase to the RTS, LP-6, and SL/AL Classes are held to 26% to avoid "rate shock."
RR = Revenue Requirements; RROR = relative rate of return, i.e. the class return percentage divided by the system average return percentage.

Exhibit KLK-7 Revised DOE Refund Adjusted
PPL Electric Utilities Corporation
PPUC Docket No. R-00072155
Surrebuttal Testimony of K. L. Kincel for DOD/FEA
August 8, 2007

DOD/FEA Allocation of 65% of PPL's Proposed Total Distribution Revenue Requirements Increase By Customer Class
Based on PPL's Response to DOD Interrogatory Set II
With Present Revenues Adjusted for Expiring DOE Refunds
$ (Thousands)

(1)	(2)	(3)	(4)			(5)	(6)		(7)			(8)	(9)	(10)	(11)	(12)	(13)	(1)
													Scaleback to 65% of PPL's Requested Increase In Distribution Rate Revenue Requirements					
Rate Class	Rate Base $	Distribution RR at Present Rates $	Class Return at Present Rates $	%	RROR	Dist. RR at PPL's Proposed Rates $	PPL's % Increase In Dist. RR at Proposed Rates $	%	Class Return at PPL's Proposed Rates $	%	RROR	Gross-Up Factor	DOD/FEA Proposed RROR at 65% PPL's Proposed RR	DOD/FEA Proposed Return $	%	DOD/FEA RR Increase Allocation $	DOD/FEA Class RR Percent Increase %	Rate Class
RS	1,335,501	387,108	55,563	4.16%	0.49	456,299	71,191	18.4%	94,361	7.07%	0.74		0.95	98,376	7.37%	78,621	20.3%	RS
RTS	37,413	4,009	-1,328	-3.55%	-0.42	5,011	1,002	25.0%	-779	-2.08%	-0.22		-0.26	-760	-2.03%	1,042	26.0%	RTS
GS-1	161,070	73,955	22,871	12.63%	1.48	74,021	66	0.1%	22,884	12.64%	1.32		1.25	17,472	9.65%	-9,915	-13.4%	GS-1
GS-3	282,895	110,181	37,672	13.32%	1.56	105,995	-1,186	-1.1%	36,998	13.08%	1.37		1.25	27,297	9.65%	-19,052	-17.3%	GS-3
LP-4	75,577	29,370	10,248	13.56%	1.59	28,946	-424	-1.4%	10,012	13.25%	1.38		1.25	7,293	9.65%	-5,427	-18.5%	LP-4
ISP	3,830	1,797	697	18.20%	2.14	1,666	-131	-7.3%	624	16.29%	1.70		1.25	370	9.65%	-601	-33.5%	ISP
LP-5	3,070	1,314	456	14.85%	1.75	1,273	-41	-3.1%	433	14.10%	1.47		1.25	296	9.65%	-293	-22.3%	LP-5
IST	818	656	296	36.19%	4.25	538	-118	-18.0%	231	28.24%	2.95		1.25	79	9.65%	-399	-60.8%	IST
LP-6	292	53	-5	-1.71%	-0.20	66	13	24.5%	2	0.68%	0.07		0.11	3	0.86%	14	26.0%	LP-6
LPEP	819	336	119	14.53%	1.71	327	-9	-2.7%	114	13.92%	1.45		1.25	79	9.65%	-73	-21.8%	LPEP
ISA	189	553	292	154.50%	18.15	553	0	0.0%	292	154.50%	16.14		16.14	292	154.50%	0	0.0%	ISA
GH	20,699	6,475	1,751	8.46%	0.99	7,001	526	8.1%	2,039	9.85%	1.03		1.25	1,997	9.65%	452	7.0%	GH
SL/AL	78,063	17,523	675	0.86%	0.10	21,904	4,381	25.0%	3,084	3.95%	0.41		0.52	3,156	4.04%	4,556	26.0%	SL/AL
LS-S	94	35	8	8.51%	1.00	37	2	5.7%	9	9.57%	1.00		1.25	9	9.65%	2	5.6%	LS-S
Total*	2,020,330	533,365	129,315	6.40%	1.00	708,637	75,272	11.9%	170,304	8.43%	1.00	1.84	1.00	155,958	7.72%	48,927	7.7%	Total*

Scale Back of PPL Proposed RR to % of Original Request:	65%	
Target Total Revenue Requriement Increase =	48,927	7.7%
Total Return at Scaled Back RR =	155,958	
System Average ROR at Scaled Back RR =	7.72%	

This Table assumes that the Revenue Requirement increase request by PPL is reduced by 35% in this proceeding.
Source: Exhibit JMK-2A Revised DOE Refund Adjusted.
Columns 2 through 7 were taken from Exhibit JMK-2A Revised DOE Refund Adjusted; values in the remaining columns are derived.
Column 9: The RROR is set at 1.25 for all classes (except for ISA) having a RROR of greater than 1.25 at present rates; *the RROR for the residential class is derived after all other class* RROR's are fixed by either the maximum increase percentage or the RROR cap of 1.25 (except the ISA class)
Class ISA revenues are set by a Special Agreement and are unaffected by the revenue allocations; the RR increase is set equal to the PPL proposed RR increase.
Column 13: The increase to the RTS, LP-6, and SL/AL Classes are held to 26% to avoid "rate shock."
RR = Revenue Requirements; RROR = relative rate of return, i.e. the class return percentage divided by the system average return percentage.

ATTACHMENT 1

O. G. Kasper
J. M. Kleha

PPL Electric Utilities Corporation
Response to Interrogatories of the
U.S. Department of Defense, Set II,
Dated August 1, 2007
Docket No. R-00072155

Q.2-1. Please provide a schedule which shows the results of revising Exhibit JMK 2A-Revised to exclude the effect of the DOE Refund from present rate revenue before allocating the proposed revenue increase.

A.2-1. Attachment 1 provides the requested information. Specifically, the attachment shows the effect of eliminating the DOE Refund from present tariff rate revenue before applying the Company's proposed revenue allocation principles of moving each rate class one-half of the way to the system average return, with the constraint that no rate class receive an increase of more than twice the system average revenue increase. These calculations are provided for informational purposes only and do not reflect a change in the Company's position as set forth in Exhibit JMK 2A-Revised.

PPL Electric Utilities
2007 Distribution Rate Filing
Comparison - JMK 2A-Revised to JMK 2A-Revised - Adjusted Present Revenues - DOE Refund
($000s)

	System	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
Present Tariff Revenues															
JMK 2A Revised	631,657	386,480	3,991	73,866	109,784	29,104	1,781	1,168	564	36	333	538	6,459	17,518	35
DOE Refund Adjustment	1,708	628	18	89	397	266	16	146	92	17	3	15	16	5	0
Adjusted Present Revenues	633,365	387,108	4,009	73,955	110,181	29,370	1,797	1,314	656	53	336	553	6,475	17,523	35
Proposed Revenue Increase															
JMK 2A Revised	76,980	72,507	999	198	(932)	(339)	(125)	5	(89)	[illegible]	(7)	0	541	4,213	0
JMK 2A Revised DOE Refund Adjusted	75,272	71,191	1,002	66	(1,186)	(424)	(131)	(41)	(118)	[illegible]	(9)	0	526	4,381	2
Change	(1,708)	(1,316)	3	(132)	(254)	(85)	(6)	(46)	(29)	4	(2)	0	(15)	168	2
Pct Increase - D Revs	11.88%	18.39%	24.99%	0.09%	-1.08%	-1.44%	-7.29%	-3.12%	-17.99%	24.53%	-2.68%	0.00%	8.12%	25.00%	5.71%
Total Revenue Increase Required	76,980	71,819	1,020	155	(789)	(158)	(115)	105	(26)	30	(6)	15	542	4,386	2
Overall Change from JMK 2A-Revised	0	(688)	21	(43)	143	[illegible]	[illegible]	[illegible]	63	21	1	15	1	173	2
Present Rate of Return															
JMK 2A Revised															
Return	128,371	55,214	(1,338)	22,823	37,454	10,102	688	376	245	(15)	117	283	1,742	672	8
ROR	6.35%	4.13%	-3.58%	12.60%	13.24%	13.37%	17.96%	12.25%	29.95%	-5.14%	14.29%	149.74%	8.42%	0.86%	8.51%
Pct of System ROR	100.00%	65.04%	-56.38%	198.43%	208.50%	210.55%	282.83%	192.91%	471.65%	-80.94%	225.04%	2358.11%	132.60%	13.54%	134.02%
JMK 2A Revised DOE Refund Adjusted															
Return	129,315	55,563	(1,328)	22,871	37,672	10,248	697	456	296	(5)	119	292	1,751	675	8
ROR	6.40%	4.16%	-3.55%	12.63%	13.32%	13.56%	18.20%	14.85%	36.19%	-1.71%	14.53%	154.50%	8.46%	0.86%	8.51%
Pct of System ROR	100.00%	65.00%	-55.47%	197.34%	208.13%	211.88%	284.38%	232.03%	565.47%	-26.72%	227.03%	2414.06%	132.19%	13.44%	132.97%
Proposed Rate of Return															
JMK 2A Revised															
Return	170,304	94,737	(791)	22,908	36,919	9,912	619	379	197	(9)	114	283	2,039	2,989	8
ROR	8.43%	7.09%	-2.11%	12.65%	13.05%	13.12%	16.16%	12.35%	24.08%	-3.08%	13.92%	149.74%	9.85%	3.83%	8.51%
Pct of System ROR	100.00%	84.10%	-25.03%	150.06%	154.80%	155.63%	191.70%	146.50%	285.65%	-36.54%	165.12%	1776.28%	116.84%	45.43%	100.95%
JMK 2A Revised DOE Refund Adjusted															
Return	170,304	94,361	(779)	22,884	36,998	10,012	624	433	231	2	114	292	2,039	3,084	9
ROR	8.43%	7.07%	-2.08%	12.64%	13.08%	13.25%	16.29%	14.10%	28.24%	0.68%	13.92%	154.50%	9.85%	3.95%	9.57%
Pct of System ROR	100.00%	83.87%	-24.67%	149.94%	155.16%	157.18%	193.24%	167.26%	334.99%	8.07%	165.12%	1832.74%	116.84%	46.86%	113.52%
Revenue Increase - Process Steps															
Increase	75,272														
Pct of D Revs	11.88%														
Uniform Increase - *System Pct*	75,272	46,046	477	8,797	13,106	3,494	214	156	78	6	40	0	770	2,084	4
50% Move to System ROR	0	28,902	3,822	(11,272)	(19,114)	(5,273)	(447)	(256)	(245)	24	(65)	0	(392)	4,316	(2)
25% Cap Adjustment - RTS & LP-6	0	3,297	(3,297)				8	6	3	(17)					0
50% Move to % of System ROR	0	(8,413)		2,321	4,499	1,269	89	49	44		15		127		0
25% Cap Adjustment - SL/AL	0	1,359	-	220	323	86	5	4	2	-	1	-	21	(2,021)	-
Final Revenue Increase	75,272	71,191	1,002	66	(1,186)	(424)	(131)	(41)	(118)	13	(9)	0	526	4,381	2

PPL Electric Utilities Corporation
2007 Distribution Rate Filing
ROR & Revenue Requirements
($000s)

OGK FIGURE 1 REVISED

JMK 2A-Revised - Adjusted Present Revenues - DOE Refund

	System	RS	RTS	GS-1	GS-3	LP-4	ISP	GH	SL/AL	LP-5	IST	LP-6	LPEP	L5-S
Present ROR	6.40%	4.16%	-3.55%	12.63%	13.32%	13.56%	18.20%	8.46%	0.86%	14.85%	36.19%	-1.71%	14.53%	8.51%
Pct of System	100.00%	65.00%	-55.47%	197.34%	208.13%	211.88%	284.38%	132.19%	13.44%	232.03%	565.47%	-26.72%	227.03%	132.97%
Proposed ROR	8.43%	7.07%	-2.08%	12.64%	13.08%	13.25%	16.29%	9.85%	3.95%	14.10%	28.24%	0.68%	13.92%	9.57%
Pct of System	100.00%	83.87%	-24.67%	149.94%	155.16%	157.18%	193.24%	116.84%	46.86%	167.26%	334.99%	8.07%	165.12%	113.52%
Change Proposed ROR	2.03%	2.91%	1.47%	0.01%	-0.24%	-0.31%	-1.91%	1.39%	3.09%	-0.75%	-7.95%	2.39%	-0.61%	1.06%
Pct of System	0.00%	18.87%	30.80%	-47.40%	-52.97%	-54.70%	-91.14%	-15.35%	33.42%	-64.77%	-230.48%	34.79%	-61.91%	-19.45%
Revenue Increase	75,272	71,191	1,002	66	(1,186)	(424)	(131)	526	4,381	(41)	(118)	13	(9)	2
Pct of Total Revenues	2.41%	5.38%	3.70%	0.03%	-0.16%	-0.11%	-0.65%	1.53%	17.75%	-0.02%	-0.14%	0.05%	-0.16%	0.19%
Pct of Distribution Rate Revenues	11.89%	18.39%	24.99%	0.09%	-1.08%	-1.44%	-7.29%	8.12%	25.00%	-3.12%	-17.99%	24.53%	-2.68%	5.71%
25% Pct Incr Cap	25.00%													
Pct of System														
50% Move to SARR														
Present		65.00%	-55.47%	197.34%	208.13%	211.88%	284.38%	132.19%	13.44%	232.03%	565.47%	-26.72%	227.03%	132.97%
Proposed		83.87%	-24.67%	149.94%	155.16%	157.18%	193.24%	116.84%	46.86%	167.26%	334.99%	8.07%	165.12%	113.52%
Move		18.87%	30.80%	-47.40%	-52.97%	-54.70%	-91.14%	-15.35%	33.42%	-64.77%	-230.48%	34.79%	-61.91%	-19.45%
Pct Move		53.91%	19.81%	48.70%	48.99%	48.89%	49.43%	47.69%	38.61%	49.06%	49.52%	27.45%	48.74%	58.99%

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF SMALL BUSINESS ADVOCATE
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, Pennsylvania 17101

William R. Lloyd, Jr.
Small Business Advocate

(717) 783-2525
(717) 783-2831 (FAX)

2007 SEP 10 PM 1:19

August 17, 2007

OVERNIGHT DELIVERY

Mr. John Kelly
Commonwealth Reporting Company, Inc.
700 Lisburn Road
Camp Hill, PA 17011

Re: Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation
Docket No. R-00072155

Dear Mr. Kelly:

Enclosed please find the original, signed Affidavit of Robert D. Knecht, for inclusion into the record, at the above-captioned proceeding.

If you have any questions, please feel free to contact me.

Sincerely,

Steven C Gray

Steven C. Gray
Assistant Small Business Advocate
Attorney ID No. 77538

DOCUMENT FOLDER

Enclosure

DOCKETED
SEP 11 2007

8-16-07
R-00072155
Hby
JAK

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ORIGINAL

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	DOCKET NO. R-00072155
PPL ELECTRIC UTILITIES CORPORATION	:	

AFFIDAVIT OF ROBERT D. KNECHT

I, Robert D. Knecht, being duly sworn according to law, depose and say that I am employed as a consultant by the Pennsylvania Office of Small Business Advocate, having qualifications as set forth in Exhibit IEc-1 of my Direct Testimony at OSBA Statement No. 1 and have been authorized to make this affidavit on its behalf and that the facts set forth in my Direct Testimony, Rebuttal Testimony, and Surrebuttal Testimony, OSBA Statements 1 through 3, are true and correct to the best of my knowledge, information, and belief and expect to be able to prove the same at any hearing hereof.

Robert D. Knecht

Sworn and subscribed before me
this 15 day of August 2007.

Signature of official administering oath

My Commission expires: 1/3/08

ELIZABETH BORKOWSKI
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS

OSBA STATEMENT NO. 1

Hby DK

AUG 1 8 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-00072155
PPL ELECTRIC UTILITIES CORPORATION	:	

DOCUMENT FOLDER

Direct Testimony and Exhibits of

ROBERT D. KNECHT

DOCKETED
SEP 7 - 2007

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Distribution Cost Allocation Methodology
Distribution Revenue Allocation
Commercial Classes Rate Design
Energy Efficiency Rider

Date Served: July 6, 2007

Date Submitted for the Record: ____________________

RECEIVED
AUG 1 7 2007
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

DIRECT TESTIMONY OF ROBERT D. KNECHT

1 Introduction and Overview

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal and the Treasurer of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. As part of my consulting practice, I have prepared analyses and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and an M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. I am appearing in these proceedings on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My résumé and a listing of expert testimony that I have filed in utility regulatory proceedings are attached in Exhibit IEc-1.

Q. What is the purpose of this testimony?

A. This testimony presents my evaluation of the cost allocation, revenue allocation and commercial class rate design proposals of PPL Electric Utilities Corporation ("PPL" or "the Company") in this proceeding.

Q. PPL recently submitted supplemental direct testimony with revised cost of service study analyses. What is your understanding of the current status of the Company's proposal?

A. In its original filing, PPL submitted a cost of service study ("COSS") analysis at current rates, where "current rates" were defined as the rates that were in effect as of the compliance filing in PPL's 2004 base rates case, Docket No. R-00049255. For convenience, I will refer to those rates as "current compliance rates." PPL also submitted a revenue allocation approach that assigned the proposed rate increase of $83.0 million among the various rate classes (including some rate decreases). In addition, PPL developed a rate design proposal for each rate class to recover the $83.0 million increase.[1]

Subsequent to PPL's original filing, the parties to the remand phase of PPL's 2004 base rate case reached a settlement. If that settlement is approved, it will implicitly change the "current rates" starting point for this proceeding. In recognition of that, PPL submitted supplemental direct testimony and Exhibit JMK-2A, which provided the results of a revised COSS analysis at "current settlement rates" and at proposed rates.

In preparing its COSS analysis at proposed rates in Exhibit JMK-2A, PPL set each class's rate increase at the same dollar increase proposed in its original filing.[2] Thus, for example, for Rate RS, PPL originally proposed a revenue increase of $77.3 million. That represented a 20.5 percent increase over the "current compliance rates" of $376.7 million for Rate RS. In Exhibit JMK-2A, PPL assigns a $77.3 million increase to Rate RS, which represents a 20.0 percent increase over "current settlement rates" of $386.5 million.

PPL has not submitted a specific proposal regarding the rate design for each rate class regarding this change. Moreover, Mr. Kleha's supplemental direct testimony indicates that PPL is continuing to review its revenue allocation to determine whether it remains appropriate, and may offer a revised proposal in the rebuttal phase of this proceeding.

Rather than confuse the issue by working from two different starting points, I have relied upon PPL's updated filing ("current settlement rates") as the starting point for my evaluation.

[1] PPL's overall proposed revenue increase is $83.5 million, of which $83.0 million relates to rate revenues and approximately $0.5 million relates to annualization adjustments, late payment revenues, and STAS changes. See Exhibit Future 1 D3. However, the 2007 distribution revenues shown in the 2007 proof of revenues provided in response to OTS-RE-43-D are at least $16 million higher than those shown in Exhibit Future 1 D3. Moreover, that response indicates that the proposed rates will produce a rate increase of $84.7 million. Once certain pending discovery responses are received and PPL files its promised rebuttal testimony regarding revenue allocation, I will address this discrepancy in my surrebuttal testimony as necessary.

[2] The system-wide rate of return shown in Exhibit JMK-2A at proposed rates is 8.39 percent, slightly above the 8.36 percent cost of capital claimed at Exhibit Future 1 B-9 (and reported in the original Exhibit JMK-2). I assume that PPL will make adjustments to its proposed revenues in its rebuttal testimony to reconcile this discrepancy.

Q. Please summarize the conclusions from your analysis.

A. In summary, my conclusions are as follows:

- PPL's COSS provides a reasonable cost basis for allocating revenue and setting rates in this proceeding. It is reasonably consistent with the Commission-approved methodology that PPL has used for many years. In addition, PPL has adjusted its COSS to recognize the most credible economic complaint lodged against it in prior rate proceedings.

- If PPL's full proposed rate increase is granted, PPL's proposed allocation of the revenue increase will generally result in reasonable progress toward cost-based rates for the major distribution voltage rate classes. However, the amount of progress will be somewhat less than that claimed by PPL. Furthermore, in light of the rate reductions already given to some classes in the remand settlement, PPL's proposed rate changes for Rates LP-5, LP-6 and L5-S in this proceeding should be modified.

- If the Commission reduces PPL's proposed rate increase, the "proportional scaleback mechanism" traditionally used by the Commission cannot be adopted, because it will substantially reduce the progress toward cost-based rates that is inherent in PPL's proposal. The proportional scaleback mechanism will also produce illogical results for those rate classes which are assigned rate decreases. Therefore, rather than apply the proportional scaleback mechanism, I recommend a two-step approach. *First*, first-dollar relief should be provided to Rate Class GS-1, in recognition of the relatively limited progress for GS-1 inherent in PPL's revenue allocation proposal. *Second*, any further reductions should be shared among the rate classes using the "differential scaleback mechanism." Under the differential scaleback mechanism, for example, if the Commission reduces PPL's proposed increase from 13.1 percent to 10.1 percent, each class's proposed percentage rate change is lowered by 3.0 percent (13.1 percent minus 10.1 percent).

- If PPL's COSS methodology is approved, PPL's rate design proposals for the commercial rate classes (rate classes GS-1, GS-3, and GH) are generally reasonable. However, PPL should conduct an evaluation as to whether each Rate GH-1 customer would face lower rates under the proposed Rate GH-1 or Rate GS-3. PPL should then advise GH-1 customers to switch to GS-3 if they would pay lower rates.
- If the Commission approves PPL's proposed demand-side management funding proposals, it should modify the proposed Energy Efficiency Rider ("EER") to put a cap on the overall amount of costs that PPL may recover from the rider. The Commission should also modify the reconciliation mechanism to be class-specific, i.e., to recover from each class only what was spent on behalf of that class.

2 <u>PPL's Cost of Service Study</u>

Q. In your view, what are the key issues involved in PPL's COSS in this proceeding?

A. **<u>First</u>**: This is a distribution rates proceeding. Therefore, PPL submitted a COSS for its distribution costs only. Because large industrial customers tend to take service at either transmission voltage or at primary distribution service voltage, *the vast majority of distribution costs are related to residential, commercial, and lighting customers.* While industrial customers represent almost one-third of PPL's kWh deliveries, they are responsible for less than 5 percent of PPL's distribution costs.

Table IEc-1 below compares the share of distribution costs and revenues for the major customer groupings.

Table IEc-1 Rate Class Group Share of Distribution Costs and Revenues		
	Share of Costs	*Share of Revenues*
Residential	70%	66%
Commercial	22%	27%
Industrial	4%	5%
Lighting	4%	3%
Total	**100%**	**100%**
Source: Derived from Exhibit JMK-2A, costs and revenues at proposed rates.		

Second: The cost allocation methodology presented in PPL's COSS in this proceeding is consistent with the methodology that PPL has used for many years. Consistent with Pennsylvania practice, the PPL COSS is an "embedded cost" study, meaning that it allocates each component of PPL's revenue requirement to the various rate classes, based on an assessment of the cost causation factor for that cost item. Because the revenue requirement is based on the historical cost of investments, this approach is referred to as an "embedded cost" approach.[3]

Based on my experience in PPL's base rates proceedings in 1995 and 2004, the key disputed issue affecting distribution cost allocation is the "classification" of distribution plant and related O&M costs.[4] Historically, PPL has followed the practice of classifying its primary distribution system as 100 percent demand-related, and classifying its secondary distribution system as partly demand-related and partly customer-related. That

[3] Rather than relying on embedded cost studies, some jurisdictions rely on marginal cost studies, wherein the costs for each rate class are based on the cost to provide an incremental unit of demand, and to provide service to an additional customer. Rather than being based on the historical cost of the entire system, marginal cost studies tend to be based on the replacement value of equipment needed to meet incremental load. Marginal cost studies require a "true-up" mechanism to reconcile marginal costs with the utility's revenue requirement.

[4] In cost allocation study jargon, "classification" relates to identifying what general cost causation factor applies to a particular cost item. Typically, the classification categories are demand, energy, and customer. "Allocation" refers to the arithmetic distribution of the classified costs among the various rate classes. For example, a cost item that is classified as demand-related will be allocated among the rate classes in proportion to each class's contribution to some measure of peak demand.

method has been explicitly approved by the Commission.[5] Other parties have contended that distribution plant is not causally related to the number of customers, and they have offered alternative classification approaches based on a combination of peak demand and annual energy consumption.

To classify its secondary distribution costs, PPL uses a "minimum system" approach, which is one of the industry standard methods.[6] In the minimum system approach, the customer component of costs is set at the cost of the smallest piece of equipment that is currently being installed on the system. For example, the customer component of transformers is set at the cost of installing the minimum-sized transformer at all locations on the system, rather than at the cost of the actual mix of transformers. The balance of the costs above the cost of the minimum system are then deemed to be demand-related.

However, PPL's approach is sometimes criticized for the reason that the "minimum system" retains some load-carrying capability, meaning that some demand-related costs are implicitly included in the customer component. (With Mr. Ewen of IEc, I made this argument in PPL's 2004 base rates proceeding.[7]) In this proceeding, PPL has attempted to address that concern by developing a "no-load adjustment factor," which adjusts the minimum system customer component downward to reflect the load carrying capability of the minimum system.

Q. In your opinion, does PPL's proposed classification of distribution costs in Exhibit JMK-2A provide a reasonable cost basis for setting rates in this proceeding?

A. Yes it does. Distribution plant must be built to accomplish the dual objectives of (a) interconnecting all of the customers on the system and (b) providing power to customers during periods of peak demand. Therefore, distribution plant costs are causally related to both the number of customers and customer peak demands. Moreover, classifying costs

[5] See Recommended Decision, Docket No. R-00943271C001-C0145, ALJ Robert A. Christiansen, page 208; and, Opinion and Order, Docket No. R-00942371C001-C0145, Pennsylvania Public Utility Commission, page 197.

[6] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January 1992, pages 90-92.

[7] OSBA Statement No. 1, Docket No. R-00049255, June 29, 2004, pages 15-16.

into both demand and customer components recognizes the cost economies of serving larger customers. That is, because it generally takes more poles, more transformers, and more feet of conductor to provide service to one hundred 5-kW customers than it does to provide service to five 100-kW customers, it is more costly per unit of demand to serve smaller customers.

In addition, in this proceeding, PPL has made an effort to recognize that the minimum system approach used in the past tended to overstate the customer component of secondary distribution costs. PPL addressed this issue by adopting a no-load adjustment factor approach. Although I recommended that PPL use an alternative classification approach in the last proceeding (namely the "zero-intercept" approach, another industry standard method), it is my understanding that PPL does not have the detailed data with which to perform such a study. Since the preferred approach is not available, I consider PPL's adjustment in this case to be reasonable.

Finally, PPL's methodology implicitly recognizes that some analysts do not believe that distribution plant costs have a customer component at all. The standard application of either the minimum system or the zero-intercept methodology requires that both primary voltage and secondary voltage distribution costs be split into demand and customer components.[8] However, PPL treats all primary voltage assets as demand-related, and uses the classification split only for secondary assets. In effect, PPL employs a hybrid methodology.

Q. What are the implications of PPL's COSS for revenue allocation in this proceeding?

A. For the major distribution voltage rate classes, PPL's COSS shows that, relative to the other rate classes, the residential and street lighting classes are under-recovering allocated costs at current settlement rates, while the commercial and industrial rate

[8] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January 1992, page 93.

classes are over-recovering allocated costs.[9]

I base this conclusion on the following cost performance metrics:

- Class Rate of Return: Class rate of return is measured by taking a class's revenues at current settlement rates; subtracting that class's operating, depreciation, and tax costs to produce class net income; and then dividing class net income by the allocated class rate base. If a class's rate of return is below the system average rate of return, the class is said to be under-recovering allocated costs, in comparison to the other rate classes. Conversely, if a class's rate of return is above the system average, the class is considered to be over-recovering allocated costs, relative to the other rate classes.

- Indexed Rate of Return: The indexed rate of return represents the ratio of a class's rate of return to the system average rate of return. If the ratio exceeds 100 percent, the class is deemed to be over-recovering allocated costs on a relative basis. On the other hand, if the ratio is less than 100 percent, the class is deemed to be under-recovering allocated costs on a relative basis.

- Dollar Subsidies: Dollar subsidies for each rate class are calculated as the *difference* between class revenues and all costs allocated to that class, including the cost of capital (i.e., return on rate base).[10] When performed at current settlement rates, the cost of capital is set at the actual return achieved by the

[9] In the revenue allocation phase of a rate proceeding, it is important to recognize that over- or under-recovery of allocated costs is measured on a *relative* basis, rather than on an absolute basis. For example, a rate class may exhibit a class rate of return of 7.5 percent at current rates, compared to a system average rate of return of 6.1 percent. That class is said to have revenues that over-recover allocated costs, because the evaluation is made on a relative basis. That finding implies that the class should be assigned a below system average rate increase. However, if the utility has a claimed rate of return of 8.4 percent, the class might be thought of as under-recovering fully allocated costs on an *absolute* basis, because its rate of return is only 7.5 percent. It would therefore need to be assigned some rate increase to get its proposed revenues into line with allocated costs (albeit an increase that is a lower percentage than the system average increase). Nevertheless, it is normal practice (and less confusing) to make the cost performance comparisons at current rates on a relative basis.

[10] The dollar subsidy approach is arithmetically very similar to the rate of return differential approach. In the rate of return differential method, relative class cost performance is measured as the difference between the class rate of return and the system average rate of return. Because the differential rate of return approach measures progress toward cost-based rates that is identical to the dollar subsidy approach, I report only the latter in this testimony.

utility at current settlement rates. A positive value indicates that a class is over-recovering allocated costs; a negative value indicates cost under-recovery.

- Revenue-Cost Ratio: The revenue-cost ratio is measured as the *ratio* of class revenues to all costs allocated to that class, including the cost of capital. When performed at current settlement rates, it is "normalized" such that the system-wide average is 100 percent. A revenue-cost ratio above 100 percent indicates that a class is over-recovering allocated costs. A revenue-cost ratio below 100 percent indicates that a class is under-recovering allocated costs.

The results for each of these metrics for the major distribution rate classes are shown in Table IEc-2 below. Bold-faced numbers indicate that the metric shows that a class is under-recovering allocated costs.

Table IEc-2
Subsidy Metrics for PPL Distribution Costs
At Current Compliance Rates

	Class RoR	*Indexed RoR*	*Dollar Subsidy ($mm)*	*Revenue-Cost Ratio*
RS	**4.1%**	66%	**($50.2)**	**90%**
RTS	**-3.9%**	**-63%**	**($ 7.1)**	**39%**
GS-1	12.6%	205%	$21.3	137%
GS-3	12.0%	195%	$32.1	135%
LP-4	12.8%	208%	$ 9.2	141%
GH	7.6%	123%	$ 0.6	107%
SL/AL	**0.6%**	**9%**	**($8.0)**	**70%**
Total	6.1%	100%	$0	100%

Source: Exhibit IEc-2, Schedule A
Note that "Total" includes the ISP, LP-5, IST, L-6, LPEP, ISA, and L5-S classes, although these classes have very little impact on distribution costs and revenues.

Under every metric reported, Rates RS, RTS, and SL/AL (Lighting) under-recover allocated costs. On the other hand, under every metric reported, Rates GS-1, GS-3, LP-4, and GH over-recover allocated costs.

3. **Revenue Allocation**

Q. What are the common criteria used by utilities and regulators to determine the appropriate level of revenue that each rate class should contribute at proposed rates?

A. In my experience, the key criteria are: Cost, Gradualism, and Value of Service.

The **Cost** criterion implies that it is desirable that class revenues at proposed rates are moved more into line with allocated costs than they are at current rates, i.e., that the revenue allocation proposal results in progress toward cost-based rates. Generally, this criterion implies that rate classes that are under-recovering costs at current rates receive a higher than system average rate increase, while rate classes that are over-recovering costs receive below-system-average increases.

The **Gradualism**, or "avoidance of rate shock," criterion serves as a judgmental brake on the cost criterion, in that it seeks to avoid excessive rate increases for any particular rate class in the interests of rate stability. The gradualism criterion necessarily conflicts with the principle of fairness (or equity), in that it allows utilities to over-recover costs from particular rate classes, often for very long periods of time.

The **Value of Service** criterion can be used by regulators to set lower rates for those classes which assign less value to the utility's service than for those classes which value the service more highly. In practice, value of service is often a euphemism for the market power of the utility with respect to serving a particular rate class or customer. Those rate classes which have few options to utility service (i.e., they have what economists call a "low price elasticity of demand") are deemed to value the service more highly. Those classes which have competitive options (such as relocating the business, closing down, or expanding the business elsewhere) are deemed to ascribe less value to the service. Thus, under this criterion, regulators will sometimes permit rates to be set below fully allocated costs for a customer the utility would otherwise lose. In so doing, the regulator may keep rates lower for all customers, because the utility retains at least some margin from the competitive customer who would otherwise leave the system.

Q. How does PPL reflect these criteria in its revenue allocation proposal?

A. With respect to costs, PPL indicates that it would generally like to move rates into line with allocated costs in three base rates proceeding, with this case being the second. To that end, PPL developed a revenue allocation proposal that moved the indexed rate of return for each class at current compliance rates about halfway toward 100 percent at proposed rates. For example, for Rate Class GS-1, PPL's indexed rate of return at current compliance rates was 214 percent. Under PPL's proposed rates, the GS-1 class's indexed rate of return dropped to 159 percent. Based on this metric, the class progress toward cost-based rates is 48 percent. (Progress is measured by the change in class indexed rate of return from actual to proposed rates divided by the change in class indexed rate of return needed to get to cost-based rates. For GS-1, that calculation is (214% - 159%)/(214% - 100%) = 48%.)

PPL also applies the criterion of gradualism, by limiting the overall rate of increase for any particular rate class to two-times the system average increase. This limit constrains the rate increases for Rates RTS and the lighting ("SL/AL") classes. While there is no definitive standard for gradualism, the "two-times rule" applied by PPL is a relatively common rule-of-thumb.

Finally, because most of PPL's distribution voltage customers have few competitive alternatives to distribution service, and the distribution costs represent only a very small portion of most large industrial customers' bills, the value of service principle has little relevance for PPL in this proceeding.

Q. Do you have any concerns about PPL's revenue allocation?

A. PPL's proposal to move rates significantly more closely into line with allocated costs is reasonable and appropriate, as is PPL's philosophy to bring rates into line with allocated costs over three rate proceedings. Unfortunately, the indexed rate of return metric used by PPL to evaluate progress toward cost-based rates tends to overstate the actual progress being made.[11] In addition, with the switch from *current compliance rates* to *current settlement rates* as the starting point, the measure of progress toward cost-based rates veers away from PPL's original intent.

Table IEc-3 shows the progress toward cost-based rates under PPL's revenue allocation proposal (as calculated by the three alternative metrics) with the current settlement rates, rather than the current compliance rates, as the starting point.

Table IEc-3
Progress Toward Cost-Based Rates
PPL Revenue Allocation Proposal Relative to Current Settlement Rates

	Indexed RoR	*Dollar Subsidy ($000)*	*Revenue-Cost Ratio*
RS	60%	46%	49%
RTS	20%	- 9%	5%
GS-1	50%	31%	38%
GS-3	54%	37%	40%
LP-4	55%	38%	42%
GH	72%	62%	58%
SL/AL	34%	10%	19%

Source: Exhibit IEc-2, Schedule A

As Table IEc-3 demonstrates, the progress toward cost-based rates under either the dollar subsidy method or the revenue-cost ratio method is substantially less than 50 percent for the GS-1, GS-3, and LP-4 rate classes. ***This result means that PPL will have to make significantly more progress in the third base rates case*** than the Company has assumed, or it will not be able to meet its goal of achieving cost-based rates in that proceeding.

Of the three metrics, I consider the revenue-cost ratio metric to be the best, because it generally indicates that if a class receives a system-average ("neutral") rate increase, its revenue-cost ratio will stay approximately the same at present and proposed rates. Under the indexed rate of return metric, a neutral rate increase will tend to move the class

[11] In fact, as I demonstrated in the remand phase of PPL's 2004 base rates case, the indexed rate of return can indicate that a revenue allocation proposal is making progress toward cost-based rates when it does not. That complaint does not apply to PPL's proposal in this proceeding.

indexed rates of return toward unity (indicating progress when there is none). Conversely, the dollar subsidy approach will indicate that a neutral rate increase results in the subsidies getting larger (implying that rates are moving away from allocated costs despite a neutral rate increase). Note that Table IEc-3 shows that progress under the revenue-cost ratio metric lies between the other two metrics' results for most rate classes.

Q. In light of the results shown in Table IEc-3 and Exhibit IEc-2, Schedule A, what do you propose for the revenue allocation at PPL's full proposed rate increase?

A. Regarding the major distribution rate classes, I could perhaps quibble with PPL's proposed revenue allocation, in that it does not make sufficient progress toward cost-based rates for the GS-1, GS-3 and LP-4 rate classes. However, I recognize that the rate increases for Rates RTS and SL/AL are constrained by gradualism. I also recognize that PPL's proposal will move Rate RS approximately halfway toward cost-based rates, using the revenue-cost ratio metric. In that context, it would be difficult to make significantly more progress for the commercial and industrial classes.

Thus, at the full revenue requirement, I deem PPL's revenue allocation proposal to be reasonable for the major classes.

Regarding the other rate classes, however, Exhibit IEc-2 Schedule A shows that Rates LP-6 and L5-S are under-recovering costs at current settlement rates. Therefore, a rate decrease (or a below system-average increase) is not appropriate for those classes. (In effect, the remand settlement already applied the rate relief for those classes that PPL originally intended to apply in this proceeding.)

Similarly, PPL's proposal would result in rates for LP-5 customers moving fully into line with allocated cost, which is likely to be perceived as inequitable by the other rate classes that make much less progress.

I therefore propose the following revenue-neutral adjustments to PPL's proposed revenue allocation:

- Rather than apply a rate decrease of $131,000 to Rate LP-5, set the revenue increase for that class at $0.

- Rather than apply a rate decrease of $8,000 to Rate LP-6, assign a rate increase of $12,000.

- Rather than apply a rate increase of $4,000 to L5-S, apply a rate increase of $12,000.

- Credit $159,000 to the GS-1 rate class, because GS-1 makes the least progress toward cost-based rates of all the major distribution rate classes.

Q. **If the Commission awards a smaller rate increase than that proposed by PPL, would you recommend that the Commission use a proportional scaleback mechanism to reduce each class's proposed rate increase?**

A. No I would not. The traditional "proportional scaleback mechanism" fails for two reasons.

<u>**First**</u>: PPL proposes rate decreases for some industrial rate classes. Under the arithmetic of the proportional scaleback mechanism, the customers in these classes would pay *higher* rates if the Commission *reduces* PPL's allowed revenue requirement than if the Commission approves the full proposed increase.

For example, PPL proposes to assign Rate LP-4 customers a $353,000 rate decrease with a system-wide increase of $83.0 million. If the Commission reduces the $83.0 million increase by 20 percent to $66.4 million, the rate decrease for LP-4 will be reduced to $282,000. In effect, taking $16.6 million out of PPL's rate increase will cause LP-4 rates to *rise* by some $71,000 under the proportional scaleback mechanism. This effect would put LP-4 customers in the awkward position of benefiting by *opposing* any reductions to the proposed rate increase. Thus, the proportional scaleback mechanism cannot reasonably apply to these customers.

Second: More importantly, however, the proportional scaleback mechanism significantly reduces the progress toward cost-based rates that is inherent in the full requirements proposal.

For example, at the full revenue requirement, the GS-3 class's progress toward cost-based rates is 40 percent under the revenue-cost ratio metric. However, if PPL's proposed rate increase is reduced by 20 percent, the GS-3 class's progress toward cost-based rates falls to 32 percent. Thus, applying the proportional scaleback mechanism is inconsistent with PPL's stated goal of moving rates into line with allocated costs in three base rates proceedings.

Q. What do you propose as an alternative to the proportional scaleback mechanism?

A. I propose a two-step adjustment.

First: I recommend that the Commission adopt a "first dollar relief" proposal for the GS-1 rate class. Specifically, I propose that the GS-1 rate increase be reduced to zero. Under PPL's full requirements proposal, the GS-1 rate increase is about $828,000. After the large industrial rate class adjustments I propose above, that amount is reduced to $669,000. Thus, I recommend that the first $669,000 in an overall rate reduction be applied to Rate GS-1.[12]

By way of explanation, as shown in Exhibit IEc-2 Schedule A, PPL's proposed revenue allocation results in less progress toward cost-based rates for the GS-1 class than for any other major distribution rate class, as calculated under any metric. In fact, while not all parties agree with PPL's cost allocation methodology, ***every*** COSS filed in PPL's 2004 base rates proceeding, and, as far as I have been able to determine, ***every*** alternative COSS filed by PPL in response to interrogatories in this proceeding, indicates that the GS-1 class currently provides revenues in excess of allocated cost. This statement is not true for any other rate class.

[12] If the Commission does not approve my proposed adjustments for the LP-5, LP-6 and L5S classes, I recommend that the first $828,000 in an overall rate reduction be applied to Rate GS-1.

Second: I recommend that the Commission apply any further reduction in the overall revenue increase using the "differential scaleback mechanism." In this approach, the same percentage adjustment to the rate increase (or rate decrease) is applied to every rate class.

For example, if the Commission reduces the overall proposed increase by 3.0 percentage points (from, say, 13.1 to 10.1 percent), each class's revenue allocation at the full revenue requirement is scaled back by 3.0 percent of that class's current rates. Thus, for example, a class that was assigned an 18.2 percent increase at the full proposed revenue requirement would receive a 15.2 percent increase under the reduced revenue requirement. Similarly, a class that was assigned a 7.4 percent increase at the full proposed revenue requirement would be assigned a scaled back 4.4 percent increase. In addition, a class that was assigned a 1.0 percent increase at the full proposed revenue requirement would be assigned a scaled back 2.0 percent *decrease*.

Q. Can you provide a specific example of how your adjustments would work?

A. An example is attached in Exhibit IEc-2, Schedule B. For the reasons explained above, PPL's full requirements increases for the LP-5, LP-6 and L5-S classes shown in that example are first adjusted to reflect my proposed changes to PPL's original proposal for the effects of the remand settlement. This results in a reduction of $159,000 for the GS-1 class and an increase of $159,000 for LP-5, LP-6 and L5-S. This adjustment has ***no*** impact on the overall revenue requirement and is made if PPL is awarded the entire revenue increase it has requested or if PPL is awarded less than the full requirement.

To demonstrate the effects of a scaleback, the example in Exhibit IEc-2, Schedule B is based on the assumption that the Commission awards PPL a 10.7 percent return on equity, rather than its proposed return of 11.5 percent. That change reduces PPL's target rate of return on rate base from 8.39 percent (in Exhibit JMK-2A) to 8.02 percent. To achieve this rate of return, I estimate that PPL's proposed revenues should decline by approximately $13.59 million.

Under my proposal, the $13.59 million is allocated among the various rate classes through the following steps:

1. The first $0.67 million of the $13.59 million is assigned to the GS-1 rate class in order to get that rate class's rate increase to zero. This leaves a balance of $12.92 million to be allocated among all classes using the differential scaleback mechanism.

2. The $12.92 million represents 2.05 percent of current settlement rate revenues. Using the differential scaleback mechanism, the rate increase (in dollars) for each class is then reduced by an amount equal to 2.05 percent of that class's current settlement rate revenues.

A summary of the results of this analysis are shown in Table IEc-4 below, and in detail in Exhibit IEc-2 Schedule B.

Table IEc-4
The Differential Scaleback Mechanism Example

	PPL Proposed Rate Increase	*IEc Scaled Back Increase*	*Progress Toward Cost-Based Rates*
RS	19.9%	17.8%	50%
RTS	23.7%	21.7%	5%
GS-1	1.1%	-2.0%	41%
GS-3	0.5%	-1.6%	40%
LP-4	-1.2%	-3.3%	42%
GH	8.5%	6.5%	56%
SL/AL	23.5%	21.4%	20%
Total	**13.1%**	**11.0%**	--

Source: Exhibit IEc-2, Schedule B
Notes: Progress is measured using the normalized revenue-cost ratio metric.
"Total" includes all rate classes, including unreported large industrial classes.

As Table IEc-4 shows, the differential scaleback mechanism, combined with my proposals for Rate GS-1, maintains the reasonable progress toward cost-based rates for the commercial and industrial rate classes that was inherent in PPL's original proposal.

4. Commercial Class Rate Design

Q. Please summarize PPL's approach to distribution tariff design for the commercial classes.

A. In general, PPL proposes to increase its customer and demand charges within all of the rate classes (to the extent practicable), and to reduce or eliminate energy charges. PPL's rationale for this proposal is that distribution costs are virtually all customer or demand-related, and should therefore be recovered from customer and demand charges. For the GS-1 class, this proposal takes the form of higher increases for the customer charge, the demand charge, and the first block energy charge.[13] For the GS-3 and GH classes, this proposal eliminates the energy charges and recovers all distribution costs with a demand charge.

Q. Do you have concerns about this methodology?

A. I generally agree that utility rates should be reasonably aligned with the classified costs that they are designed to recover. That is, demand charges should recover demand costs, energy charges should recover energy costs, and customer charges should recover customer costs. However, it is important to recognize that raising demand charges will have a disproportionate impact on low load factor customers.

Moreover, there is a theoretical reason to retain an energy component in distribution charges that are designed to recover demand costs. In PPL's COSS, distribution demand costs are allocated using a class non-coincident peak ("NCP") allocator. This NCP allocator measures the total demand for the class at the time when the overall class is at its peak demand level.

For example, commercial class non-coincident peaks usually occur in the summer, because these classes have relatively more air conditioning than heating load. PPL's residential classes's non-coincident peaks tend to occur in the winter. However, each individual customer within a class may not experience its own peak at the moment of the

[13] PPL's GS-1 tariff is blocked on a kWh per kW basis. That is, the kWh that are subject to the higher first block charge are proportionate to billing demand. In this specific case, the block size is 150 kWh per kW. Thus, except for extremely low load factor customers (below 20 percent), an increase in the first block charge is identical to a demand charge increase.

class peak. For example, some general service customers may be heating customers and experience winter peaks; therefore, their contribution to the class NCP is lower than their overall peak. In other words, the class NCP contains some demand *diversity*.

However, on a billing basis, each customer is billed for his full *undiversified* peak demand. For example, customers with very low load factors will tend to peak when the class is not peaking, and therefore will pay more than their share of the class NCP demand costs. By including an energy charge in the tariff design, the low load factor customers are more accurately charged for the costs that they cause.

Q. Do you propose any changes to PPL's tariff design philosophy for GS-1, GS-3 or GH customers?

A. Not in this proceeding. For the following reasons, I do not believe that PPL's proposals to modify the tariff cause any inappropriate impact on these customers:

- The GS-1 distribution tariff continues to recover over 11 percent of revenues in its tail block energy charge and some 44 percent of revenues in its first block energy charge. By doing that, PPL at least partly recognizes demand diversity. However, I do recommend that PPL prepare an analysis of demand diversity within the class before reducing the tail block energy component of billing charges further.

- The GS-3 distribution tariff already recovers most costs on a demand basis. Moreover, the evidence available does not suggest that there is significant diversity of demand in the GS-3 class. Average monthly billing demand for GS-3 customers is about 7 percent higher than class NCP demand. Thus, there is no pressing need to reflect demand diversity through the use of an energy charge for this class.

- PPL does not use billing demand "ratchets" for GS-3 customers. As such, if a low load factor customer experiences a high peak demand in a particular month, it will need to pay a demand charge for that peak only once, and will not continue to experience that charge for the whole year.

- The GH-1 and GH-2 rate classes have been closed to new customers since 1972. PPL's rate design proposal will facilitate the long-overdue phase-out of these rates.

Q. Do you have any other recommendations regarding the phase-out of the grandfathered GH rate classes?

A. As noted above, service under tariff GH-1 has been closed to new customers since 1972. The customers who take service under that schedule are commercial electric space heating customers. The average monthly electricity consumption for a GH-1 customer is similar to (albeit a little lower than) the average GS-3 customer. Further, like GS-3, service under GH-1 has a 25 kW billing demand minimum. At current compliance rates, almost half the distribution revenues are recovered from the demand charge. PPL proposes to adopt a 100 percent demand charge approach, which will parallel the proposed GS-3 distribution rate design. While this change may have a relatively large impact on the low load factor customers within the class, these customers are the electric heat customers who cause the class to attract a significant amount of demand-related distribution costs in the COSS.

Moreover, paralleling the GS-3 design has other advantages. I estimate that the average GS-3 generation charge (energy, capacity, CTC, ITC) is now about 6.8 cents per kWh, and the average GH-1 generation charge is very similar, at about 6.9 cents per kWh. Since the transmission rates for GS-3 and GH-1 are the same, the generation rates are similar, and the proposed distribution charge for GH-1 will be higher than that for GS-3, I would expect that a significant number of customers would benefit by migrating from GH-1 service to GS-3 service. I therefore recommend that the Commission direct PPL to prepare a customer-by-customer rate comparison under the proposed GH-1 and GS-3 tariff schedules, for each current GH-1 customer. Further, PPL should notify all GH-1 customers who could reduce their bills by switching to GS-3 service.

Finally, I understand that PPL's recently-approved POLR plan will set the same generation rates for GS-3 and GH-1. Therefore, once that plan goes into effect, the GH-1 rate class can be eliminated, since rates for all GH-1 customers will be lower under GS-3.

Q. Do you have any other comments regarding PPL's commercial class rate design proposal?

A. Yes. My recommendations are based on the Commission's continued acceptance of PPL's COSS methodology, which classifies distribution costs into demand and customer components. However, I recognize that experts representing the Pennsylvania Office of Consumer Advocate have, in the past, advanced an alternative theory of distribution cost causation, in which costs are classified into demand and energy components (the "peak-and-average" approach). If the Commission adopts the OCA methodology, or if it considers both the PPL approach and the peak-and-average approach for revenue allocation purposes, PPL's demand-based rate design proposal for all of the commercial classes would be hopelessly inconsistent with the approved COSS and therefore would be wholly inappropriate.

In that eventuality, PPL's commercial class rate design would need to be revisited. In particular, it would likely be necessary to recover a significant portion of distribution costs from a flat per-kWh energy charge.

5. Energy Efficiency Rider

Q. Please summarize your understanding of PPL's proposed Energy Efficiency Rider ("EER").

A. PPL proposes to expand its efforts to encourage conservation and energy efficiency among its small volume customers. The proposed programs involve a variety of customer education, appliance rebates, and other demand-side management initiatives. The initial funding amount for these programs is targeted at $2.7 million. PPL proposes to recover the costs of these programs through a reconcilable rider charge, applied as a constant percentage of distribution revenues from rate classes RS, RTS, RTD, and GS-1.

Q. Do you agree with the need for PPL to provide energy efficiency programs to its customers?

A. Philosophically I do not. In the days of fully bundled electric rates, utility-funded demand-side management ("DSM") programs were economically justified because the price signals in embedded cost rates were far below the marginal cost of providing electrical service from new generating units. Thus, it would often be less expensive for a utility to subsidize conservation than it was for it to construct new generating facilities. Under those conditions, a utility could reduce its overall costs by making DSM investments. However, with the advent of market-based rates for generation, that economic justification has disappeared.

Nevertheless, I recognize that PPL has not yet moved to market-based generation rates. I also recognize that there is political support for requiring distribution utilities to retain the historical responsibility for DSM that their integrated predecessors had. While assigning utilities the responsibility for DSM may be akin to letting the fox guard the henhouse (because demand reductions reduce base rate revenues and margins), I am not objecting to PPL's claim for $2.7 million in this proceeding. However, I encourage the Commission to proceed with caution. Specifically, I recommend that the Commission limit recovery to the $2.7 million identified by PPL in this proceeding, by either including these costs in base rates on a non-reconcilable basis or by setting a cap on the reconcilable amounts.

Q. Do you have any other concerns about the proposed EER?

A. Yes I do. PPL proposes to recover the EER as a percentage of distribution revenues. That percentage will be the same for Rates RS, RTS, RTD, and GS-1. This is an inequitable allocation of cost responsibility for two reasons.

First: Judging by the programs listed by PPL in its filing, it appears that much of the effort is focused on PPL's RTS customers. By applying the same percentage charge to all customer classes, PPL's proposal will not match costs and benefits.

Second: By imposing costs as a percentage of distribution revenues, PPL's proposal will result in a disproportionately higher cost for those classes that over-recover allocated costs (i.e., GS-1) than for the classes that under-recover allocated costs. As such, it compounds the inequity long-imposed on PPL's GS-1 customers.

This inequity persists despite the fact that PPL's proposed revenue allocation in this proceeding will make substantial progress toward cost-based rates. However, as an example. RTS customers will still pay only about 1.4 cents per kWh for distribution service, while GS-1 customers will pay 3.9 cents per kWh. Thus, PPL's EER proposal will charge GS-1 customers almost three-times as much per kWh as RTS customers, despite the apparent focus of the program on RTS customers.

Therefore, to the extent that the Commission approves a separate rider for these programs, I recommend that the charge be class-specific, based on the costs of providing the benefits to each rate class.

Q. Does this conclude your direct testimony?

A. Yes it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than twenty years of consulting experience, focusing primarily on the energy, metals, and mining industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. His practice currently focuses primarily on utility regulation, and he has provided analysis and expert testimony in numerous U.S. and Canadian jurisdictions. In addition, as Treasurer of IEc since 1995, Mr. Knecht is responsible for the firm's accounting, finance and tax planning, as well as administration of the firm's retirement plans. Mr. Knecht's consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht provides analysis and expert testimony in industry restructuring, base rates and purchased energy cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht has analyzed the economics and financial issues of electric industry restructuring, stranded cost determination, fair rate of return, claimed utility expenses, cost allocation methods and rate design issues.
- For independent power producers and industrial customers in Alberta, Mr. Knecht has provided analysis and expert testimony in a variety of electric industry proceedings, including industry restructuring, cost unbundling, stranded cost recovery, transmission rate design, cost allocation and rate design.
- For industrial customers in Québec, Mr. Knecht has prepared economic analysis and expert testimony in regulatory proceedings regarding cost allocation, compliance with legislative requirements for cross-subsidization, and rate design.
- As part of international teams of experts, Mr. Knecht has prepared the economic and financial analysis for industry restructuring studies involving the steel and iron ore industries in Venezuela, Poland, and Nigeria.
- For the U.S. Department of Justice and for several private sector clients, Mr. Knecht has prepared analyses of economic damages in a variety of litigation matters, including ERISA discrimination, breach of contract, fraudulent conveyance, natural resource damages and anti-trust cases.
- Mr. Knecht participates in numerous projects with colleagues at IEc preparing economic and environmental analyses associated with energy and utility industries for the U.S. Environmental Protection Agency.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining Industrial Economics as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

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IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-00072245	Pennsylvania Public Utility Commission	Pike County Light & Power Company	March 2007	Pennsylvania Office of Small Business Advocate	Default service procurement, rate design
R-00072043	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Company	March 2007	Pennsylvania Office of Small Business Advocate	Design day requirements
C-20065942	Pennsylvania Public Utility Commission	Pike County Light & Power Company	November 2006	Pennsylvania Office of Small Business Advocate	Wholesale power procurement by provider of last resort
R-3610-2006	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2006	AQCIE/CIFQ	Post-patrimonial generation cost allocation; cross-subsidization; rate design
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	September 2006	Pennsylvania Office of Small Business Advocate	Affidavit: POLR rates, wholesale to retail.
R-00061493	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corporation	September 2006	Pennsylvania Office of Small Business Advocate	Rate of return, load forecasting, cost allocation, revenue allocation, rate design, revenue decoupling.
R-00061398	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	August 2006	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-00061365	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Merger savings, cost allocation, revenue allocation, rate design.
R-00061519	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
R-00061518	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
A-125146	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Southern Union Company	June 2006	Pennsylvania Office of Small Business Advocate	Public benefits of proposed sale of PG Energy to UGI; asset management agreement.
R-00061355	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2006	Pennsylvania Office of Small Business Advocate	Gas supply and hedging plan; procedural issues
R-00061296	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2006	Pennsylvania Office of Small Business Advocate	Gas procurement and procedural issues.
R-00061246	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2006	Pennsylvania Office of Small Business Advocate	Gas procurement; unaccounted for gas retention rates

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
2005-002 Refiling	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	February 2006	New Brunswick Public Intervenor	Cost allocation, rate design
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	December 2005	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design for POLR supplies.
R-3579-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2005	AQCIE/CIFQ	Generation cost allocation; cross-subsidization; revenue allocation
2005-002	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	August 2005	New Brunswick Public Intervenor	Cost allocation, rate design
R-00050538	Pennsylvania Public Utility Commission	PG Energy	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement diversification
R-00050540	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging, retention rates, sharing mechanism
R-00050340	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging and diversification.
R-3563-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	April 2005	AQCIE/CIFQ	Generation cost allocation; industrial demand response
R-00050264	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, risk hedging, financing costs in the gas cost rate.
R-00050216	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2005	Pennsylvania Office of Small Business Advocate	Gas supply procurement and forward pricing policies.
EB-2004-0542	Ontario Energy Board	Union Gas Limited	March 2005	Tribute Resources Inc.	Cost allocation and rate design for service to embedded storage pools.
R-00049884	Pennsylvania Public Utility Commission	Pike County Light and Power (Gas Service)	January 2005	Pennsylvania Office of Small Business Advocate	Fair rate of return, cost allocation, class revenue assignment.
R-00049656	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	December 2004	Pennsylvania Office of Small Business Advocate	Fair rate of return, uncollectibles costs, automatic rate adjustments, cost allocation, rate design.
R-3541-2004	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2004	AQCIE, CIFQ	Allocation of post-patrimonial generation costs.

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
C-20031302	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	July 2004	Pennsylvania Office of Small Business Advocate	Customer assistance program funding and cost allocation.
R-049255	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	June 2004	Pennsylvania Office of Small Business Advocate	Transmission and distribution cost allocation, rate design, automatic distribution increases.
P-042090 et al.	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2004	Pennsylvania Office of Small Business Advocate	Collections and universal service cost issues.
RP-2003-0203	Ontario Energy Board	Enbridge Gas Distribution	May 2004	Vulnerable Energy Consumers Coalition et al.	Cost allocation, rate design for pipeline and storage costs
R-049157 P-042090	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2004	Pennsylvania Office of Small Business Advocate	Cash receipts reconciliation clause
R-049108	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2004	Pennsylvania Office of Small Business Advocate	Uncollectible cost responsibility for standby charges
Application 1306819	Alberta Energy and Utilities Board	ENMAX Power Corporation	January 2004	Calgary Industrial Group Calgary Building Owners	T&D cost allocation, rate design, ratepayer equity funding
R-3492-2002 Phase 2	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2003	AQCIE, CIFQ	Rate policy, cross-subsidization
R-038168	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	July 2003	Pennsylvania Office of Small Business Advocate	Cost allocation, deficiency assignment, rate design, pension cost reconciliation, rate of return
R-3492-2002 Phase 1	Régie de l'Énergie, Québec	Hydro Québec Distribution	January 2003	AQCIE, AIFQ	Cost allocation; maintenance of historical cross-subsidization
M-021612	Pennsylvania Public Utility Commission	Philadelphia Gas Works	September 2002	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, cost allocation, rate unbundling
R-027385	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms.
1250932	Alberta Energy and Utilities Board	Aquila Networks Canada (Alberta) Ltd.	July 2002	Senior Petroleum Producers Association	Distribution plant and cost allocation, rate design.
R-027204	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2002	Pennsylvania Office of Small Business Advocate	Purchased gas cost incentive mechanisms, rate design

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DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-3477-2001	Régie de l'Énergie, Québec	Hydro Québec Distribution	May 2002	AQCIE, AIFQ	Classification/allocation of generation costs, subject to constant unit cost constraint.
1248859	Alberta Energy and Utilities Board	ESBI Alberta Limited	March 2002	IPPSA	Transmission congestion management principles
R-016378	Pennsylvania Public Utility Commission	Philadelphia Gas Works	August 2001	Pennsylvania Office of Small Business Advocate	Cost of gas; commodity price forecasting
R-016179	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2001	Pennsylvania Office of Small Business Advocate	Recovery of CAP costs; PGC treatment of pipeline credits
R-005277	Pennsylvania Public Utility Commission	PFG Gas Inc. and North Penn Gas Company	November 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design.
R-3443-2000	Régie de l'Énergie, Québec	Société en commandite Gaz Métropolitain	November 2000	Industrial Gas Users Association (ACIG)	Tariff unbundling
990005	Alberta Energy and Utilities Board	ESBI Alberta Limited	November 2000	IPPSA	Location-based credits for transmission rates
R-005119	Pennsylvania Public Utility Commission	PG Energy (Southern Union)	July 2000	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, weather normalization
R-994788	Pennsylvania Public Utility Commission	PFG Gas, Inc. and North Penn Gas Company	February 2000	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
R-994785	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corp.	December 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
R-994783	Pennsylvania Public Utility Commission	PG Energy, Inc.	November 1999	Pennsylvania Office of Small Business Advocate	Natural gas restructuring, retail access, tariff design
99005	Alberta Energy and Utilities Board	ESBI Alberta Limited (Transmission Administrator)	September 1999	IPPSA	Transmission tariff cost allocation, rate design, industry restructuring
RE95080	Alberta Energy and Utilities Board	Alberta Power Limited	December 1998	Independent Power Producers Society of Alberta and SPPA	Electric industry restructuring, rate unbundling, cost allocation and rate design.
RE95081	Alberta Energy and Utilities Board	TransAlta Utilities Corporation	November 1998	IPPSA and Senior Petroleum Producers Assn.	Industry restructuring, cost allocation, rate design.

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DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Expansion Feasibility Test	Public Utilities Board of Manitoba	Centra Gas Manitoba	August 1998	Simplot Canada Limited	Expansion feasibility and customer contribution methodology
R-984280	Pennsylvania Public Utility Commission	PG Energy, Inc.	August 1998	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue deficiency assignment, rate design
EO97070455	New Jersey Board of Public Utilities	Atlantic City Electric Company	February 1998	New Jersey Board of Public Utilities	Industry restructuring, audit of unbundled rates
R-973981	Pennsylvania Public Utility Commission	Allegheny Power (West Penn Power)	January 1998	Pennsylvania Office of Small Business Advocate	Industry restructuring, cost unbunding, cost allocation, and rate design.
R-973954	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	August 1997	Pennsylvania Office of Small Business Advocate	Restructuring, stranded costs, market price forecasting, cost allocation, and rate design.
1996 Electric Utility Tariff Applications	Alberta Energy & Utilities Board	TransAlta Utilities, Alberta Power Edmonton Power, Grid Company of Alberta	October 1996	Independent Power Producers Society of Alberta (IPPSA)	Industry restructuring; transmission cost allocation and rate design.
R-963612	Pennsylvania Public Utility Commission	PG Energy, Inc.	October 1996	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal.
R-953444	Pennsylvania Public Utility Commission	Trigen-Philadelphia Energy Corp.	November 1995	Pennsylvania Office of Small Business Advocate	Steam energy cost rate -- direct and rebuttal.
R-953406	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	October 1995	Pennsylvania Office of Small Business Advocate	Weather normalization, cost allocation and rate design.
R-953297	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Gas Division)	May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and surrebuttal.
R-943271	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	April/May 1995	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct and rebuttal
EBRO 488	Ontario Energy Board	Natural Resource Gas Limited	November 1994	Natural Resource Gas Limited	Customer classification, cost allocation and rate design.
RE92071	Alberta Public Utilities Board	Alberta Power Limited	November 1994	Independent Power Producers Society of Alberta	Cost allocation and rate design for export transmission service.
R-942986	Pennsylvania Public Utility Commission	West Penn Power Company	August 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design.

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-932862	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Electric Division)	March 1994	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design -- direct, rebuttal and surrebuttal.
EBRO 485, and Generic Direct Purchase Hearings	Ontario Energy Board	Consumers' Gas Company, Ltd.	August 1993,September 1993.	Canadian Independent Gas Marketing Association	Classification and allocation of marketing and administrative costs.
Hearings for Cost of Service and Rate Design	Nova Scotia Utility and Review Board	Nova Scotia Power, Inc.	May 1993	Bowater Mersey Paper Company, Ltd.	Classification of bulk power costs, rate design for interruptible service and other rate design issues.
Generic Hearing #4	Board of Commissioners of Public Utilities, New Brunswick	New Brunswick Power Corporation	November 1991	Large Power Users Group	Review of cost allocation and rate design.
EBRO-473	Ontario Energy Board	Consumers' Gas Company, Ltd.	October 1991	Ontario Energy Board Staff	Cost allocation and rate design
EBRO-470	Ontario Energy Board	Union Gas, Ltd.	February 1991	Ontario Energy Board Staff	Cost allocation and rate design; evaluation of load shifting study.
Rate Area Boundaries Hearings	Prince Edward Island Public Utilities Commission	Maritime Electric Co., Ltd.	February 1991	PEI Island Department of Energy and Forestry	Customer classification by geographical area.
EBRO-467	Ontario Energy Board	Centra Gas, Ltd.	January 1991	Ontario Energy Board Staff	Cost allocation and rate design for technology, cogen and bypass.
Arbitration Hearings	Arbitrator	ARINC, Inc.	July 1990	ARINC Inc.	Cost allocation and rate design for aircraft to ground data communications service.
EBRO-462	Ontario Energy Board	Union Gas, Ltd.	January 1990	Ontario Energy Board Staff	Seasonal cost allocation study, and allocation of costs to export markets.
NSPC-857	Nova Scotia Board of Commissioners of Public Utilities	Nova Scotia Power Corp.	February 1989	Interruptible industrial customers	Cost allocation and rate design of interruptible electric service.

EXHIBIT IEc-2

REVENUE ALLOCATION ANALYSES

Exhibit IEc-2, Schedule A															
PPL Distribution Revenue Allocation Proposal: Adjusted For Remand Settlement from Exhibit JMK-2A															
	Total	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
Adjusted "Present" Rates															
Net Rate Revenues	631,657	386,480	3,991	73,866	109,784	29,104	1,781	1,168	564	36	333	538	6,459	17,518	35
Other Revenues	43,026	29,029	642	3,987	6,364	1,306	155	160	50	20	27	39	340	918	(11)
Total Revenues	674,683	415,509	4,633	77,853	116,148	30,410	1,936	1,328	614	56	360	577	6,799	18,436	24
O&M Expenses	339,552	243,401	5,345	27,195	37,341	9,622	484	436	98	36	88	22	2,731	12,741	12
Dep'n/Amortization	111,824	73,527	2,102	10,144	15,524	3,651	182	329	87	32	58	20	1,217	4,941	10
Total Taxes	99,062	44,714	(1,306)	17,908	27,462	7,459	557	229	185	(7)	99	235	1,212	314	1
Return	124,245	53,867	(1,508)	22,606	35,821	9,678	713	334	244	(5)	115	300	1,639	440	1
Total Cost	674,683	465,671	11,773	56,573	84,022	21,167	1,059	1,061	258	98	241	47	6,231	26,447	33
Rate Base	2,022,966	1,321,699	38,737	179,448	298,479	75,648	3,836	3,072	820	294	821	190	21,654	78,174	94
Rate of Return	6.14%	4.08%	-3.89%	12.60%	12.00%	12.79%	18.59%	10.87%	29.76%	-1.70%	14.01%	157.89%	7.57%	0.56%	1.06%
Indexed RoR	100.0%	66.4%	-63.4%	205.1%	195.4%	208.3%	302.6%	177.0%	484.5%	-27.7%	228.1%	2570.9%	123.2%	9.2%	17.3%
Normalized R/C Ratio	100.0%	89.8%	39.0%	136.6%	135.4%	140.6%	178.5%	125.3%	236.4%	57.6%	146.5%	1164.1%	107.3%	69.9%	73.3%
Differential RoR	0.00%	-2.07%	-10.03%	6.46%	5.86%	6.65%	12.45%	4.73%	23.61%	-7.84%	7.87%	151.75%	1.43%	-5.58%	-5.08%
Subsidy	-	(50,162)	(7,140)	21,280	32,126	9,243	877	267	356	(42)	119	530	568	(8,011)	(9)
Tentative PPL Proposed Rates															
Percent Rate Increase	13.1%	19.9%	23.7%	1.1%	0.5%	-1.2%	-6.7%	-11.3%	-23.1%	-21.0%	-0.2%	0.0%	8.5%	23.5%	10.7%
Rate Increase	83,036	76,818	946	828	521	(353)	(120)	(131)	(130)	(8)	(1)	-	551	4,110	4
Rate Revenues	714,693	463,298	4,937	74,694	110,305	28,751	1,661	1,037	434	28	332	538	7,010	21,628	39
Other Revenues	43,513	29,542	640	4,004	6,455	1,268	168	156	53	23	27	45	331	815	(13)
Total Revenues	758,206	492,840	5,577	78,698	116,760	30,019	1,829	1,193	487	51	359	583	7,341	22,443	26
O&M Expenses	340,221	244,018	5,336	27,237	37,357	9,623	484	437	98	36	88	22	2,732	12,741	12
Dep'n/Amortization	111,824	73,527	2,102	10,144	15,524	3,651	182	329	87	32	58	20	1,217	4,941	10
Total Taxes	136,446	79,292	(880)	18,288	27,749	7,288	509	168	127	(10)	99	238	1,457	2,119	2
Return	169,715	96,003	(981)	23,029	36,130	9,457	654	259	175	(7)	114	303	1,935	2,642	2
Total Cost	758,206	520,172	13,348	64,050	96,390	24,305	1,219	1,191	292	109	276	56	7,124	29,637	37
Rate Base	2,022,966	1,321,699	38,737	179,448	298,479	75,648	3,836	3,072	820	294	821	190	21,654	78,174	94
Rate of Return	8.39%	7.26%	-2.53%	12.83%	12.10%	12.50%	17.05%	8.43%	21.34%	-2.38%	13.89%	159.47%	8.94%	3.38%	2.13%
Indexed RoR	100.0%	86.6%	-30.2%	153.0%	144.3%	149.0%	203.2%	100.5%	254.4%	-28.4%	165.5%	1900.9%	106.5%	40.3%	25.4%
Revenue/Cost Ratio	100.0%	94.7%	41.8%	122.9%	121.1%	123.5%	150.1%	100.2%	166.8%	46.7%	130.0%	1046.6%	103.1%	75.7%	70.6%
Differential RoR	0.00%	-1.13%	-10.92%	4.44%	3.72%	4.11%	8.66%	0.04%	12.95%	-10.77%	5.50%	151.08%	0.55%	-5.01%	-6.26%
Subsidy	-	(27,332)	(7,771)	14,648	20,370	5,714	610	2	195	(58)	83	527	217	(7,194)	(11)
Progress Toward Cost-Based Rates															
Indexed RoR		60%	20%	50%	54%	55%	49%	99%	60%	-1%	49%	27%	72%	34%	10%
Normalized R/C Ratio		49%	5%	38%	40%	42%	36%	99%	51%	-26%	35%	11%	58%	19%	-10%
Differential RoR		46%	-9%	31%	37%	38%	30%	99%	45%	-37%	30%	0%	62%	10%	-23%
Subsidy		46%	-9%	31%	37%	38%	30%	99%	45%	-37%	30%	0%	62%	10%	-23%

Exhibit IEc-2, Schedule B

PPL Distribution Revenue Allocation Proposal: Adjusted For Remand Settlement, IEc Scaleback Proposal

	Total	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
Adjusted "Present" Rates															
Net Rate Revenues	631,657	386,480	3,991	73,866	109,784	29,104	1,781	1,168	564	36	333	538	6,459	17,518	35
Other Revenues	43,026	29,029	642	3,987	6,364	1,306	155	160	50	20	27	39	340	918	(11)
Total Revenues	674,683	415,509	4,633	77,853	116,148	30,410	1,936	1,328	614	56	360	577	6,799	18,436	24
O&M Expenses	339,552	243,401	5,345	27,195	37,341	9,622	484	436	98	36	88	22	2,731	12,741	12
Dep'n/Amortization	111,824	73,527	2,102	10,144	15,524	3,651	182	329	87	32	58	20	1,217	4,941	10
Total Taxes	99,062	44,714	(1,306)	17,908	27,462	7,459	557	229	185	(7)	99	235	1,212	314	1
Return	124,245	53,867	(1,508)	22,606	35,821	9,678	713	334	244	(5)	115	300	1,639	440	1
Total Cost	674,683	465,781	11,789	56,526	83,952	21,147	1,057	1,060	258	98	241	46	6,230	26,465	33
Rate Base	2,022,966	1,321,699	38,737	179,448	298,479	75,648	3,836	3,072	820	294	821	190	21,654	78,174	94
Rate of Return	6.14%	4.08%	-3.89%	12.60%	12.00%	12.79%	18.59%	10.87%	29.76%	-1.70%	14.01%	157.89%	7.57%	0.56%	1.06%
Indexed RoR	100.0%	66.4%	-63.4%	205.1%	195.4%	208.3%	302.6%	177.0%	484.5%	-27.7%	228.1%	2570.9%	123.2%	9.2%	17.3%
Normalized R/C Ratio	100.0%	89.7%	39.0%	136.8%	135.9%	141.1%	179.3%	125.5%	236.9%	57.7%	146.9%	1192.5%	107.5%	69.9%	73.4%
Differential RoR	0.00%	-2.07%	-10.03%	6.46%	5.86%	6.65%	12.45%	4.73%	23.61%	-7.84%	7.87%	151.75%	1.43%	-5.58%	-5.08%
Subsidy	-	(50,272)	(7,156)	21,327	32,196	9,263	879	268	356	(42)	119	531	569	(8,029)	(9)
IEc Scaleback Rates	2.05%														
Adj. Full Increase %	13.15%	19.88%	23.71%	1.12%	0.47%	-1.21%	-6.73%	-11.26%	-23.05%	-20.98%	-0.16%	0.00%	8.53%	23.46%	10.66%
Net Increase %	11.0%	17.8%	21.7%	-2.0%	-1.6%	-3.3%	-8.8%	-2.1%	-25.1%	32.5%	-2.2%	-2.0%	6.5%	21.4%	31.5%
PPL Rate Increase	83,036	76,818	946	828	521	(353)	(120)	(131)	(130)	(8)	(1)	-	551	4,110	4
IEc Adj. Full Increase	-			(159)				131		20					8
IEc GS-1 FDR	(669)			(669)											
Differential Scaleback	(12,917)	(7,904)	(82)	(1,511)	(2,245)	(595)	(36)	(24)	(12)	(1)	(7)	(11)	(132)	(358)	(1)
Rate Revenues	701,107	455,395	4,856	72,356	108,060	28,156	1,625	1,144	422	48	326	527	6,878	21,270	46
Other Revenues	43,513	29,542	640	4,004	6,455	1,268	168	156	53	23	27	45	331	815	(13)
Total Revenues	744,620	484,936	5,495	76,359	114,515	29,424	1,793	1,300	475	70	352	572	7,209	22,085	33
O&M Expenses	340,221	244,018	5,336	27,237	37,357	9,623	484	437	98	36	88	22	2,732	12,741	12
Dep'n/Amortization	111,824	73,527	2,102	10,144	15,524	3,651	182	329	87	32	58	20	1,217	4,941	10
Total Taxes	130,340	75,740	(917)	17,237	26,740	7,020	493	216	122	(1)	96	233	1,398	1,958	5
Return	162,235	91,652	(1,026)	21,742	34,894	9,129	634	318	169	4	110	297	1,862	2,445	6
Total Cost	744,620	511,343	13,103	62,828	94,344	23,786	1,192	1,168	286	107	270	53	6,978	29,125	36
Rate Base	2,022,966	1,321,699	38,737	179,448	298,479	75,648	3,836	3,072	820	294	821	190	21,654	78,174	94
Rate of Return	8.020%	6.93%	-2.65%	12.12%	11.69%	12.07%	16.53%	10.35%	20.57%	1.23%	13.43%	156.29%	8.60%	3.13%	6.39%
Indexed RoR	100.0%	86.5%	-33.0%	151.1%	145.8%	150.5%	206.1%	129.1%	256.5%	15.3%	167.4%	1948.8%	107.2%	39.0%	79.7%
Revenue/Cost Ratio	100.0%	94.8%	41.9%	121.5%	121.4%	123.7%	150.4%	111.3%	166.2%	65.6%	130.2%	1071.1%	103.3%	75.8%	92.2%
Differential RoR	0.00%	-1.09%	-10.67%	4.10%	3.67%	4.05%	8.51%	2.33%	12.55%	-6.79%	5.41%	148.27%	0.58%	-4.89%	-1.63%
Subsidy	-	(26,406)	(7,608)	13,531	20,171	5,638	601	132	189	(37)	82	519	231	(7,041)	(3)
Progress															
Indexed RoR		60%	19%	51%	52%	53%	48%	62%	59%	34%	47%	25%	69%	33%	75%
Normalized R/C Ratio		50%	5%	41%	40%	42%	36%	56%	52%	19%	36%	11%	56%	20%	71%
Differential RoR		47%	-6%	37%	37%	39%	32%	51%	47%	13%	31%	2%	59%	12%	68%
Subsidy		47%	-6%	37%	37%	39%	32%	51%	47%	13%	31%	2%	59%	12%	68%

OSBA STATEMENT NO. 2

BEFORE THE

Hly Jc AUG 16 2007

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-00072155
	:	
PPL ELECTRIC UTILITIES CORPORATION	:	

DOCUMENT FOLDER

Rebuttal Testimony and Exhibits of

ROBERT D. KNECHT

DOCKETED SEP 7 - 2007

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Distribution Cost Allocation Methodology
Revenue Allocation
Commercial Class Rate Design
Universal Service Cost Recovery

Date Served: July 27, 2007
Date Submitted for the Record: ______________________________

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1 Introduction and Overview

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony earlier in this proceeding and my qualifications were presented therein.

Q. What is the purpose of this testimony?

A. OSBA requested that I evaluate the cost allocation methodology offered by Pennsylvania Office of Consumer Advocate ("OCA") witness Mr. Richard Galligan, as well as the implications of that methodology for commercial class rate design were the Commission to approve it. Second, OSBA requested that I evaluate the universal service cost recovery proposal of OCA witness Mr. Roger Colton.

Q. Please summarize the conclusions from your analysis.

A. In summary, my conclusions are as follows:

- Mr. Galligan's proposed cost allocation methodology does not provide a reasonable cost basis for revenue allocation in this proceeding, for the following reasons:
  - It allocates a significant share of distribution costs on the basis of customer class annual energy use, even though there is no causal relationship between energy use and the incurrence of distribution costs;
  - It fails to recognize that secondary distribution system costs are causally related to both peak customer demands and the number of customers on the system;
  - It fails to adequately recognize that services costs are related both to the number of customers in a rate class and to the size of the customer;
  - It represents a radical departure from long-established Commission precedent for PPL Electric Utilities ("PPL"); and
  - It fails to present the information regarding the classification of costs that is necessary for class rate design.

- If Mr. Galligan's cost allocation methodology is adopted by the Commission, in whole or in part, PPL's proposed changes for rate design for the commercial classes (Rates GS-1, GS-3, and GH) would need to be *radically* revised. At a minimum, PPL's proposed demand charges for commercial customers would need to be reduced and PPL's proposed energy charges increased.
- Mr. Colton's proposal that universal service costs be broadly allocated among all customer classes is not consistent with cost causation principles or with Commission precedent. The Company's proposal regarding the allocation of universal service costs should be adopted for this proceeding.

Q. How is your rebuttal testimony organized?

A. Section 2 responds to Mr. Galligan's testimony. Section 3 responds to Mr. Colton's testimony.

2 OCA Cost of Service Study

2.1 Summary of Cost Allocation Methodology Differences

Q. Mr. Galligan bases his revenue allocation recommendations on an alternative cost allocation study, also known as a cost of service study ("COSS"). Please explain the basic differences between the methodology used in Mr. Galligan's COSS and the methodology used by PPL in its COSS.

A. Mr. Galligan contests three major aspects of PPL's cost allocation methodology.

First, the Company believes that the costs for its secondary distribution equipment are caused both by the electricity demands on the secondary system, and by the number of customers attached to the secondary system. Mr. Galligan believes that the costs for this equipment are caused only by customer demands.

Second, the Company believes that the demand-related costs for all of its distribution equipment are caused by customer *peak* demands. Mr. Galligan believes that these demand-related costs are related to both peak demand and average annual demand. He identifies his approach as a peak-and-average ("P&A") allocation method.

Third, like PPL, Mr. Galligan believes that services costs are related partly to the number of customers and partly to the size of the customer. However, PPL believes that larger customers impose somewhat more services costs than does Mr. Galligan.

Q. What are the general implications of Mr. Galligan's proposed changes to PPL's cost allocation results?

A. First, because Mr. Galligan believes that secondary distribution system costs are unrelated to the number of customers, he would assign all costs based on usage. This change would affect only those customers who are attached to PPL's distribution system at secondary distribution voltage. Therefore, this change would reduce the costs assigned to the secondary distribution classes with many smaller customers (RS and GS-1) and increase the costs assigned to the classes with fewer customers but higher electricity usage per customer (GS-3 and GH).[1]

Second, Mr. Galligan believes that distribution costs are caused both by peak demand and by average annual energy use. Because Mr. Galligan includes average energy consumption in his allocation method, his method would assign more costs to those rate classes which use more energy relative to each unit of peak demand. That is, his method would assign more costs to classes with flatter loads, i.e., classes with loads that do not fluctuate significantly. Similarly, this method would assign less costs to classes which need more power during peak periods, i.e., classes with loads that do fluctuate significantly. In effect, his method would shift costs from the "peaky" residential and GS-1 rate classes to the "less peaky" GS-3, GH, and LP-4 classes.

Third, because Mr. Galligan believes that services costs are less related to the size of the customer than does PPL, his method would assign *more* services costs to smaller customers in the RS and GS-1 rate classes, and less costs to larger customers in the RTS, GS-3 and GH classes. This change would have the effect of partially offsetting the impact of Mr. Galligan's first proposed change.

[1] Mr. Galligan's proposal has only a small impact on lighting customer classes, because most of the distribution plant costs for those classes is not allocated but is directly assigned. In addition, Mr. Galligan's method would assign more costs to residential RTS customers than PPL's method.

Q. How much of PPL's COSS would be affected by Mr. Galligan's proposed changes?

A. Virtually all of it. Mr. Galligan proposes to change the classification and allocation of virtually all major plant accounts, including substations, primary system poles and conductors, secondary system poles and conductors, line transformers, and services. The only major plant account that is unaffected by Mr. Galligan's proposed changes is meters plant. Moreover, due to the nature of PPL's COSS, the classification and allocation of general and intangible plant costs, capital-related costs (rate of return, income taxes, and depreciation), most distribution operating and maintenance ("O&M") costs, and the administrative and general ("A&G") costs would also be changed.

Therefore, Mr. Galligan's proposed COSS methodology would affect the allocation of virtually ***all costs*** related to PPL's distribution system, as compared to the way PPL has proposed to allocate them.

Q. Can you explain a little more about what cost allocation analysts mean when they talk about cost "classification" and "allocation?"

A. Yes. Simply put, when performing a COSS, the objective of cost *classification* is to determine the factor (or factors) that most directly cause the utility to incur each of the various costs. There are three major categories into which costs are classified: energy-related, peak-demand-related, and customer-related.[2]

It is not unusual for particular cost items to be caused by more than one factor, and therefore be classified into more than one category. For example, many utilities classify their secondary distribution costs as both peak demand-related and customer-related, on the theory that the utilities incur these costs because of both of those factors. In the parlance of cost allocation analysts, these costs are said to have a *customer component* and a *demand component*.

[2] One issue to recognize is that, for cost allocation purposes, annual energy is exactly the same as annual average demand. Average demand is simply annual energy divided by the number of hours in the year. For example, a 20,000 kWh per year customer has an average demand of 2.283 kW (20,000 kWh per year divided by 8,760 hours per year). Therefore, a rate class's share of annual energy is exactly the same as its share of average demand. Allocating costs on the basis of annual energy, or allocating them on the basis of average demand, produces the same arithmetic result.

The next step of a COSS is the *allocation* stage. In the allocation stage, the classified costs are assigned to each customer class in proportion to that customer class's contribution to the various classified costs. For example, if a particular cost item is classified as *energy-related*, a customer class that incurs 20 percent of the system annual energy use will be assigned 20 percent of the system's annual energy costs.

Mr. Galligan's P&A proposal can be viewed as either a change to PPL's cost classification method or to its allocation method. From a classification perspective, Mr. Galligan's proposal represents classifying costs into peak demand and average demand components, and allocating them separately. From an allocation perspective, Mr. Galligan's approach can be seen as allocating these costs using a hybrid allocation factor that reflects both peak and average demands. In this testimony, I will refer to Mr. Galligan's proposal as a cost classification methodological change.

Q. With that background, can you provide a summary of the cost classification differences between Mr. Galligan's proposal and PPL's methodology?

The differences in the cost classification approaches used in Mr. Galligan's COSS and PPL's COSS are summarized in Table IEc-R1 below:

Table IEc-R1
Comparison of Cost Classification Methods
PPL versus OCA

	PPL	*OCA*
Substations	NCP Demand	50% NCP Demand 50% Annual Energy
Primary System	NCP Demand	50% NCP Demand 50% Annual Energy
Secondary OH Lines	43% NCP Demand 57% Customer	50% NCP Demand 50% Annual Energy
Secondary UG Line	32% NCP Demand 68% Customer	50% NCP Demand 50% Annual Energy
Line Transformers	47% NCP Demand 53% Wtd. Customer*	50% NCP Demand 50% Annual Energy
Services	23% NCP Demand 77% Wtd. Customers*	Weighted Customers*
Meters	Weighted Customers*	Weighted Customers*

* *For the reasons explained below, a weighed customer classification approach implicitly recognizes both the number of customers and the peak demand of the customers.*

OH refers to overhead lines. UG refers to underground lines.

NCP refers to class non-coincident peak demand. NCP is a demand classification that reflects demand diversity ***within*** *each rate class but not* ***between*** *rate classes.*

In short, Mr. Galligan believes that all system plant, excluding meters and services, is caused by both peak demands and average annual energy use. ***In Mr. Galligan's view, the number of customers has no impact on cost causation at all.***

In contrast, PPL believes that its primary system plant is built to meet the peak demands put upon it, regardless of the annual average energy that flows through it. For the secondary system, PPL believes that its costs are caused both by the peak demands on the system as well as the number of customers that the system must interconnect. Regarding meters and services, the PPL and OCA approaches are similar, although PPL believes that service costs increase somewhat more for larger customers than does Mr. Galligan.

Q. Before he gets into the specifics of his proposals, Mr. Galligan begins his testimony with the assertion that "[t]he fundamental service that PPL provides is the delivery of its customers' annual energy requirements at all times during the year, and at varying rates of delivery." Do you agree with Mr. Galligan's summary of the product that PPL provides?

A. No I do not. ***The product that PPL provides is the delivery of electrical power to each customer's premises exactly when it is demanded.*** This product has two important attributes that contribute to cost causation. Both are either overlooked or given short shrift in Mr. Galligan's definition.

First, the power demanded by most customers fluctuates continuously. In other words, it fluctuates from instant to instant -- not just annually, monthly, or even hourly. Because customers have no way to store electricity on their shelves or in their closets, PPL must be able to deliver the product exactly when it is demanded. Moreover, the inability of the customer to store electric energy makes the averaging of demand irrelevant for most costs. If the customer could store energy, he could have PPL deliver it on a constant basis. The customer could put it in his closet when he doesn't need it, and take it out when he does. Under those conditions, the annual average energy demand would be a cost determinant. However, in the real world, averaging demands that fluctuate from instant to instant has no relevance to causation. Even for electricity supply, energy costs vary from minute to minute in modern spot markets. A kWh of energy consumption at 5 p.m. on the hottest day of the summer cannot be considered identical for cost causation purposes to a kWh of energy consumed at 3 a.m. on a day in April.

Second, PPL does not have the luxury of delivering electricity to the local supermarket or to a warehouse, where it can be picked up by the customer at his convenience. PPL must construct facilities to fully deliver the product directly to the customer's residence or place of business. This means that PPL must interconnect that customer to the grid.

Thus, Mr. Galligan's description of the product provided by PPL includes an irrelevant consideration (annual average energy demand). Furthermore, his description pays little heed to the instantaneously varying characteristic of the product. Finally, his description ignores altogether the issue of the location to which the electricity is delivered.

2.2 Secondary Plant Classification

Q. Let's start with the issue of whether or not secondary distribution costs are causally related to the number of customers served. Mr. Galligan argues that there is no customer component to distribution system costs because PPL does not provide a "connection service," i.e., PPL does not provide a service that would connect a customer who is using no electricity. Is that a valid justification for not recognizing a customer component of distribution costs?

A. No it is not. First, as I explained earlier, connecting each customer is an integral part of the product that PPL provides. While it is not the only attribute, it is most certainly an important one. Therefore, the cost of connecting the customer should be a basis for cost allocation. That logic applies whether we are addressing service drops or secondary distribution poles and conductors.

Many commonplace pricing practices show the fallacy of Mr. Galligan's logic. Consider the car rental business. Most companies impose a significant share of their charges in the form of a fixed daily rate for the car, regardless of whether or not the customer actually drives the car. Under Mr. Galligan's logic, because no customer would want to rent a car and not drive it, no car rental company should price its service on any basis other than the number of miles that the car is driven. However, even though the car rental company does not provide a "connection" service in the form of leasing cars that will not be driven, it prices its service on the number of days the car is leased, because that is how the rental car company incurs its own costs. It does not price its product solely based on miles driven, even though that is the primary reason for renting a car.

Q. Is there any basis for concluding that distribution costs are causally related to both customer demands and to the number of customers?

A. Yes. As I explained in my direct testimony, distribution plant must be built to satisfy two needs. First, the distribution plant must be large enough to meet the peak demands of the customers served by the distribution equipment. Second, the distribution system must be built to interconnect all of the customers on the system.

The first aspect of system design recognizes that costs are, in part, caused by peak demands, i.e., the maximum amount of electricity each customer uses at any one time. The second aspect of system design recognizes that costs are related to the geographic distribution of the customer base, i.e., where each customer is located relative to the other customers. In general, the more customers on the system, the more spread out the distribution system must become, and the more poles, transformers and conductor feet that must be installed. It simply costs more to provide distribution service to one hundred 5-kW customers than it does to provide service to five 100-kW customers. As I explained in response to PPL-OSBA-1:

> *The number of poles and transformers, as well as conductor footage, are related to load density. It is unarguable that it requires more distribution equipment to serve 500 kW of load in a tight geographic location than to serve 500 kW of load spread out over a rural area.*
>
> *Thus, larger customers have proportionately less cost responsibility for distribution equipment for two reasons. First, simply by having a higher load in a single location, larger customers contribute less per kW to distribution cost causation than geographically separate smaller customers. By definition, a single load is more geographically dense than multiple loads. Second, larger business customers tend to be more concentrated than smaller residential customers, particularly in suburban and rural areas. PPL Electric confirms this statement for its service territory, in its responses to OCA-V-16 and OCA-V-17. Because the smaller residential customers tend to be more rural and therefore in lower load density areas, they contribute more per kW of demand to distribution cost causation than larger business customers.*[3]

Q. Mr. Galligan cites Professor Bonbright's famous text as a reason to reject the inclusion of a customer component in distribution costs. Do you agree?

A. Professor Bonbright's critique of the inclusion of a customer component of costs is somewhat perplexing, since theoretical economists recognize that a product's "production cost function" can have many factors that contribute to cost incurrence. For the reasons I

[3] PPL-OSBA-1. All referenced interrogatory responses are attached in Exhibit IEc-1R.

explained above, common sense suggests that the number of customers would be a logical factor to consider in measuring cost causation. Therefore, it is obvious that Professor Bonbright somehow concluded that the number of customers did not correlate well with distribution costs (despite its intuitive appeal to PPL's engineers and at least some economists).

When pursued further, it appears that Professor Bonbright's rejection of the idea of a customer component rests entirely on the following assessment:

> *What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers.*[4]

In effect, Professor Bonbright concludes that there is no relationship between number of customers and the length of the overall distribution system, based on his economist's intuition, as well as a statistical analysis by Mr. Lessels.[5]

However, as I noted above, PPL has already submitted evidence that its smaller customers are located in the less geographically dense portions of PPL's service territory. Therefore, Bonbright's claim that density does not affect costs is not consistent with the evidence, at least as far as PPL's system is concerned.

Second, Mr. Lessels' statistical analysis appears to be of no relevance to PPL's distribution system. His analysis has been criticized for including only those utilities which were borrowing from the U.S. Rural Electrification Administration. Therefore, Mr. Lessels' limited sample casts doubt on Professor Bonbright's observation that Lessels conducted a "systematic" analysis. In addition, Mr. Lessels' analysis has been criticized because it was conducted during a time (1971 through 1978) when farms were closing

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[4] Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, page 491.

[5] This analysis is referenced as "The Economics of Electric Distribution System Costs and Investments," David J. Lessels, Public Utilities Fortnightly, Dec. 4, 1980, pages 37-40.

and customers were relocating to more densely populated areas.[6] For these reasons, I deem that Mr. Lessels' analysis, and Professor Bonbright's conclusion, have very little relevance to PPL's cost causation in this proceeding.

Finally, even Professor Bonbright admits:

> *In actual practice the vast majority of utilities use some form of minimum system to classify costs, which is in line with the FERC accounts.*

Thus, by his own admission, Professor Bonbright's opinion is not consistent with the judgment of most utilities and regulators. As such, I do not believe it constitutes sufficient evidence upon which to reverse Commission precedent or to reject a commonly used methodology.

Q. In addition to the vast majority of utilities cited by Professor Bonbright, do other authorities on cost allocation support classifying distribution system costs into both customer and demand components?

A. Yes. The NARUC Electric Utility Cost Allocation Manual indicates that both primary and secondary distribution costs should be classified into demand and customer components.[7]

In addition, the NARUC Manual cites the minimum system approach as one of the standard methods for making that classification.[8] Finally, Constantine Bary advocates a similar approach in his text on electric system costing.[9]

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[6] See, for example, "Development of Demand/Customer Classification Factors for Distribution Assets," Foster Associates, Inc., prepared for ATCO Electric Ltd., May 2004. See http://www3.eub.gov.ab.ca/eub/dds/iar_query/ShowAttachment.aspx?DOCNUM=453821

[7] As I mentioned in my direct testimony, it is important to recognize that, if PPL had scrupulously followed the manual and classified both secondary and primary system costs into customer components, it would have allocated even more costs to smaller customers and less to the larger customers. Therefore, PPL has already implicitly used a compromise methodology between a minimum system approach and the zero-customer-component approach advocated by Mr. Galligan.

[8] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January 1992. For example, the manual states, "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs." (page 90)

Q. Mr. Galligan goes on to complain that the minimum system methods used by PPL for classifying costs are unstable and therefore unreliable. He cites two changes in the cost classification percentages for line transformers. Do you agree with this critique?

A. No I do not. Mr. Galligan claims that the customer component of line transformer costs varies from 23 percent in "the PPL case prior to its 2004 rate case," to 63 percent in the 2004 base rates case, and to 53 percent in the current case. While I am unsure where Mr. Galligan got his figures, my records from PPL's 1995 base rates case indicate that the line transformer customer component in that case was 56 percent, not 23 percent.[10] In the 2004 proceeding, my records indicate that PPL's proposed customer component was 70 percent, not 63 percent. In the current proceeding, I can confirm that PPL's proposed customer component for line transformers is 53 percent.[11]

In general, a cost classification range from 56 percent to 70 percent to 53 percent over a 12-year period does not indicate that the methodology is unstable. Furthermore, such a range certainly does not justify Mr. Galligan's assumption that the customer component should be zero in every period. Moreover, I note that my recommendation in the 2004 proceeding was for a customer component of 50 percent for line transformers, based on a zero-intercept analysis. In the current proceeding, PPL has made an adjustment for the load carrying capability of the minimum system, thereby bringing the customer component down into the range that I recommended. In addition, it is likely that PPL's adjustment will tend to dampen the effects of any changes on how the minimum system is defined. Thus, Mr. Galligan's concerns about the instability of the methodology are overstated.

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[9] Operational Economics of Electric Utilities, Bary, Constantine W., Columbia University Press, 1963, page 29.

[10] My records supporting the 56 percent cost classification for line transformers include Exhibit R2 of my rebuttal testimony, the direct testimony of CEPFOD witness Dr. Steven Anderson (page 56), and the workpapers of OCA Witness Dr. Charles E. Johnson (attached as Exhibit R7 to my rebuttal testimony).

[11] All of these classification percentages represent an average of the classification percentages for overhead and underground transformers. Note also that PPL allocates the customer-related transformer costs using a weighted customer allocation factor. Because this factor partially reflects the size of the customer, it implicitly includes a demand component. Thus, the *effective* customer component of costs is lower than that reported in this paragraph.

Moreover, Mr. Galligan would apparently sacrifice accuracy on the altar of cost allocation stability. Mr. Galligan proposes to reject a methodology that makes a reasonable estimate of the customer component of costs because it produces results that vary somewhat from year to year. In so doing, Mr. Galligan is essentially abandoning the effort to accurately classify costs in favor of a methodology that is known with certainty to be wrong.

Finally, it is my view that the issue of rate stability is better addressed in the revenue allocation and rate design phases of a regulatory proceeding, rather than in the cost allocation phase. The goal of cost allocation should be to provide the most accurate assessment of costs caused by each customer class, not to simply adopt an approach that provides the most stable results from proceeding to proceeding. To the extent that cost responsibility shifts from proceeding to proceeding, its effects can and should be mitigated by consideration of the principle of gradualism in both the revenue allocation and rate design phases of a base rates proceeding.

2.3 Classification of Usage-Related Distribution Costs

Q. Let's turn to the issue of the classification of those costs that are related to electricity usage, i.e., the costs that are deemed not to be related to the number of customers. What is the basic principle that underpins PPL's existing methodology?

A. As I mentioned earlier, distribution equipment must be built with sufficient capacity to meet the *peak* demands that are placed on it. Therefore, each rate class's contribution to the peak demands on the equipment contributes to the size and therefore the cost of the equipment. The usage of the equipment outside of the peak period has no effect on costs. Therefore, any customer demands that do not contribute to the peak, or that could not reasonably contribute to the peak, are not relevant for cost causation.

To reflect this fundamental cost principle, PPL classifies these costs as peak-demand-related. PPL then uses a class "non-coincident peak" ("NCP") demand allocation methodology as a reasonable estimate of the relevant peak demand measure for cost causation. PPL's approach is consistent with industry practice.

Q. In support of his P&A methodology, Mr. Galligan argues that it would not be practical to hook up a customer who wanted to be served in only one hour of the year, and that it is only the sustained demand over the course of the year that gives rise to the existence of a distribution system. Does this argument justify classifying primary distribution system costs into both demand and energy components?

A. No it does not. Mr. Galligan presents an extreme example, and then draws an unwarranted conclusion from it regarding cost causation. It is a fact of life that it costs the same amount to provide the capacity necessary to serve a customer who averages only 1 kW of demand over the course of the year but contributes 10 kW to distribution system peak demand as it does to serve a customer who exhibits a constant 10 kW of demand at all times. While the latter uses 10 times as much electrical energy as the former, the cost to provide the primary distribution system capacity that is necessary is the same for both. The system must simply be built to have 20 kW of capacity to serve both those customers, regardless of their respective annual energy use.

In addition, it is interesting to note that Mr. Galligan's example is not as extreme as it might appear. Consider the case of a fairly large industrial customer which wants to take service from PPL at primary distribution voltage. This customer plans to install a generator at its site which is capable of meeting the customer's load for 90 percent of the hours in the year. However, the customer wants PPL to provide backstop distribution service so that the customer will be able to have replacement power delivered at the customer's full maximum load at any time that the customer's generator trips off.

To meet this customer's requirements, PPL would need to construct its distribution system such that it is capable of meeting that customer's maximum demand. That is, PPL *will incur costs that are no different than if the customer had no self-generation,* since the full capacity needs to be in place as a backstop. However, under Mr. Galligan's peak-and-average costing methodology, the cost allocated to that customer's rate class would be only slightly more than half that of the cost that would be allocated for a customer with no generator.[12] And, of course, the extra costs incurred in providing that service to the backstop customer would need to be borne by the other rate classes.

Q. Is there another way of explaining the conceptual flaw in the use of Mr. Galligan's P&A approach?

A. The P&A approach is often criticized as a form of double-counting. Peak demand can be viewed as a combination of *average demand* and *excess demand.* Excess demand represents the difference between a rate class's peak demand and its average annual demand. The average demand represents the part of the demand that is unrelated to load fluctuations. The excess demand represents the maximum load fluctuation. This view of peak demand gave rise to a standard industry allocation methodology known as the *average and excess* ("A&E") demand methodology. In that approach, costs are allocated partly on the basis of average demand and partly on the basis of excess demand.

The P&A methodology proposed by Mr. Galligan should not be confused with the A&E approach. In the A&E approach, average demand is counted only once in the allocation, because excess demand does not include average demand. In the P&A approach, average demand is counted twice, because the peak component of the allocation methodology *includes* both average and excess demand. In effect, the P&A approach is an "average & average & excess" methodology, since average demand is counted twice.

Consider the case of a 100 kW customer with a perfectly flat load, at 100 kW every hour of the year, i.e., a "100 percent load factor" customer. This customer's excess demand is zero, because its peak demand is the same as its average demand. The A&E allocator would count this 100 kW of load only once, in the average component of the allocator. Mr. Galligan's P&A approach, however, would count the 100 kW twice, once as average demand and once as peak demand.

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[12] Under PPL's peak attribution approach, the customer's allocated costs are based on the customer's peak demand. Under the OCA peak and average approach, the cost would be allocated based on one-half the peak demand and one-half the average demand. Since the average demand is quite small with a 90% generator availability, the allocated costs are only roughly half the magnitude under the peak and average approach.

Q. Does Professor Bonbright support the use of an energy allocator for electric utility capacity costs, as proposed by Mr. Galligan?

A. No he does not. In fact, while theoretical economists tend to cast doubt on the relevance of any arbitrary allocation of "joint costs" such as distribution capacity, Professor Bonbright offers "qualified support" for the peak demand method of cost classification for capacity-related costs. He states (in economists' jargon):

> *The continued presence of peaks and valleys in public utility utilization gives qualified support to the system peak responsibility principle of capacity-cost allocation. Regardless of the reason for the persistence of peaks and valleys in the load curves of utility systems, as long as they persist they raise the problem of cost imputation as between on-peak and off-peak service. The problem is soluble, under familiar principles of joint-cost imputation subject to a number of simplifying assumptions. The reason why it is soluble, despite the general principle that joint costs are unallocable costs from the standpoint of cost analysis, is that we now have that limiting case of joint production in which one of two products, the off-peak service, is a byproduct in the strictest sense of that term, whereas the other product, the peak-time service, is the main product.*[13]

In short, and in contrast to Mr. Galligan's proposal, Professor Bonbright concludes that capacity-related costs can reasonably be assigned in proportion to the peak demands that cause the utility to need to incur additional capacity costs. Professor Bonbright goes on to qualify his support by limiting it to only incremental capacity costs. However, the incremental (or marginal) cost approach favored by Professor Bonbright is simply not used in Pennsylvania. Furthermore, Mr. Galligan has presented no incremental cost analysis.

Thus, given the context of Pennsylvania regulatory practice, Professor Bonbright's reasoning generally supports PPL's methodology.

Q. Does the NARUC Manual support Mr. Galligan's classification of distribution costs as partly energy-related?

[13] Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, page 504.

A. No it does not. As I noted earlier, the manual deems that distribution costs should be classified as peak demand- and customer-related. With respect to the appropriate allocator for demand-related costs, the manual indicates:

> *Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation. Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.*[14]

The manual does not cite the P&A approach as a standard approach to either classifying or allocating distribution costs.

2.4 Classification of Services and Meters

Q. Let's turn to Mr. Galligan's proposals for allocating meters and services plant. At page 10, he indicates that meters and services plant costs "do vary with the number of customers -- one customer, one Service and one Meter are required." He then indicates that, "I have classified and allocated Services and Meters on a customer basis." Are his statements accurate?

A. No they are not. First, neither meters costs nor services costs are incurred in direct proportion to the number of customers. Larger customers require larger, more complex and more costly meters, which are capable of recording peak demands and interval demands. Similarly, larger customers require service lines that are capable of carrying the larger customer load and are therefore more costly than the service lines for small customers. Furthermore, under Mr. Galligan's logic, the meter cost for a residential customer should be the same as that for a transmission voltage steel foundry taking service under Rate LP-5. Similarly, Mr. Galligan's logic would imply that the cost of a service drop for a residential customer should be the same as the service cost for a

[14] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, January 1992, pages 96-97.

Walmart store under Rate GS-3. However, contrary to Mr. Galligan's assumption, both meters and services costs reflect the overall size of the customer. That is, these costs are related both to the number of customers and to each customer's peak demand level. Both the service and the meter must be large enough to handle the customer's peak demand.

Second, Mr. Galligan does not practice what he preaches. For services plant, Mr. Galligan allocates the costs in proportion to the *weighted* number of customers. The weighting factor reflects the nature of the service provided (generally single-phase versus three-phase service). Thus, Mr. Galligan's approach assigns a somewhat higher service drop cost to each larger GS-3 customer than it does to each smaller GS-1 or RS customer. Unfortunately, the weighting factor Mr. Galligan uses for the customer count does not recognize that larger customer load will also lead to an increase in the cost of a service line, beyond that recognized in the single versus three phase adjustment. For that reason, PPL's methodology quite reasonably includes both a demand and a customer component for services costs. Mr. Galligan's approach therefore *understates* the services costs for larger customers, and *overstates* the costs for the smallest customers, namely the residential and GS-1 customers.

Similarly, Mr. Galligan uses PPL's weighted customer allocator for meters costs. That allocator is based on the average meter cost for each customer class. Customers with larger demands have larger and more costly meters. Therefore, the meters cost classification approach implicitly includes both a customer and a demand component.

Thus, when Mr. Galligan uses *weighted* customer allocators to assign meters and services costs, he implicitly includes both a customer component and a demand component in his cost allocation methodology. Therefore, Mr. Galligan is willing to accept the idea that meters and services costs, which he argues are customer-related, implicitly also have a demand component. Unfortunately, as discussed above, Mr. Galligan is unwilling to accept the idea that a similar duality in cost causation applies to other distribution plant.

2.5 Commission Precedent

Q. Has the Commission approved PPL's cost allocation methodology with respect to distribution cost classification in the past?

A. In general, yes it has. In PPL's 1995 rate case at Docket No. R-00942371, Administrative Law Judge Robert A. Christianson approved the Company's minimum system method for classifying distribution plant costs. He concluded:

> *A standard controversy arose about minimum system calculations. The Company used a straightforward approach which has been accepted previously and is a fairly standard approach. Variances were offered by OCA and CEPFOD. I accept the PP&L method. I also accept the PP&L approach relating to the CEPFOD argument concerning certain operating and maintenance costs.*[15]

In that proceeding, the Commission rejected the OCA's Exception that the minimum system method overstated the customer component of distribution plant costs. Specifically, the Commission ruled:

> *The ALJ's recommendation concerning issues relating to the Company's NUG capacity allocation and the Company's minimum system study are adopted and PP&L is so directed to implement these revisions.*[16]

In this current proceeding, PPL has proposed to continue using the minimum system method which the Commission approved in the 1995 case. However, as I discussed in my direct testimony, PPL has proposed a modest modification to its classification of some of the distribution plant costs, to reflect the load carrying capability of the minimum system. For the reasons presented in my direct testimony, I do not believe that PPL's modification is unreasonable. In addition, I note that the impact of PPL's proposed change from the approved methodology is relatively small, both conceptually and quantitatively.

I therefore conclude that PPL's proposal is consistent with Commission precedent.

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[15] Recommended Decision, Docket No. R-00943271C001-C0145, ALJ Robert A. Christiansen, page 208, emphasis in original.

[16] Opinion and Order, Docket No. R-00942371C001-C0145, Pennsylvania Public Utility Commission, page 197.

2.6 Revenue Allocation

Q. Do you have any conclusions regarding Mr. Galligan's revenue allocation proposal?

A. Mr. Galligan's revenue allocation is based on his COSS methodology. Because his COSS is not consistent with practical cost causation, theoretical economics or Commission precedent, I recommend that the Commission reject Mr. Galligan's proposed revenue allocation.

2.7 Rate Design Implications

Q. Suppose Mr. Galligan's cost allocation methodology were accepted. What implications does his cost allocation methodology have for commercial class rate design?

A. Mr. Galligan's proposal would have profound implications for commercial class rate design. It is important to recognize that cost classification in the COSS serves two purposes. First, it determines how the cost will be allocated. Second, and sometimes overlooked, the cost classification provides important information for rate design within each rate class.

Recall that the cost classification categories are energy-related, demand-related and customer-related. At each rate class level, these classified costs can be used as cost signals for the appropriate level of energy charges (based on kWh consumed), demand charges (based on peak kW demand) and customer charges (a flat monthly charge). When Mr. Galligan proposes to substantially reduce the customer component of distribution costs and to create a very substantial energy component of cost, this change (if adopted) must necessarily precipitate a change in PPL's distribution rate design philosophy.

For example, PPL's proposed rate design for the GS-3 and GH rate classes consists solely of a demand charge, based on the customer's peak demand within each month. This is based on the philosophy that costs for those classes are primarily demand-related. Under Mr. Galligan's proposal, a significant share of costs would be related to energy consumption. To be consistent with how costs are *allocated* to these classes, it would be necessary for PPL to modify its rate design proposal in order to recover a significant share of costs from an energy charge. Moreover, because the costs would be allocated to the class based on annual energy, the energy charge would need to be a flat energy charge that does not vary by time of day or by season.

A similar argument applies to the GS-1 rate design, although that class's rate design is even more complicated. Suffice it to say that PPL would likely need to reduce both its demand charge and its load-factor-blocked energy charges (in the "Wright tariff") and replace these reductions with a flat per-kWh energy charge.

Q. Are you able to quantify the magnitude of the impact of adopting Mr. Galligan's COSS on commercial class rate design?

A. Unfortunately I am not. The simulation of the COSS upon which Mr. Galligan relies does not fully classify costs into energy, demand and customer components. Instead, it appears to lump energy-related and customer-related costs into the same category, thereby rendering it useless for rate design purposes. Because of time and budget constraints, and because I do not recommend the adoption of Mr. Galligan's COSS, I have not attempted to fully classify all of the allocated costs in his COSS to provide a specific, quantitative response to this question.

Q. If the Commission adopts Mr. Galligan's proposal, in whole or in part, what would you recommend regarding commercial class rate design?

A. If the Commission does adopt Mr. Galligan's proposal, it will have no commercial or industrial class rate design proposals before it that are consistent with that methodology. Because adopting Mr. Galligan's proposal would represent a radical departure from past practice, I would recommend that the Commission re-open the proceeding for the purpose of rate design, particularly for the commercial (GS-1, GS-3, and GH) and industrial (LP-4) rate classes. In any such re-opened proceeding, PPL would be given an opportunity to propose an alternative rate design based on the new cost allocation methodology. Parties would be allowed to respond if they disagree with PPL's new proposal.

3. OCA Universal Service Cost Allocation Proposal

Q. Mr. Colton indicates that he has been informed by counsel that the matter of the allocation of universal service cost responsibility is "pending on appeal at this time." Is your understanding consistent with that of Mr. Colton?

A. Yes it is, based on the advice of counsel. I am also aware that the Commission explicitly directed that universal service costs be allocated only to the residential class in PPL's 2004 base rates proceeding. It ruled:

> *We will deny the Exceptions of the OCA and Mr. Epstein. Universal service programs, by their nature, are narrowly tailored to the residential customers and therefore, should be funded only by the residential class. We note that neither the OCA nor Mr. Epstein have presented any concrete evidence in the form of costs studies to support their respective proposals that the universal service program cost should be more broadly allocated. Accordingly, we will adopt the ALJ's recommendation on this issue.*[17]

In his testimony in the current proceeding, Mr. Colton offers no "concrete evidence in the form of cost studies" to justify alternative treatment of these costs. Therefore, it is unclear why Mr. Colton is raising this issue in this proceeding. Any change in the allocation of universal service costs should be deferred until the issue is resolved by the courts.

Q. Does Mr. Colton offer a specific proposal for how the Commission should allocate universal service costs among all rate classes?

A. No he does not. Moreover, any such allocation is a difficult problem. Even if Mr. Colton's argument that all rate classes benefit from the universal service programs were accepted, that argument does not provide any useful insight into how the universal service costs should be assigned between the residential and non-residential customer groups. Mr. Colton's argument also does not provide any useful guidance regarding how universal service costs should be assigned among the non-residential customer groups. If such benefits for non-residential customer classes were demonstrated to exist, it would be logical to assign the costs among the various customer classes in proportion to the benefits each class receives. However, Mr. Colton offers no quantitative assessment of

[17] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-00049255, order entered December 22, 2004, pages 97-98.

the relative benefits of the universal service programs among small and large business customers. He also does not provide any indication as to whether those benefits are related to energy consumption, peak demand, number of customers, total electric bill, total distribution bill, total revenues, total assets, or any other attribute of each customer.

Q. Mr. Colton argues that the Electricity Generation Customer Choice and Competition Act ("the Competition Act") requires that universal service costs be "non-bypassable," and that he interprets that to mean that all customers must contribute to paying for these costs. Is Mr. Colton's interpretation of the expression "non-bypassable" consistent with your experience with utility restructuring legislation?

A. No it is not. With the proviso that I am not an attorney, my experience with the concept of bypass in utility restructuring legislation is that "bypass" refers to the ability of a shopping customer to avoid paying for (i.e., to *bypass*) costs that customers who do not shop must pay. In this case, the most likely interpretation of the legislation is that the legislature did not want customers who would otherwise be required to pay for universal service costs to be able to bypass them by shopping. It makes little sense to me to interpret the provision to mean that customers who were previously not responsible for universal service costs must suddenly become responsible as a result of industry restructuring, rate unbundling, and competition for electricity supply.

Q. Mr. Colton appears to argue that commercial and industrial customer classes benefit more from industry restructuring than do residential customer classes, and therefore that the business customers must contribute to the expansion of universal service costs that were precipitated by restructuring. Do you agree with that logic?

A. No I do not. Mr. Colton offers no evidence that business customers have disproportionately benefited from industry restructuring or the ability to shop. In fact, my experience with the Pennsylvania Power Company suggests that the rate increases faced by industrial customers far outpaced the increases to the other rate classes, at the time prices transitioned to market.

In addition, while I am not an attorney, I do not find any language in the Act relating to the benefits of restructuring inuring primarily to business customers. I also do not find any language suggesting that an expansion of universal service benefits for residential customers was the *quid pro quo* for this alleged benefit to business customers. In fact, in several places, the Competition Act specifically states that competition is intended to benefit all rate classes. For example:

> *This Commonwealth must begin the transition from regulation to greater competition in the electricity generation market* ***to benefit all classes of customers*** *and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs.* (§2802(7), emphasis added)

> *The Commission shall require that restructuring of the electric utility industry be implemented in a manner that does not unreasonably discriminate against one customer class to the benefit of another.* (§2804(7))

Finally, I should also note that the percentage of customers who shop is not a reliable indicator of which customers are benefiting from industry restructuring. Even if residential and small commercial customers continue to take service from their EDCs through default service rates, they benefit from competition for default supply at the wholesale level. Under the Commission's final form default service regulations, such service must be competitively procured and supplied at prevailing market prices.

Thus, Mr. Colton's argument that businesses somehow disproportionately benefit from industry restructuring is simply wrong.

Q. Mr. Colton refers to PPL's Sustainable Development Program ("SDP") as an example of a benefit that is available only to business customers but that is paid for by all ratepayers, including residential customers. Is his example relevant for universal service cost funding?

A. I do not believe so. Utilities will often provide rate discounts or other benefits for "economic development" programs in order to expand their business bases to more efficiently use the distribution systems and thereby reduce the rates for all customers. In that way, the programs provide a hard economic benefit to all rate classes. Therefore, it is common that regulators require all ratepayers to contribute to the cost of the discounts.

If PPL cannot demonstrate that the additional load that it obtains (or retains) as a result of the Sustainable Development Program lowers the rates for all customer classes, the program should not be funded by ratepayers, either business or residential.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

EXHIBIT IEc-1R

REFERENCED INTERROGATORY RESPONSES

PPL-OSBA-I-1

OCA-PPL-V-16

OCA-PPL-V-17

Interrogatories of the PPL Electric Utilities Corporation to Office of Small Business Advocate Docket No. R-00072155

PPL-OSBA-I-1

Reference page 7, lines 3-6. Provide all empirical evidence relied upon to support the claim that it takes more poles, more transformers and more feet of conductor to serve one hundred 5 kW customers than to serve five 100 kW customers.

Response:

1. Mr. Knecht has not prepared any quantitative analysis of PPL Electric's distribution system. The referenced statement is based on the following logic. The number of poles and transformers, as well as conductor footage, are related to load density. It is unarguable that it requires more distribution equipment to serve 500 kW of load in a tight geographic location than to serve 500 kW of load spread out over a rural area. Thus, larger customers have proportionately less cost responsibility for distribution equipment for two reasons. First, simply by having a higher load in a single location, larger customers contribute less per kW to distribution cost causation than geographically separate smaller customers.

   By definition, a single load is more geographically dense than multiple loads. Second, larger business customers tend to be more concentrated than smaller residential customers, particularly in suburban and rural areas. PPL Electric confirms this statement for its service territory, in its responses to OCA-V-16 and OCA-V-17. Because the smaller residential customers tend to be more rural and therefore in lower load density areas, they contribute more per kW of demand to distribution cost causation than larger business customers.

   Finally, Mr. Knecht has participated in only one rate proceeding in which an electric distribution company prepared an analysis that directly assigned individual distribution system components to the customers served by each component, and then using a sampling methodology. The results of that utility's "component analysis methodology" resulted in a significantly higher percentage of both primary and secondary distribution system costs being assigned to smaller residential customers than to larger commercial customers than was the case under a traditional "minimum system" approach.

   See Aquila Networks Canada Application No. 1250392, before the Alberta Energy & Utilities Board, 2002. The methodology was generally approved by the AEUB at Decision 2003-019.

Witness: Robert D. Knecht

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set V,
Dated May 21, 2007
Docket No. R-00072155

Q.16. For questions 16-18, a square mile means about a square mile. The exact locations of the requested square mile areas are not expected to be specified, but are left to the discretion of the responder, who is presumably familiar enough with PPL's service territory to distinguish in his/her own mind, which parts of PPL's area are typical, densely populated and sparsely populated. The description sought includes the types of customers to be found in the requested areas, and their numbers (ordinal, relative share, or a comparison to the customer makeup found in the other areas requested, will suffice), and a description of the kinds of distribution plant that would typify each area. Please describe anecdotally the typical PPL customer base and PPL facilities located in a typical square mile of service territory.

A.16. The Company's service territory covers approximately 10,000 square miles and is comprised of areas that can be described as urban (the most densely populated areas including, for example, the cities of Allentown, Harrisburg, and Scranton), suburban (such as the townships and boroughs immediately adjacent to the aforementioned cities), and rural (the least densely populated areas including farmland and state game lands). As of December 31, 2006, PPL Electric served a total of 1,377,750 customers; therefore, a typical square mile would include about 138 customers. Such an environment would be more rural than suburban and generally would consist of primarily residential customers. The Company's distribution facilities typically would consist of poles and overhead distribution conductors, pole-mounted transformers, overhead service drops, and meters. Facilities typically would follow a radial rather than a network configuration.

PPL *Electric Utilities Corporation*
Response to Interrogatories of the
Office of Consumer Advocate, Set V,
Dated May 21, 2007
Docket No. R-00072155

Q.17. Please describe anecdotally the PPL customer base and PPL's facilities in a square mile of the most densely populated portion of PPL's service territory.

A.17. The most densely populated portions of PPL Electric's service territory are urban areas typified by, for example, the cities of Allentown, Harrisburg, and Scranton. Such areas would exhibit a mix of residential, commercial, and industrial customers. The Company's distribution facilities are likely to include a mix of overhead and underground equipment connected in a network configuration. Premises are likely to include apartment buildings and commercial space that house multiple customers and multiple metered services.

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OSBA STATEMENT NO. 3

Hbg ~~PK~~ AUG 16 2007

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	Docket No. R-00072155
	:	
PPL ELECTRIC UTILITIES CORPORATION	:	

DOCUMENT FOLDER

Surrebuttal Testimony and Exhibits of

ROBERT D. KNECHT

DOCKETED SEP 7 - 2007

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Distribution Cost Allocation Methodology
Revenue Allocation
Commercial Class Rate Design
Energy Efficiency Rider

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AUG 17 2007

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Date Served: August 8, 2007
Date Submitted for the Record: ______________________

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

1 Introduction and Overview

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct and rebuttal testimony earlier in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My qualifications were attached as Exhibit IEc-1 to my direct testimony.

Q. What is the purpose of this testimony?

A. This testimony has two components. First, in its rebuttal filing, PPL Electric Utilities Corporation ("PPL" or "the Company") revised its original filing with respect to the overall revenue requirement, the revenue allocation among the various rate classes, and the proposed rates for each class of customers. This surrebuttal testimony therefore updates my direct testimony to respond to PPL's revised proposals. Second, I address the critiques of my direct testimony presented in the rebuttal testimony of the following witnesses:

- Pennsylvania Office of Consumer Advocate ("OCA") witness Mr. Richard A. Galligan, regarding cost allocation methodological issues;
- PP&L Industrial Customer Alliance ("PPLICA") witness Mr. Stephen J. Baron, regarding revenue allocation issues;
- PPL witness Mr. Oliver G. Kasper, with respect to the implications of PPL's proposed rate design for the GH-1 and GS-3 classes;
- PPL witness Mr. Douglas A. Krall with respect to revenue allocation, scaleback methodology, and PPL's proposed Energy Efficiency Rider ("EER").

Q. How is your surrebuttal testimony organized?

A. Section 2 addresses PPL's revised revenue allocation proposal, and responds to Mr. Krall's observations regarding my proposed "differential scaleback" methodology. Section 3 addresses Mr. Galligan's rebuttal testimony regarding the cost allocation methodology. Section 4 explains why Mr. Baron's rebuttal to my direct testimony is moot, in light of PPL's revised revenue allocation proposal. Section 5 addresses customer migration issues involving the GH-1 and GS-3 rate classes. Section 6 responds to Mr. Krall's assertions regarding the EER proposal.

2. PPL's Revised Revenue Allocation Proposal

Q. Please summarize the key changes to its original filing that PPL presented in its rebuttal testimony.

A. PPL's revised filing contains the following basic changes:

- PPL reduced its proposed revenue increase from $83.5 million to $77.0 million.

- Of this $6.5 million reduction in the revenue requirement, approximately $3.0 million is related to an upward restatement of current revenues. This $3.0 million increase in current revenues resulted from (a) setting current rates to be consistent with the settlement of the remand phase of PPL's last base rates proceeding (Docket No. R-00049255), and (b) updating the revenue annualization calculations.

- The remaining $3.5 million reduction results from PPL's proposed changes to depreciation and amortization expenses, as well as a modest reduction in working capital rate base. These decreases are partially offset by a proposed increase in the allowed rate of return from 8.36 percent to 8.43 percent.

- PPL updated its cost of service study ("COSS") at both the current and the new proposed rates, reflecting the aforementioned cost and revenue changes. This study is presented in Exhibit JMK-2A Revised.

- PPL modified its revenue allocation proposal to reflect the changes in current revenues, while maintaining its philosophy of trying to move all rate classes about halfway toward cost-based rates using the indexed rate of return metric.

- PPL modified the specifics of its proposed rate design to reflect the revised revenue allocation proposal, although the rate design philosophy remains consistent with its original filing.

Q. Please comment on PPL's revised COSS analysis.

A. It is my understanding that PPL intended to apply the same COSS methodology in its rebuttal filing as it did in its original filing, adjusted only for the changes to its proposed revenue requirement and to reflect rates that go into effect as a result of the settlement of the remand phase of PPL's last base rates proceeding.

Unfortunately, it appears that PPL made an inadvertent error in its COSS analysis. Exhibit JMK-2A (Revised) classifies all services costs as customer-related, whereas both Exhibit JMK-2 and Exhibit JMK-2A classified services costs as partly demand-related and partly customer-related. This error results in an over-allocation of costs to Rates RS and GS-1, and an under-allocation of costs to Rates RTS, GS-3 and GH. No other classes should be affected by this error, because services costs are related only to those five classes.

At this stage of this proceeding, I do not have sufficient time to prepare a full COSS analysis to correct this error. However, my calculations indicate that correcting this error will have only relatively modest implications for allocating the revenue increase among the rate classes in this proceeding. This testimony therefore addresses PPL's COSS figures as reported. I recognize that the COSS will need to be corrected in PPL's compliance filing, if the Commission chooses to rely on it for revenue allocation.

Q. Please comment on PPL's revised revenue allocation proposal.

A. PPL's revised revenue allocation proposal is conceptually similar to that in its original filing, in that it proposes to move rates approximately halfway toward allocated costs. To measure progress toward cost-based rates, PPL continues to rely on the indexed (or relative) rate of return metric. For example, at current rates, Exhibit JMK-2A (Revised) indicates that the GS-1 rate class exhibits an indexed rate of return of 198 percent.[1] At PPL's proposed rates, the GS-1 indexed rate of return is 150 percent. Because an indexed rate of return of 100 percent implies revenues that are exactly equal to allocated costs,

[1] The indexed rate of return metric is calculated as the ratio of a class's rate of return to the system average rate of return. For GS-1, the class rate of return at current rates is 12.6 percent, compared to system average 6.35 percent, yielding a 1.98 or 198 percent indexed rate of return (12.6% divided by 6.35% = 1.98).

PPL's proposal moves the GS-1 class about halfway, going from 198 percent to 150 percent.[2]

In addition to its cost criteria, PPL's proposal incorporates the principle of rate gradualism, by constraining the percentage increases for rate classes to be no more than twice the system average increase.

The primary change in PPL's proposal is that the "current rates" starting point for calculating indexed rates of return is different. The adjusted current rates are now based on the settlement in the remand phase of PPL's last base rates proceeding. As I explained in my direct testimony, some of the rate adjustments that PPL proposed in its filing in *this* proceeding were achieved in the remand phase of the *last* proceeding, particularly for some large industrial rate classes. Therefore, the rate reductions that PPL had proposed in its direct testimony for some large industrial classes, notably Rates LP-5 and LP-6, are significantly adjusted in the Company's rebuttal filing.

Table IEc-S1 below shows the differences in the proposed rate increases for all of PPL's rate classes, between PPL's original filing and the rebuttal proposal.

In addition to the reductions in the proposed rate decreases for LP-5 and LP-6, Table IEc-S2 demonstrates that PPL now proposes to assign a lower rate increase to the GS-1 class. As I noted in my direct testimony, in PPL's original filing the GS-1 class made the least progress toward cost-based rates of all of the major distribution rate classes. PPL has presented a more balanced proposal in its rebuttal testimony.

Note also that PPL's filing shows the rate increase for the GS-3 class shifting from positive to negative. This change is likely the result of PPL's COSS error, which should

[2] Arithmetically, progress toward cost-based rates using the indexed rate of return is measured as the ratio of the change in the indexed rate of return between current and proposed rates to the difference between the current-rates indexed rate of return and one hundred percent. For example, suppose a rate class has an indexed rate of return at current rates of 160%. To completely get to cost-based rates, that class needs to reduce its indexed rate of return by 60% (i.e., the 160% minus 100%). Suppose further that the class exhibits an indexed rate of return at proposed rates of 145 percent. That class will exhibit progress that is equal to the change in the indexed rate of return of 15% (160%-145%) divided by the 60% change needed to achieve cost-based rates. The progress in this example is therefore 25% (15/% divided by 60%).

be corrected. However, my calculations indicate that correcting PPL's error would result in the need for only a relatively modest adjustment to its revenue allocation proposal for GS-3 customers. I estimate that if the GS-3 rate increase were set back to PPL's original proposal, at about a $600,000 rate increase rather than the $900,000 decrease, the progress toward cost-based rates would be consistent with PPL's goal to move rates halfway to allocated cost.

Table IEc-S1
PPL Proposed Revenue Increases
$000

	Original Proposal	**Rebuttal Filing**
RS	77,329	72,507
RTS	944	999
GS-1	845	198
GS-3	612	(932)
LP-4	(391)	(339)
ISP	(107)	(125)
LP-5	(135)	5
IST	(127)	(89)
LP-6	(5)	9
LPEP	(1)	(7)
ISA	6	0
GH	542	541
SL/AL	4,007	4,213
L5-S	2	0
Total	**83,521**	**76,980**

Note: Revenue increases include rate and other revenues.
Sources: Exhibit JMK-2A, Exhibit JMK-2A (Revised)

Q. In your direct testimony, Mr. Knecht, you proposed several adjustments to PPL's originally filed revenue allocation proposal, in order to reflect the revised starting point revenues resulting from the settlement of the remand proceeding. Mr. Krall indicates that PPL generally agrees with your findings, and that he believes that the revised revenue proposal will address your concerns. Is he correct?

A. Yes he is. While I continue to believe that the indexed rate of return metric overstates progress toward cost-based rates, I believe that PPL's revised proposal makes reasonable progress for all rate classes, consistent with the constraints of gradualism. I have updated my analysis of PPL's proposal in Exhibit IEc-S2, Schedule A, which shows progress toward cost-based rates using a variety of metrics. As that exhibit shows, while the reported progress toward cost-based rates is lower using alternative metrics, the progress is significant.

I therefore withdraw my proposal to adjust PPL's revenue allocation proposal to reflect the impact of adopting the remand settlement rates. If PPL is awarded its full proposed increase of $77.0 million, I recommend that the Commission adopt PPL's revenue allocation proposal. However, I also recommend that PPL's analysis be corrected for its COSS error.

To address the error, I recommend that the Commission approve PPL's revenue allocation *methodology*. I further recommend that the Commission direct PPL to correct the COSS error in its compliance filing, and to submit a corrected revenue allocation proposal based on the *methodology* presented in its rebuttal testimony.

Q. Suppose PPL is not awarded the full $77.0 million and that a scaleback of the revenue allocation is required. Please describe PPL's scaleback proposal.

A. PPL proposes to adopt a "***modified proportional scaleback***" methodology. In the normal "***proportional scaleback***" methodology, each class's rate increase at the full revenue requirement is scaled back in proportion to the reduction in the overall rate increase. For example, suppose the Commission reduced PPL's proposed $77.0 million increase by $20.0 million, to $57.0 million. Under the ***proportional scaleback*** approach, each class's revenue increase at the full revenue requirement would be reduced by the factor of $57.0 million divided by $77.0 million, or 74.0 percent. Under this approach, for example, the proposed increase for the RS class would be reduced from $72.5 million to $53.7 million ($72.5 times 74.0 percent = $53.7).

However, this approach is not reasonable in a case where rate decreases are proposed. If the ***proportional scaleback*** is applied to a class that is assigned a rate decrease, that class's rates will actually be *higher* as a result of a reduction in the overall revenue requirement. For example, if a rate class was assigned a $5.0 million rate decrease at the full revenue requirement, it would see only a $3.7 million rate decrease after the scaleback. Its rates would therefore have *increased* by $1.3 million. Under those conditions, an adjustment of some kind is necessary.

In the Company's ***modified proportional scaleback***, PPL proposes to give those classes that are assigned a rate decrease at the full revenue requirement the same dollar rate decrease at the reduced revenue requirement. For example if a rate class is assigned a $5.0 million rate decrease at the full revenue requirement, it is assigned a $5.0 million rate decrease at the reduced revenue requirement. Therefore, classes that are initially assigned a rate reduction would neither benefit from nor be harmed by a reduction to the overall revenue requirement. Under PPL's proposal, a proportional adjustment would then be applied to all of the other rate classes.[3]

Q. Do you agree with PPL's approach?

A. No. As I stated in my direct testimony, PPL's approach will reduce the progress toward cost-based rates that is built into the original proposal. Thus, PPL's modified proportional scaleback will make it much harder for the Company to achieve its goal of setting rates at or near allocated cost in the next base rates proceeding.

For example, as shown in Exhibit IEc-2S, Schedule A, PPL's proposed progress toward cost-based rates for the GS-1 rate class at the full revenue requirement is about 49 percent, with the indexed rate of return falling from 198 percent to 150 percent. However, if the Commission reduces PPL's rate increase by $20.0 million and applies PPL's modified proportional scaleback, the GS-1 indexed rate of return declines from 198 percent to 160 percent. Thus, rather than moving halfway toward cost-based rates, the modified proportional scaleback reduces the progress to less than 40 percent. My

[3] Under the PPL modified proportional scaleback, the percentage adjustment factor would be calculated only for those rate classes that do not face a rate increase. Thus, the total rate increase for classes with no decreases is $78.5 million, and the adjustment factor would be ($78.5 - $20.0)/$78.5 = 74.5%.

analysis of the implications of PPL's modified proportional scaleback proposal for all rate classes is shown in Exhibit IEc-S2, Schedule C.

Q. Mr. Krall complains that your proposal "gives additional rate decreases to classes that are already receiving rate decreases under the Company's proposal." He also indicates that, under the mechanics of the proposal, residential customers "will pay a greater percentage of the rate increase as the total increase is reduced." Please comment on his arguments?

A. Mr. Krall's rebuttal testimony fails to recognize PPL's basic goal of revenue allocation that is laid out in his direct testimony. In his direct testimony, Mr. Krall indicates that it is PPL's goal to move rate class revenues into line with allocated costs in two rate proceedings, including this one. Thus, when evaluating alternative scaleback methodologies, it is important to assess whether the approach is consistent with PPL's overall goal. Neither of Mr. Krall's calculations addresses this issue, nor does either calculation provide a credible reason for rejecting my proposal.

Let me turn to Mr. Krall's first observation. While it is arithmetically true that my proposal would assign a larger rate decrease to those rate classes that are originally assigned a rate decrease, there is no reason why that should not be the case. At PPL's full revenue requirement proposal, each class's rate increase or decrease is based on the costs allocated to it under the full revenue requirement. If PPL were to re-simulate its COSS model for, say, a lower rate of return, the costs allocated to each rate class will decline, *including the costs allocated to the rate classes that are assigned a rate decrease*. Under my proposal, that cost reduction will be reflected in lower rates for all rate classes.[4] Under PPL's proposal, the classes who are assigned a rate decrease will recognize none of the benefits of the lower allocated costs in their rates. PPL's proposal is therefore not consistent with either cost causation or with the principle of fairness.

Turning to Mr. Krall's second observation, he is again arithmetically correct that my proposal will result in the residential class bearing an increased share of the overall rate

[4] As a technical matter, I exclude the ISA rate class from the adjustment. As Mr. Krall testifies, that class is subject to contract rates.

increase. However, there is nothing magical about each class's share of the rate increase. PPL did not originally develop each class's rate increase by looking at the class share of the overall increase. ***PPL developed its proposal based on the goal of moving rates halfway toward allocated costs.*** Each class's share of the increase is not an *input to* that calculation; it is an *output of* the calculation. Had PPL proposed a lower overall revenue requirement in its original filing, its own goals would have required it to assign a larger share of the overall increase to the residential class.

My differential scaleback approach is therefore designed to better approximate what PPL's own methodology would have achieved had the Company proposed the lower revenue requirement. The PPL modified proportional scaleback methodology, by contrast, fails to accomplish PPL's stated goals.

Q. Can you update the example in your direct testimony of how the differential scaleback mechanism would work?

A. My calculations are presented in Exhibit IEc-2S, Schedule B. In that example, I assume (for illustrative purposes) that PPL's revenue increase is reduced by $20.0 million, from $77.0 million to $57.0 million. As shown in the exhibit, the effect of such a dollar reduction would reduce the system-wide average percentage increase from 11.4 percent to 8.4 percent, a reduction of 3.0 percent.

To implement the differential scaleback, I then apply that 3.0 percent reduction to each class's proposed increase at the full revenue requirement. For example, the RS class increase of 17.4 percent is reduced to 14.4 percent, and the GS-1 rate increase is reduced from +0.3 percent to -2.7 percent. All classes therefore share in the reduction on a comparable basis.

Note also that my approach retains much of the progress toward cost-based rates that was present in PPL's original proposal. For example, under PPL's full requirements proposal, the GS-1 indexed rate of return drops from 198 percent to 150 percent implying progress of 49 percent. Under PPL's modified proportional scaleback, as I noted earlier, the reduction in GS-1 indexed rate of return is from 198 percent to 160 percent, or about 39 percent progress. Under the differential scaleback, the GS-1 indexed rate of return drops from 198 percent to 153 percent, thereby retaining most of the progress that was built into PPL's original proposal.

3. Cost Allocation Methodology; OCA Witness Galligan

Q. Mr. Galligan begins his rebuttal testimony by asserting that you support PPL's distribution cost classification approach, that "is based on the assumption that roughly 60 percent of PPL's lines, poles, and transformer distribution plant and related costs are incurred to provide a 'connection service' and allocates these costs on a customer basis." Is his assertion correct?

A. No it is not. First, Mr. Galligan has his numbers wrong. PPL's distribution plant is classified as approximately 40 percent customer-related, not 60 percent customer-related as Mr. Galligan testifies.[5] Second, my cost classification recommendations are not based on the assumption that PPL provides a "connection service." It is my testimony that PPL needs to connect every customer to the system to provide service, and that therefore a portion of the costs are *causally related* to the number of customers attached to the system. Third, the customer component in PPL's methodology is not assumed. It is calculated using a generally accepted cost classification methodology.

Q. Mr. Galligan asserts that the NARUC Electricity Cost Allocation Manual ("the Manual") does not require that distribution costs be classified with a customer component. Is his testimony accurate?

A. No it is not. As a general rule, the Manual is reasonably careful to lay out the various methodologies in use for allocating all types of electric utility costs, including generation, transmission, and distribution costs. However, regarding the specific distribution cost classification methodologies that are in use, the Manual makes a specific conclusion with respect to cost classification. As the quote presented in Mr. Baron's rebuttal testimony indicates, the Manual asserts that distribution costs should be classified into both demand-related and customer-related components, and that the utility must develop a method for classifying costs into those categories.

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[5] If substation costs are excluded, the customer component is approximately 45 percent of distribution costs. It is possible that Mr. Galligan was referring to *secondary* distribution costs, although his testimony does not say so.

Q. Mr. Galligan asserts that the Manual provides for classification of distribution costs as partly energy-related, in addition to demand-related and customer-related. Can you comment on his assertion?

A. As shown in the attachment to Mr. Baron's rebuttal testimony (Exhibit SJB-1R), the Manual contains a full chapter regarding the classification and allocation of distribution costs in an embedded cost allocation study. That chapter indicates clearly that costs should be classified into demand and customer-related components. It also indicates that demand-related costs should be allocated using peak demand allocators. The chapter itself does not recognize any form of energy-classification for distribution costs.

However, Mr. Galligan is technically correct that the Manual's summary chapters do suggest that distribution costs may be partially energy-related. The only justification for such a classification approach that I can locate in the Manual is the following:

> *The costs of transmission and subtransmission are generally considered fixed costs that do not vary with the quantity of energy transmitted. However, to the extent that transmission investment enables a utility to avoid line losses, some portion of transmission may be classified as energy related. . . . The costs of electric distribution systems are affected primarily by demand and by the number of customers. As in transmission, it may be possible to identify some energy component of the cost.*[6]

Note, of course, that this quote also confirms the Manual's conclusion that some distribution costs should be classified as customer-related. Moreover, the Manual confirms that the "primary" cost classifications are demand-related and customer-related. In contrast, the Manual provides no justification for the very large energy component of distribution costs that Mr. Galligan advocates.

Q. Mr. Galligan indicates, "The NARUC Manual includes the customer classification of costs that Messrs. Knecht, Baron and Kincel prefer, as well as the energy classification that I advocate, in its discussion of major costing methodologies." Is Mr. Galligan's Peak-and-Average ("P&A") methodology consistent with the

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[6] "Electric Utility Cost Allocation Manual," National Association of Regulatory Utility Commissioners, 1992, page 21.

Manual's reference to setting an energy component of costs based on avoiding line losses?

A. No it is not.

First, Mr. Galligan's P&A approach has no customer component, as the Manual specifies. While I do not advocate it, it would certainly be possible to classify PPL's distribution costs into a customer component and a demand component, and then allocate the demand component using an allocator that reflects both demand and energy. This approach would then be consistent with the Manual's conclusion that distribution system costs do contain a customer component. Mr. Galligan has not adopted this approach.

Second, unlike the Manual, the P&A methodology is not grounded in the idea of avoided line losses. Mr. Galligan indicates that the P&A approach is based on the idea that no customer would take service without receiving energy. As I discussed in my rebuttal testimony, that idea is not consistent with the principle of cost causation. It is also not consistent with the Manual's hypothesis that any energy component of distribution costs should be related to avoided line losses.

Third, neither PPL nor Mr. Galligan has prepared any analysis that shows what the avoided energy costs associated with the hypothetical savings in line losses are, if any. Mr. Galligan arbitrarily assumes that 50 percent of the distribution costs are energy-related. He has made no showing that *any* costs are related to avoiding line losses, much less 50 percent of all distribution system costs.

Fourth, even if an energy component of distribution could be determined, Mr. Galligan's energy allocator would not be the correct allocation method. In the P&A approach, Mr. Galligan uses an *annual* energy allocator for assigning energy-related costs. When applied to the costs that are associated with avoiding line losses costs, Mr. Galligan's allocator would assume that a reduction in losses in a peak hour has the same value as a reduction in losses in an off-peak hour. This assumption is incorrect for two reasons. First, line loss rates tend to be higher during peak periods, implying that any reductions in line losses would have a greater impact on peak demands. Second, the value of line loss energy savings are higher during peak periods, because the market price for energy is higher during peak periods. If Mr. Galligan were to follow the Manual's suggestion and develop an energy component of distribution costs based on avoided line losses, he would then need to develop a time-of-use energy allocator to reflect the value of those savings during different time periods. Mr. Galligan has made no such calculations.

For those reasons, I conclude that the Manual is in no way consistent with Mr. Galligan's proposed approach.

Q. Is Mr. Galligan's P&A method recognized by the Manual as a standard method for classifying and allocating distribution costs?

A. No it is not.

Q. Has Mr. Galligan provided any evidence from Professor Bonbright's text that explicitly supports the use of a P&A allocator?

A. No he has not.

Q. Mr. Galligan also provides a quotation from <u>Gas Rate Fundamentals</u> in support of his assertion that only meters and services costs are customer-related, and that no part of the distribution system is cutomer-related. Can you comment on this reference?

A. Mr. Galligan's reliance on the AGA text is misplaced, because that text explicitly rejects his conclusion that distribution costs have no customer component. Simply adding the next sentence from that text to Mr. Galligan's quote yields the following:

> *The closer a plant item (e.g., a meter and service line) is located to a customer the more that particular item is related to the specific requirements of that customer.* ***Thus, the customer component of distribution costs reflects the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions.*** (emphasis added)[7]

In contrast to Mr. Galligan's assertion, PPL's method is entirely consistent with setting the customer component of distribution costs at the theoretical distribution system at

[7] <u>Gas Rate Fundamentals</u>, Fourth Edition, American Gas Association, 1987, page 136.

minimal load conditions. It is Mr. Galligan's P&A approach that is hopelessly inconsistent with both Gas Rate Fundamentals and with the NARUC Manual.

Q. Mr. Galligan's rebuttal also presents various reasons why primary distribution costs should not be classified as customer-related, including a quote from Professor Bonbright's text. Can you respond to his rebuttal testimony?

A. First, it is important to recognize that neither PPL nor any party to this proceeding has recommended that primary distribution system costs be classified as both customer-related and demand-related. Therefore, Mr. Galligan's assertions are not particularly relevant.

Second, while Professor Bonbright's text may not agree, it is relatively common for electric utilities to classify both secondary and primary system costs (excluding substations) as both customer-related and demand-related. To interconnect all customers, utilities will often need to extend the primary distribution system as well as the secondary distribution system, particularly in rural areas. Therefore, it is not unreasonable to hypothesize that primary distribution costs have a customer component as well as a demand component. In addition, the Manual explicitly refers to developing classification splits separately for both primary and secondary system costs.[8]

Thus, in contrast to Mr. Galligan's portrayal of it as an extreme approach, PPL's approach is a compromise approach. It recognizes that a customer component of costs exists for the secondary distribution system, but it does not attempt to derive a customer component in the primary system.

Q. Can you summarize your reasons why PPL's cost classification methodology is superior to Mr. Galligan's P&A approach?

A. My reasons are as follows:

[8] See, for example, page 93. In addition, the Manual does not state that it is necessary to segregate primary voltage system costs from secondary voltage system costs for minimum system calculations, except to recognize that substation costs are generally all demand-related.

- To provide service, PPL must meet its customers' peak demands and it must interconnect all of the customers. Distribution costs are therefore causally related to both peak demand and the number of customers.

- The authorities consistently support the classification of costs into customer-related and demand-related components. These authorities include NARUC's "Electric Utility Cost Allocation Manual," AGA's Gas Rate Fundamentals, and Bary's Operational Economics of Electric Utilities. None of these authorities supports the P&A Method.

- Bonbright's Principles of Public Utility Rates appears to oppose the classification of costs as partly customer-related, but does not offer a credible alternative for embedded cost allocation. In addition, the conclusion in that text is based on a flawed and irrelevant statistical study involving rural electric utilities. Moreover, Professor Bonbright admits that most utilities classify distribution costs into demand and customer components. Finally, Professor Bonbright's text does not support the P&A methodology advocated by Mr. Galligan.

- PPL's methodology has been used for many years, it has been explicitly approved by the Commission, and it is the basis for PPL's proposed commercial and industrial class rate design in this proceeding.

4. Revenue Allocation; PPLICA Witness Baron

Q. Mr. Baron opposes your proposal for first dollar relief for the Rate GS-1 class, indicating that PPL did not submit a revised revenue allocation and rate design proposal. Please respond to Mr. Baron's argument.

A. Mr. Baron's complaint is moot. In its rebuttal filing, PPL has made a revised revenue allocation and rate design proposal. Moreover, as PPL witness Mr. Krall suggested, PPL's modifications did address my concerns with respect to class revenue allocation and the implications of the remand settlement. As stated above, I have therefore withdrawn my proposal for first dollar relief for the GS-1 class.

5. Commercial Class Rate Design; PPL Witness Kasper

Q. In your direct testimony, you concluded that some customers who are currently served under PPL's proposed Rate GH-1 may be eligible for lower overall utility bills under PPL's proposed Rate GS-3. Mr. Kasper indicates that PPL will not make any recommendations to those customers regarding which service to choose. Can you respond to Mr. Kasper's rebuttal?

A. First, I note that Mr. Kasper does not dispute that some GH-1 customers may be able to achieve lower bills under Rate GS-3. Second, I did not testify that PPL should *make a recommendation* to GH-1 customers. I testified that PPL should *notify* those customers that they may be able to obtain lower rates under GS-3 service.

Mr. Kasper testifies that "PPL Electric would be willing to prepare rate comparisons for all customers currently taking service on Rate Schedule GH-1 who qualify to take service [on] Rate Schedule GS-3, to show the current rate differences based upon their prior year's usage." While it appears that Mr. Kasper agrees with me, this statement is a little ambiguous about whether PPL will actually provide the results of its analysis to the GH-1 customers. It is my understanding that PPL has an obligation to reasonably inform its customers of their options with respect to taking service under alternative tariffs. I therefore recommend that the Commission direct PPL to provide the results of its analysis to the GH-1 customers, if PPL does not agree to do so voluntarily.

Q. Mr. Kasper testifies that the PPL revenue requirement should be increased by the $670,000 in revenue loss associated with customers converting to GS-3 from GH-1 service. Do you agree with Mr. Kasper's recommendation?

A. No I do not, for two reasons.

First, my recommendations regarding notifying customers were based on *PPL's proposed rates*, not my proposed rates. PPL was presumably aware when it prepared its filing that it was proposing distribution rates for GH-1 customers that exceeded GS-3 rates, and that some GH-1 customers may be able to achieve lower overall bills by switching. It therefore had ample opportunity to evaluate the potential customer migration from GH-1 to GS-3 service.

Second, I am advised by counsel that PPL has the burden of proof with respect to justifying its revenue requirement. For PPL to claim that it is entitled to additional revenue related to customer migration, the Company must provide reasonable evidence about how many customers and how much load would switch. PPL has made no such demonstration.

Q. Why is Mr. Kasper's calculation of lost revenue of $670,000 not a reasonable calculation of the impact?

A. Mr. Kasper's $670,000 figure is substantially overstated for two reasons. First, Mr. Kasper's calculation is based on the assumption that the entire GH-1 load would convert to GS-3 service. This assumption is unsubstantiated for the following reasons:

- It is inconsistent with Mr. Kasper's own testimony, since he indicates that only GH-1 customers with polyphase service will be allowed to convert to GS-3. Mr. Kasper provides no evidence about the magnitude of the GH-1 load that currently takes single versus polyphase service.

- Mr. Kasper indicates that "TOD" GH-1 customers will not be eligible for GS-3 TOD service. Therefore, GH-1 TOD customers may be better off staying on PPL's proposed GH-1 TOD service than by converting to regular GS-3 service. Mr. Kasper provides no analysis of the impact of this effect on each customer's decision as to whether to migrate.

- Even if they face higher distribution rates, some GH-1 customers are likely to be able to obtain lower overall bills under GH-1 service relative to GS-3, due to differences in the electricity supply charges.[9] Mr. Kasper provides no analysis of the differences in

[9] These charges include PPL's Energy & Capacity charges, the Competitive Transition charges, and the Intangible Transition charges. As I demonstrate in my direct testimony, the average electricity supply rates for GS-3 and GH-1 service are about the same. However, because the tariff design for GH-1 is very different from GS-3, there are likely to be much larger differences for individual customers.

electricity supply rates that would also affect each customer's decision about whether to migrate to GS-3 service.

Second, Mr. Kasper appears to have used the wrong demand charges in his analysis, in that he used the demand charges as proposed in PPL's original filing. Mr. Kasper's updated rate design proposal would result in a lower lost revenue figure, even if total customer migration were assumed.

For that reason, I do not agree that PPL has met its burden of proof with respect to this particular revenue requirement item.

6. Energy Efficiency Rider ("EER"); PPL Witness Krall

Q. In your direct testimony, you recommended that the Commission "limit [EER] recovery to the $2.7 million identified by PPL in this proceeding, by either including these costs in base rates on a non-reconcilable basis or by setting a cap on the reconcilable amounts." Mr. Krall indicates that such a proposal "might be appropriate if the scope of consumer education and programs were fully known." Is his critique reasonable?

A. I do not believe so. In fact, it is exactly because the scope of potential activities is not known that a cap should be set on the EER amount. Without such a cap, the Commission would be faced with two unpleasant alternatives.

The first alternative is that PPL would be granted a blank check for pursuing whatever "energy efficiency" programs that it wanted to undertake. As PPL has an economic *disincentive* to reduce energy consumption, I expect that, without oversight, PPL would be sorely tempted to focus on programs that provided public relations or other benefits to itself and its affiliates. For the reasons stated in my direct testimony, providing PPL with a capped amount of ratepayer funds to engage in vaguely-defined energy efficiency programs is already suspect. Eliminating regulatory controls entirely could result in significant waste.

The second alternative is that the Commission establishes an expensive and intrusive reconciliation review process, to ensure that the EER costs are prudently incurred. Such a process would necessarily be litigious and costly. Also, it would likely provide a forum for various parties to provide a wide range of energy efficiency proposals, and for other parties to voice all of their complaints about PPL's choices. In light of the relatively small magnitude of the costs involved, I do not believe this approach would be cost-effective.

In my view, the efficacy of PPL's efforts should be evaluated in PPL's next base rates case. Combined with a cap on the overall spending amount that is included in rates, this approach will provide much better incentives for PPL to operate these programs effectively and efficiently.

Q. Mr. Krall indicates that the EER program targeted at RTS customers may potentially help commercial customers, and that the RTS program comprises only 16 percent of the estimated $2.7 million in costs. Are those reasons sufficient to reject your recommendation that an EER program, if approved by the Commission, be rate class specific?

A. I do not believe so, for three reasons.

First, I note that PPL proposes to assign the EER to the RS, RTS, RTD, and GS-1 rate classes as a percentage of distribution revenues. According to page 6 of Attachment 1 to PPL Rebuttal Statement No. 7-R, PPL intends to charge GS-1 customers with $471,000, or 16.6 percent of the $2.857 million estimated EER costs (including GRT). According to Exhibit JMK-2A Revised, GS-1 customers are responsible for 12.3 percent of the energy, 10.8 percent of the system peak demand and 10.8 percent of the number of customers for the RS, RTS, RTD, and GS-1 rate class group. Thus, to support his proposal, Mr. Krall needs to demonstrate why the commercial customers should be *disproportionately* paying for these programs. He provides no such evidence.

Second, PPL's programs are not defined particularly well at this stage. While Mr. Krall may opine that the "Time-of-Use Pricing for *Residential Thermal Storage* Customers Program" will somehow benefit commercial customers, he makes no specific analysis of what that benefit will be, or how much of it could possibly relate to commercial customers. Absent any better evidence, it must be concluded that a program so entitled will benefit RTS customers almost exclusively. I note also that, under any cost allocation study filed in this proceeding, RTS customers are already receiving substantial subsidies from the business rate classes, particularly from the GS-1 class. There is no need to exacerbate that problem with the EER.

Third, PPL has made no effort to evaluate whether EER programs would be as effective for commercial customers as they are for residential customers. In some ways, commercial customers are less flexible than residential customers, particularly with respect to reducing on-peak demands. For example, set-back thermostats may be effective in reducing residential class heating and cooling during peak periods of the day, when many residential customers are out of the house. However, many small business customers may not find it practical to adjust their thermostats during normal business hours, since the effect will be to make their customers and/or their employees uncomfortable. Thus, depending on the program, small business customers could end up paying for programs that are of no benefit to them.

For those reasons, I retain my conclusion that, if the Commission determines that an EER is in the public interest, it be made specific to each rate class.

Q. Does this conclude your surrebuttal testimony?

A. Yes it does.

EXHIBIT IEc-1S

REVENUE ALLOCATION EXHIBITS

Schedule A: PPL Proposed Revenue Allocation

Schedule B: IEc Proposed Scaleback Methodology

Schedule C: Implications of Modified Proportional Scaleback Methodology

Exhibit IEc-1S, Schedule A

PPL Distribution Revenue Allocation Proposal: Exhibit JMK-2A (Revised)

	Total	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
Current Rates (Remand Proceeding)															
Total Revenues	*676,582*	*416,704*	*4,630*	*78,035*	*115,930*	*30,988*	*1,880*	*1,389*	*615*	*36*	*360*	*547*	*6,773*	*18,658*	*37*
O&M Expenses	339,648	245,002	5,213	27,397	35,825	9,614	483	437	100	36	88	23	2,633	12,785	12
Dep'n/Amortization	109,647	73,038	1,987	10,059	14,296	3,582	179	323	85	30	57	20	1,136	4,845	10
Total Taxes	*98,916*	43,450	(1,232)	17,756	28,355	7,690	530	253	185	(15)	98	221	1,262	356	7
Return	*128,371*	*55,214*	*(1,338)*	*22,823*	*37,454*	*10,102*	*688*	*376*	*245*	*(15)*	*117*	*283*	*1,742*	*672*	*8*
Total Cost	676,582	471,112	11,449	57,262	80,178	21,260	1,064	1,057	261	98	241	50	5,990	26,529	33
Rate Base	2,020,327	1,335,498	37,413	181,070	282,895	75,577	3,830	3,070	818	292	819	189	20,699	78,063	94
Rate of Return	*6.35%*	*4.13%*	*-3.58%*	*12.60%*	*13.24%*	*13.37%*	*17.96%*	*12.25%*	*29.95%*	*-5.14%*	*14.29%*	*149.74%*	*8.42%*	*0.86%*	*8.51%*
Indexed RoR	100.0%	65.1%	-56.3%	198.4%	208.4%	210.4%	282.7%	192.8%	471.4%	-80.8%	224.8%	2356.6%	132.5%	13.5%	133.9%
Normalized R/C Ratio	100.0%	88.9%	40.1%	135.4%	141.9%	142.9%	172.8%	131.8%	235.4%	37.6%	148.2%	1072.3%	111.4%	70.5%	111.8%
Differential RoR	0.00%	-2.22%	-9.93%	6.25%	6.89%	7.01%	11.61%	5.89%	23.60%	-11.49%	7.93%	143.38%	2.06%	-5.49%	2.16%
Subsidy	-	(54,408)	(6,819)	20,773	35,752	9,728	816	332	354	(62)	119	497	783	(7,871)	4
PPL Proposed Rates															
Total Revenues	*753,562*	*489,211*	*5,629*	*78,233*	*114,998*	*30,649*	*1,755*	*1,394*	*526*	*45*	*353*	*547*	*7,314*	*22,871*	*37*
Total Revenue Incr.	*76,980*	*72,507*	*999*	*198*	*(932)*	*(339)*	*(125)*	*5*	*(89)*	*9*	*(7)*	-	541	4,213	-
Percent Revenue Incr.	11.4%	17.4%	21.6%	0.3%	-0.8%	-1.1%	-6.6%	0.4%	-14.5%	25.0%	-1.9%	0.0%	8.0%	22.6%	0.0%
O&M Expenses	340,264	245,572	5,215	27,423	35,840	9,615	483	438	100	36	88	23	2,634	12,785	12
Dep'n/Amortization	109,647	73,038	1,987	10,059	14,296	3,582	179	323	85	30	57	20	1,136	4,845	10
Total Taxes	133,339	75,856	(782)	17,843	27,943	7,540	474	254	144	(12)	94	221	1,505	2,252	7
Return	170,312	94,745	(791)	22,908	36,919	9,912	619	379	197	(9)	114	283	2,039	2,989	8
Total Cost	753,562	521,949	12,870	64,203	91,007	24,150	1,211	1,173	291	107	270	57	6,774	29,463	37
Rate Base	2,020,327	1,335,498	37,413	181,070	282,895	75,577	3,830	3,070	818	292	819	189	20,699	78,063	94
Rate of Return	*8.43%*	*7.09%*	*-2.11%*	*12.65%*	*13.05%*	*13.12%*	*16.16%*	*12.35%*	*24.08%*	*-3.08%*	*13.92%*	*149.74%*	*9.85%*	*3.83%*	*8.51%*
Indexed RoR	100.0%	84.2%	-25.1%	150.1%	154.8%	155.6%	191.7%	146.4%	285.7%	-36.6%	165.1%	1776.2%	116.9%	45.4%	101.0%
Revenue/Cost Ratio	*100.0%*	*93.7%*	*43.7%*	*121.9%*	*126.4%*	*126.9%*	*144.9%*	*118.8%*	*180.8%*	*42.2%*	130.5%	962.8%	108.0%	77.6%	100.4%
Differential RoR	0.00%	-1.34%	-10.54%	4.22%	4.62%	4.69%	7.73%	3.92%	15.65%	-11.51%	5.49%	141.31%	1.42%	-4.60%	0.08%
Subsidy	-	(32,738)	(7,241)	14,030	23,991	6,499	544	221	235	(62)	83	490	540	(6,592)	0
Progress Toward Cost-Based Rates															
Indexed RoR		55%	20%	49%	49%	50%	50%	50%	50%	24%	48%	26%	48%	37%	97%
Normalized R/C Ratio		43%	6%	38%	37%	37%	38%	41%	40%	7%	37%	11%	30%	24%	97%
Differential RoR		40%	-6%	32%	33%	33%	33%	34%	34%	0%	31%	1%	31%	16%	96%
Subsidy		40%	-6%	32%	33%	33%	33%	34%	34%	0%	31%	1%	31%	16%	96%

Exhibit IEc-1S, Schedule B															
PPL Distribution Revenue Allocation Proposal: IEc Scaleback Proposal															
	Total	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
Current Rates (Remand Proceeding)															
Total Revenues	***676,582***	***416,704***	***4,630***	***78,035***	***115,930***	***30,988***	***1,880***	***1,389***	***615***	***36***	***360***	***547***	***6,773***	***18,658***	***37***
O&M Expenses	339,648	245,002	5,213	27,397	35,825	9,614	483	437	100	36	88	23	2,633	12,785	12
Dep'n/Amortization	109,647	73,038	1,987	10,059	14,296	3,582	179	323	85	30	57	20	1,136	4,845	10
Total Taxes	98,916	43,450	(1,232)	17,756	28,355	7,690	530	253	185	(15)	98	221	1,262	356	7
Return	128,371	55,214	(1,338)	22,823	37,454	10,102	688	376	245	(15)	117	283	1,742	672	8
Total Cost	676,582	471,112	11,449	57,262	80,178	21,260	1,064	1,057	261	98	241	50	5,990	26,529	33
Rate Base	2,020,327	1,335,498	37,413	181,070	282,895	75,577	3,830	3,070	818	292	819	189	20,699	78,063	94
Rate of Return	6.35%	4.13%	-3.58%	12.60%	13.24%	13.37%	17.96%	12.25%	29.95%	-5.14%	14.29%	149.74%	8.42%	0.86%	8.51%
Indexed RoR	100.0%	65.1%	-56.3%	198.4%	208.4%	210.4%	282.7%	192.8%	471.4%	-80.8%	224.8%	2356.6%	132.5%	13.5%	133.9%
Normalized R/C Ratio	100.0%	88.8%	40.1%	136.6%	142.2%	143.4%	173.5%	133.4%	235.4%	37.6%	148.6%	1078.6%	111.7%	70.5%	111.6%
Differential RoR	0.00%	-2.22%	-9.93%	6.25%	6.89%	7.01%	11.61%	5.89%	23.60%	-11.49%	7.93%	143.38%	2.06%	-5.49%	2.16%
Subsidy	-	(54,408)	(6,819)	20,773	35,752	9,728	816	332	354	(62)	119	497	783	(7,871)	4
IEc Scaleback Rates															
PPL Revenue Increase	76,980	72,507	999	198	(932)	(339)	(125)	5	(89)	9	(7)	-	541	4,213	-
PPL % Revenue Incr.	11.4%	17.4%	21.6%	0.3%	-0.8%	-1.1%	-6.6%	0.4%	-14.5%	25.0%	-1.9%	0.0%	8.0%	22.6%	0.0%
Adjustment $	(20,000)														
Adjustment Percent	-3.0%														
Adj. Rev. Increase %	8.4%	14.4%	18.6%	-2.7%	-3.8%	-4.1%	-9.6%	-2.6%	-17.4%	22.0%	-4.9%	[illegible]	5.0%	19.6%	-3.0%
Adj. Rev. Increase	56,980	60,179	862	(2,111)	(4,362)	(1,256)	(181)	(36)	(107)	8	(18)	-	341	3,661	(1)
Total Revenues	***733,562***	***476,883***	***5,492***	***75,924***	***111,568***	***29,732***	***1,699***	***1,353***	***508***	***44***	***342***	***547***	***7,114***	***22,319***	***36***
O&M Expenses	339,913	245,475	5,215	27,120	35,895	9,618	483	430	100	36	88	23	2,634	12,785	12
Dep'n/Amortization	109,647	73,038	1,987	10,059	14,296	3,582	179	323	85	30	57	20	1,136	4,845	10
Total Taxes	124,350	70,315	(844)	16,805	26,402	7,128	449	236	136	(12)	89	221	1,415	2,004	7
Return	159,652	88,055	(866)	21,940	34,976	9,405	588	365	187	(10)	108	283	1,929	2,685	7
Total Cost	733,562	508,967	12,508	61,917	88,404	23,433	1,175	1,129	283	104	263	55	6,575	28,713	36
Rate Base	2,020,327	1,335,498	37,413	181,070	282,895	75,577	3,830	3,070	818	292	819	189	20,699	78,063	94
Rate of Return	***7.902%***	***6.59%***	***-2.32%***	***12.12%***	***12.36%***	***12.44%***	***15.36%***	***11.88%***	***22.86%***	***-3.28%***	***13.20%***	***149.74%***	***9.32%***	***3.44%***	***7.87%***
Indexed RoR	100.0%	83.4%	-29.3%	153.3%	156.5%	157.5%	194.4%	150.3%	289.3%	-41.5%	167.1%	1894.8%	117.9%	43.5%	99.6%
Revenue/Cost Ratio	100.0%	93.7%	43.9%	122.6%	126.2%	126.9%	144.6%	119.8%	179.3%	42.3%	130.3%	994.8%	108.2%	77.7%	99.8%
Differential RoR	0.00%	-1.31%	-10.22%	4.21%	4.46%	4.54%	7.46%	3.97%	14.96%	-11.19%	5.30%	141.83%	1.42%	-4.46%	-0.03%
Subsidy	-	(32,084)	(7,016)	14,007	23,164	6,300	524	224	225	(60)	80	492	538	(6,394)	(0)
Progress Toward Cost-Based Rates															
Indexed RoR		53%	17%	46%	48%	48%	48%	46%	49%	22%	46%	20%	45%	35%	101%
Normalized R/C Ratio		44%	6%	38%	38%	38%	39%	41%	41%	8%	38%	9%	30%	25%	101%
Differential RoR		41%	-3%	33%	35%	35%	36%	33%	37%	3%	33%	1%	31%	19%	102%
Subsidy		41%	-3%	33%	35%	35%	36%	33%	37%	3%	33%	1%	31%	19%	102%

Exhibit IEc-1S, Schedule C

PPL Distribution Revenue Allocation Proposal: Implications of Modified Proportional Scaleback

	Total	RS	RTS	GS-1	GS-3	LP-4	ISP	LP-5	IST	LP-6	LPEP	ISA	GH	SL/AL	L5-S
Current Rates (Remand Proceeding)															
Total Revenues	***676,582***	***416,704***	***4,630***	***78,035***	***115,930***	***30,988***	***1,880***	***1,389***	***615***	***36***	***360***	***547***	***6,773***	***18,658***	***37***
O&M Expenses	339,648	245,002	5,213	27,397	35,825	9,614	483	437	100	36	88	23	2,633	12,785	12
Dep'n/Amortization	109,647	73,038	1,987	10,059	14,296	3,582	179	323	85	30	57	20	1,136	4,845	10
Total Taxes	98,916	43,450	(1,232)	17,756	28,355	7,690	530	253	185	(15)	98	221	1,262	356	7
Return	128,371	55,214	(1,338)	22,823	37,454	10,102	688	376	245	(15)	117	283	1,742	672	8
Total Cost	676,582	471,112	11,449	57,262	80,178	21,260	1,064	1,057	261	98	241	50	5,990	26,529	33
Rate Base	2,020,327	1,335,498	37,413	181,070	282,895	75,577	3,830	3,070	818	292	819	189	20,699	78,063	94
Rate of Return	***6.35%***	***4.13%***	***-3.58%***	***12.60%***	***13.24%***	***13.37%***	***17.96%***	***12.25%***	***29.95%***	***-5.14%***	***14.29%***	***149.74%***	***8.42%***	***0.86%***	***8.51%***
Indexed RoR	100.0%	65.1%	-56.3%	198.4%	208.4%	210.4%	282.7%	192.8%	471.4%	-80.8%	224.8%	2356.6%	132.5%	13.5%	133.9%
Normalized R/C Ratio	100.0%	88.8%	40.2%	135.6%	142.5%	143.6%	173.7%	131.8%	235.7%	37.6%	148.7%	1079.3%	111.8%	70.5%	111.6%
Differential RoR	0.00%	-2.22%	-9.93%	6.25%	6.89%	7.01%	11.61%	5.89%	23.60%	-11.49%	7.93%	143.38%	2.06%	-5.49%	2.16%
Subsidy	(0)	(54,408)	(6,819)	20,773	35,752	9,728	816	332	354	(62)	119	497	783	(7,871)	4
Proportional Scaleback Rates															
PPL Rev. Increase	76,980	72,507	999	198	(932)	(339)	(125)	5	(89)	9	(7)	-	541	4,213	-
PPL % Revenue Incr.	11.4%	17.4%	21.6%	0.3%	-0.8%	-1.1%	-6.6%	0.4%	-14.5%	25.0%	-1.9%	0.0%	8.0%	22.6%	0.0%
Adjustment $	(20,000)														
Scaleback Factor	74.5%														
Adj. Rev. Increase	56,980	54,027	744	148	(932)	(339)	(125)	4	(89)	7	(7)	-	403	3,139	-
Total Revenues	***733,562***	***470,731***	***5,374***	***78,183***	***114,998***	***30,649***	***1,755***	***1,393***	***526***	***43***	***353***	***547***	***7,176***	***21,797***	***37***
O&M Expenses	340,111	245,427	5,214	27,416	35,840	9,615	483	438	100	36	88	23	2,634	12,785	12
Dep'n/Amortization	109,647	73,038	1,987	10,059	14,296	3,582	179	323	85	30	57	20	1,136	4,845	10
Total Taxes	124,350	67,550	(896)	17,820	27,943	7,540	474	253	144	(13)	94	221	1,443	1,769	7
Return	159,454	84,716	(931)	22,887	36,919	9,912	619	379	197	(10)	114	283	1,963	2,398	8
Total Cost	733,562	508,702	12,502	62,405	88,216	23,404	1,174	1,143	283	104	262	55	6,571	28,704	36
Rate Base	2,020,327	1,335,498	37,413	181,070	282,895	75,577	3,830	3,070	818	292	819	189	20,699	78,063	94
Rate of Return	***7.892%***	***6.34%***	***-2.49%***	***12.64%***	***13.05%***	***13.12%***	***16.16%***	***12.33%***	***24.08%***	***-3.51%***	***13.92%***	***149.74%***	***9.49%***	***3.07%***	***8.51%***
Indexed RoR	100.0%	80.4%	-31.5%	160.1%	165.4%	166.2%	204.8%	156.2%	305.1%	-44.5%	176.4%	1897.2%	120.2%	38.9%	107.8%
Revenue/Cost Ratio	100.0%	92.5%	43.0%	125.3%	130.4%	131.0%	149.5%	121.9%	185.9%	41.1%	134.5%	995.4%	109.2%	75.9%	103.0%
Differential RoR	0.00%	-1.55%	-10.38%	4.75%	5.16%	5.22%	8.27%	4.44%	16.19%	-11.41%	6.03%	141.84%	1.59%	-4.82%	0.62%
Subsidy	-	(37,971)	(7,128)	15,777	26,782	7,245	581	250	243	(61)	91	492	605	(6,907)	1
Progress Toward Cost-Based Rates															
Indexed RoR		44%	16%	39%	40%	40%	43%	39%	45%	20%	39%	20%	38%	29%	77%
Normalized R/C Ratio		33%	5%	29%	29%	29%	33%	31%	37%	6%	29%	9%	22%	19%	75%
Differential RoR		30%	-5%	24%	25%	26%	29%	25%	31%	1%	24%	1%	23%	12%	71%
Subsidy		30%	-5%	24%	25%	26%	29%	25%	31%	1%	24%	1%	23%	12%	71%