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OSBA STATEMENT NO. 1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of PECO Energy Company For Approval Of Its Restructuring Plan Under Section 2806 Of The Public Utility Code	:	Docket No. R-00973953

Direct Testimony and Exhibit of

BRIAN KALCIC

Statement
OSBA EXHIBIT
DATE 10-14/15/16-97
MARY ELLEN WOLF, REPORTER
Philadelphia
R-00973953, etc.

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

Date Served: June 20, 1997

Date Submitted for the Record: _____

Direct Testimony of Brian Kalcic

Q. Please state your name and business address.

A. Brian Kalcic, 225 S. Meramec Avenue, St. Louis, Missouri 63105.

Q. What is your occupation?

A. I am an economist and consultant in the field of public utility regulation, and founder and principal of Excel Consulting. My qualifications are described in the Appendix to this testimony.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Office of Small Business Advocate (OSBA) which is representing small business customers served by PECO Energy Company (PECO).

Q. What is the subject of your testimony?

A. My testimony examines select topics in three areas. In the first section of my testimony, I discuss the uncertainty inherent in the Company's estimate of the market value of its generating units, and its implication for stranded cost determination. In the second part of my testimony, I examine the reasonableness of PECO's proposed methodology for allocating Competitive Transition Charge (CTC) costs among rate classes. Lastly, I critique PECO's proposed method for determining

eligibility to participate in the first two steps of the Phase-In to Direct Access within Rate GS.

To the extent that portions of my testimony and/or exhibit reflect PECO's claimed level of stranded costs, such correspondence is for comparison purposes only and should not be construed as acquiescence by the OSBA to the Company's position, in whole or in part.

Q. Please summarize your major findings and recommendations.

A. With respect to the estimated market value of PECO's generating units, I find that:

- PECO's proposal to utilize its lowest market value estimate for purposes of determining its stranded cost claim is unfounded and should be rejected;

- to date, the Company has not conducted a sufficient level of analysis with respect to testing the sensitivity of its market value estimates to changes in various model assumptions;

- a reasonable bound on the total level of stranded costs associated with PECO's net generating plant is therefore unknown at this time; and

- in the absence of a bounded assessment of the stranded costs associated with net generating plant, the Commission should implement a market value/stranded cost adjustment so as to implicitly share the risks associated with the uncertainty of future market price forecasts between customers and shareholders.

With respect to the Company's proposed CTC allocation methodology and Phase-In selection procedures, I find that:

- the Company's CTC allocator fails to recognize the energy-related nature of the Deferred Fuel portion of its stranded cost claim, and therefore an adjustment to PECO's proposed CTC allocation methodology is warranted;

- the Company's proposed Phase-In selection process for the commercial customer class is likely to result in smaller Rate GS customers being under-represented in the first two steps of the Phase-In; and

- accordingly, the Rate GS class should be divided for purposes of the Phase-In into a small and large

segments, with individual commercial customers selected on a "first-come-first-served" basis within each segment.

Market Value Estimates

Q. What portion of PECO's claimed level of stranded costs is attributable to net generating plant and associated CWIP?

A. As of December 31, 1998, PECO claims its stranded costs will total $6.8 billion, of which $3.8 billion would be attributable to net generating plant and CWIP. In particular, the $3.8 billion net plant/CWIP figure is comprised of approximately $6.7 billion in net generation investment less a $2.9 billion offset for the estimated market value of PECO's generating units.

Q. Please provide a brief overview of PECO's approach to estimating the present market value of its generating units.

A. To arrive at an estimate of the market value of its generating units, PECO attempts to calculate the net present value (NPV) of the after-tax contribution margin of each of its generating units through the end of its respective service life. In essence, contribution margin is operating (market) revenue less: fuel cost, operating and maintenance (O&M) expense, ongoing capital expenditures, allocated administrative and general (A&G)

expenses, other taxes, decommissioning costs and any required life extension costs.

The future market revenue provided by a given generating unit is determined by multiplying its projected generation times a projected market price in each hour. As PECO explains, all generation (unit dispatch) and market price projections were obtained from three analyses (referred to as the EDS, ICF and PHB studies) performed by outside consultants. The separate analyses provide market value estimates that range from a low of $2.86 billion (PHB) to a high of $3.65 billion (EDS), with the ICF estimate at $3.49 billion.

Q. Which of the above market value estimates does PECO utilize for purposes of determining its stranded costs?

A. PECO adopts the PHB market value estimate of $2.86 billion to develop its stranded cost claim.

Q. Is this the same approach that PECO used in its securitization filing (Docket No. R-00973877)?

A. No. In Docket No. R-00973877, PECO averaged (i.e., gave equal weight to) the three market value estimates of its consultants.

Q. What is the average of the three market value estimates provided by PECO's consultants in this proceeding?

A The average is $3.33 billion, or approximately $470 million higher than the PHB analysis utilized by PECO.

Q. Why has PECO chosen to use the PHB market value figure rather than give equal weight to all three estimates?

A. Mr. Hill provides two reasons for PECO's decision. First, PECO claims PHB's levelized market value estimate of 3.46 cents per kWh appears more in line with many of the market value estimates that were previously presented to the Commission during the restructuring debate.

Second, Mr. Hill claims that "the uncertainty regarding future market prices works to the benefit of customers." In particular, if future market prices should be higher than PECO's estimates, customers can continue to receive service from the Company at generation rates that are, in effect, capped at below-market levels. In contrast, Mr. Hill argues, should market rates turn out to be lower than forecast, customers will be free to take advantage of such lower prices while PECO would be unable to recover the future market revenue (value) attributed to its generating plant.

Q. Does PECO indicate that the PHB analysis is intrinsically superior in any way to either the EDS or ICF analyses,

such as with respect to the unit dispatch model itself or the choice of input values?

A. No, to my knowledge PECO selected the PHB analysis based strictly on its result.

Q. **Mr. Kalcic, is Mr. Hill's first point a valid reason to rely solely on the PHB market value estimate to develop PECO's stranded cost claim?**

A. No. If the Commission had wished to adopt PJM market prices based on the market value estimates that were presented during the restructuring debate that culminated in the passage of the Electricity Generation Customer Choice and Competition Act (Competition Act), it could have done so.

Q. **With respect to Mr. Hill's second argument, do you agree that future market price uncertainty works unambiguously to the benefit of customers and against the interests of utility shareholders?**

A. No, there are other factors that must be considered here. To begin, in the case where actual market prices are higher than forecast, the capped market prices that might provide customers with below-market generation rates would only be in effect during the period of CTC recovery. Any market prices that would exceed PECO's estimates in the relevant period beyond the rate cap

(i.e., over the remaining course of the service lives of its current generating units: from 2006 to 2029) would be achieved by PECO. Also, customers would not necessarily receive full protection from higher than forecast market prices even during the rate cap. Specifically, those customers initially purchasing energy at rates below the price cap could obviously see rates rise up to the capped level (and would, in effect, receive no benefit at all if prices remained below the cap).

Next, consider the case where actual market prices are lower than forecast. First, not all customers will be eligible to take advantage of such lower prices during the first two years of the Phase-In. Second, even when all customers are eligible to participate in Direct Access, it is unclear just how quickly many customers will actually do so. (See, e.g., PECO's response to ENRON-II-1.)

Q. What are your conclusions with respect to the above?

A. On balance, I do not believe it is valid to conclude that the Competition Act "tips the scales decidedly in favor" of customers as opposed to shareholders, as Mr. Hill alleges. Consequently, I recommend that the Commission reject PECO's proposal to rely solely upon the PHB market analysis when determining PECO's stranded costs.

Q. Mr. Kalcic, do you recommend that the Commission simply take the average of PECO's three market value estimates in order to determine the stranded cost associated with the Company's net generating plant and CWIP, as PECO proposed in Docket No. R-00973877?

A. No. The results of the separate market value models presented by PECO provide a range of market value estimates. However, PECO has not adequately assessed the degree of uncertainty associated with the individual market price estimates forming that range. In the absence of such an assessment, the Commission should consider an adjustment to the average of PECO's three market value estimates in order to share the costs associated with the uncertainty of future market price forecasts between customers and shareholders.

Q. What is the source of the uncertainty mentioned above?

A. Each market value estimate is derived from an economic dispatch model which utilizes a number of input assumptions. For example, each dispatch model must incorporate forecasts and/or assumptions regarding such factors as load levels, fuel costs, required reserve margins, transmission constraints and generating unit characteristics. To the extent that actual input values differ from the forecast values employed in the models, the expected market price of electricity would change.

This is a primary source of the market price uncertainty inherent in PECO's models.

Q. Can the uncertainty associated with <u>future</u> market price estimates ever be completely quantified?

A. No. However, it is possible to attempt to form a high and low interval or bound around a given market value estimate by examining the sensitivity of a base case forecast to changes in key input factors. The interval estimate obtained would be one measure of the uncertainty associated with a specific forecast. One could then attempt to judge the reasonableness of a given market value forecast by evaluating where it stood in relation to a range of likely market value outcomes.

Q. Has PECO conducted any "in-house" analysis to test the sensitivity of each market value model to changes in the values of key inputs?

A. Not to my knowledge.

Q. In your opinion, should PECO have presented sensitivity analysis results in support of its market value estimates?

A. Yes. Since the long-range forecasts with respect to such key inputs as fuel prices and load growth can be expected to deviate from actual values, it is important to

investigate the sensitivity of PECO's individual market value estimates to changes in such factors.

Q. What is the forecast period for the fuel prices used in the EDS, ICF and PHB models?

A. The EDS and PHB models use a DRI fuel forecast from 1999 to 2015. ICF utilizes its own fuel price forecast for the same period. From 2015 until 2029, fuel prices are further assumed to escalate at the same rate as the GDP deflator.

Q. How far into the future does the electric load forecast extend?

A. All three models utilize the Mid Atlantic Area Council (MAAC) load forecast extending through 2005. Beyond that time, load is assumed to grow at a constant rate equal to the average of the 2003-2005 period.

Q. What type of sensitivity analysis has the Company conducted at the request of other parties?

A. At the time this testimony was prepared, the only sensitivity analysis conducted by the Company had been that requested by the OCA in Interrogatory OCA-X-12. (The OCA-X-12 analysis used a specific set of fuel and capacity prices in all three market value models in order

to isolate methodological differences within the studies.)

Q. Has the OSBA requested any sensitivity analyses with respect to the EDS, ICF and PHB models?

A. Yes. OSBA-I-26 requested separate sensitivity runs with respect to fuel prices, load growth and capacity reserve margins. However, PECO objected to the request, in part, due to the large amount of resources that would be required to perform the analyses.

As this testimony was being finalized, PECO and the OSBA reached an agreement to proceed with the load growth sensitivity analysis only. Specifically, PECO will rerun the three market value models to quantify the effects of an annual rate of growth in load that is 0.5% above and below the load growth forecast contained in the filed studies. The results of this sensitivity analysis will be discussed in testimony that will be filed later in this proceeding.

Q. Did you request any sensitivity run with respect to load growth in PECO's securitization proceeding?

A. Yes. Interrogatory OSBA-1-7 in Docket No. R-00973877 requested that the Company quantify the effect of a 10% swing in market energy prices, both up and down, on the NPV of the contribution margin of its generating units.

Subsequent discussions with PECO clarified the point that the market price change should be modeled as demand-driven.

PECO provided the above sensitivity analysis with respect to the ICF model sponsored by Dr. Venkateshwara, and the results were presented in Schedule 1 of OSBA Exhibit 1 in the securitization proceeding. As previously reported, a given demand induced price change produced a greater upside than downside impact on market value.

Q. What did you conclude at that time?

A. I concluded that PECO appeared to have a greater potential for upside gain than downside loss in connection with a given market price change. In addition, I indicated that such an asymmetrical impact should warrant an upward adjustment to PECO's base case market value estimate, everything else the same.

Q. Would you recommend an upward adjustment to the base case market value estimate that is ultimately determined in this proceeding?

A. If the sensitivity analyses conducted in this proceeding indicate that PECO would be likely to experience a greater upside than downside in connection with market price uncertainty (or if the record with respect to this

issue remained incomplete due to the lack of such analyses), I would recommend that the Commission implement a market value/stranded cost adjustment so as to implicitly share the risks associated with the uncertainty of future market price estimates between customers and shareholders.

CTC Allocation Methodology & Unbundled Rates

Q. How does PECO propose to allocate its requested CTC revenue requirement among rate classes?

A. The Company proposes to allocate its claimed CTC revenue requirement in proportion to each class' share of the Fixed Production Revenue Requirement (FPRR) obtained from its cost-of-service study conducted for the year ending December 31, 1996 (Exhibit RAC-1).

Q. Does Exhibit RAC-1 reflect the same cost allocation methodologies utilized by PECO in its most recent base rate proceeding (Docket No. R-891364)?

A. Yes. Individual allocation factors have been updated, but it is my understanding that the cost methodologies utilized in Exhibit RAC-1 do not deviate in any significant manner from those employed in Docket No. R-891364.

Q. Why does PECO propose to allocate CTC costs in the above manner?

A. Section 2808(a) of the Competition Act requires that CTC costs "be allocated to customer classes in a manner that does not shift inter-class or intra-class costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the electric utility's most recent base rate proceeding." In an attempt to comply with this directive, PECO has in effect substituted its claimed annual CTC revenue requirement for the fixed production costs currently recovered in each class' present rates, as determined in Exhibit RAC-1.

Q. Is it reasonable to allocate all of the components of PECO's claimed CTC revenue requirement on the FPRR allocator?

A. No. The Deferred Fuel component of PECO's annual CTC revenue requirement claim ($56.8 million per OCA-IV-3) is unrelated to the FPRR (or 4CP) allocator. Instead, page 79 of Exhibit RAC-1 indicates that deferred fuel accounts are a function of class energy use at the meter. Accordingly, I recommend that the above class energy allocator be utilized to assign the Deferred Fuel component of PECO's CTC costs. (All other CTC components would continue to be assigned by the FPRR allocator.)

Q. Is your recommended change to PECO's CTC allocation methodology consistent with the Company's method of allocating the energy-related portion of its Intangible Transition Charge (ITC) request in Docket No. R-00973877?

A. Yes. In its securitization filing, PECO recognized that a small portion of its requested ITC was related to the securitization of deferred fuel costs. Since such costs are energy-related, PECO properly utilized an energy allocator to assign the deferred fuel portion of its ITC to rate classes. My proposal would allocate the Deferred Fuel component of PECO's CTC claim in the same manner.

Q. Does your recommended CTC allocation methodology comply with Section 2808(a) of the Competition Act?

A. Yes. Since Deferred Fuel costs would be allocated using the methodology contained in Exhibit RAC-1, there would be no inherent shifting of costs between rate classes.

Q. What would be the impact of utilizing your recommended allocation methodology to assign the Deferred Fuel component of PECO's CTC claim to rate classes?

A. Schedule 1 of OSBA Exhibit 1 shows the change in each class' CTC allocation that would result from my recommended methodology. Column 1 of Schedule 1 contains PECO's class energy allocator for sales at the meter (C2

in Section IV of Exhibit RAC-1, excluding Rate OP and Interdep). Column 2 shows the OSBA's Deferred Fuel assignment using the allocator in column 1. Column 3 provides PECO's implicit Deferred Fuel allocation, and column 4 shows the difference across the two methodologies.

Q. Mr. Kalcic, do you have any comments regarding the unbundled rates that are shown for Rate GS in Exhibit WFS-3?

A. Yes. PECO's response to OSBA-I-7 indicates that revenues from Rate GS Space Heating customers ($27.1 million) were not properly credited against the total Rate GS revenue requirement when developing unbundled rates. As a result, the unbundled transmission, (variable) distribution and CTC rate components shown for Rate GS in Exhibit WFS-3 are too high, and the Rate GS electric generation (market) charges are too low. (See OSBA-I-8.)

Q. Have you prepared a schedule showing the corrected Rate GS unbundled rate components?

A. No. It is my understanding that PECO will be filing updates and/or corrections to Exhibit RAC-1 which are expected to flow through to Exhibit WFS-3. I expect that PECO will file the corrected unbundled rate components for Rate GS at the time it updates Exhibit WFS-3.

Phase-In Procedures & Customer Eligibility

Q. Mr. Kalcic, how does PECO propose to implement the Phase-In of all customers to Direct Access?

A. In compliance with the Competition Act, PECO proposes to phase-in Direct Access in three steps. As of January 1, 1999 a maximum of one-third of the peak load of each customer class would be eligible for Direct Access. Each succeeding January, PECO would offer customers comprising an additional one-third of the load of each customer class the opportunity for Direct Access, so that by January 1, 2001 all customers would be eligible.

Q. Please summarize PECO's proposed method for determining which customers within the commercial and industrial customer classes will be eligible to participate in steps one and two of the Phase-In.

A. Briefly, the Competition Act directs all electric companies to select commercial and industrial customers for Direct Access on a "first-come-first-served" (FCFS) basis. However, the Commission may allow other approaches in order "to prevent competitive disadvantages among similarly situated customers within a customer class."

Under PECO's proposed selection procedure, all customers will receive an information packet regarding

Direct Access by July 1, 1998. Included in this information packet will be a registration card which commercial and industrial customers must return in order to be eligible for the Phase-In. PECO will select customers for Direct Access according to the order that registration cards are received (processed). Commercial and industrial customers must mail the registration card to PECO postmarked on or after October 1, 1998 (i.e., no pre-registration or other forms of registration would be allowed). Furthermore, to maintain impartiality, PECO would employ centralized processing for all registration cards so that individual accounts would have an equal chance to participate in the Phase-In.

After processing a registration card, PECO would inform the customer of his/her eligibility or ineligibility in the Phase-In depending on whether his/her customer class was, respectively, under- or over-subscribed. In the latter case, the customer would be notified of the enrollment date for the second step of the Phase-In.

Q. Which rate class(es) has PECO designated as the commercial customer class?

A. PECO has designated Rate GS (General Service) to be the commercial customer class (per OSBA-I-15).

Q. Please describe the general composition of customers on Rate GS.

A. Rate GS is available to all offices, commercial or industrial establishments, governmental agencies, and other non-residential applications that take electric service through a single metering installation at secondary voltage.

Q. Is Rate GS homogeneous with respect to customer size?

A. No. As might be expected when all non-residential secondary customers (other than lighting) are served on a single tariff, accounts on Rate GS exhibit a wide range of billing demand sizes -- from the tariff minimum of 1.2 kW to well over 100 kW. Schedule 2 of OSBA Exhibit No. 1 provides a summary of the distribution of total Rate GS customers, by billing demand interval. Of 142,421 Rate GS accounts in August 1996, over 50,600 exhibited a billing demand of 3 kW or less. The number of accounts with billing demands of 25 kW or less was approximately 124,000 or 87% of the total class.

At the other end of the spectrum, just 3,288 accounts (2.3%) show a billing demand greater than 100 kW. Yet, these relatively few large customers represent a very substantial percentage of the total Rate GS peak load. Interrogatory OSBA-I-16 asked PECO to calculate how many of these largest customers it would take to

fully subscribe the total Rate GS peak demand (571 MW) that would be available in the first step of the Phase-In. According to that response, beginning with the largest customer, only 1,900 Rate GS customers, averaging approximately 300 kW in size, would be necessary to fully subscribe the commercial class in Phase I. These customers represent just 1.3% of all Rate GS accounts.

Q. **What implication does the wide range of customer sizes within Rate GS have regarding the ultimate distribution of commercial customers chosen for the first two steps of the Phase-In?**

A. In my opinion, the wide range of customer sizes exhibited among Rate GS accounts is likely to result in an under-representation of smaller Rate GS customers in the first two steps of the Phase-In.

Q. **Please explain.**

A. The larger a customer's electric bill, the greater the potential for savings associated with Direct Access. As a result, I would expect larger customers to have a naturally greater incentive to process and evaluate Direct Access information, and to do so in a more timely fashion than smaller customers. All else equal, therefore, larger customers may be expected to respond more promptly to PECO's Phase-In registration program,

resulting in large accounts being over-represented among Rate GS customers accepted in the first two steps of the Phase-In.

Q. Should PECO's proposed Phase-In selection methodology for commercial customers be modified to counter-balance the potential selection "bias" discussed above?

A. Yes.

Q. What is your recommendation in this area?

A. I recommend that the PECO's Direct Access selection process within Rate GS be modified to allow for a proportionate representation of smaller Rate GS customers in the first two steps of the Phase-In. To that end, the total Rate GS peak load available in the first two steps of the Phase-In should be reapportioned into separate "Small Rate GS" and "Large Rate GS" segments. The eligibility of commercial customers who return their registration cards would then be determined on a FCFS basis within the appropriate Rate GS load segment.

Q. At what load level should Rate GS be segmented for Phase-In purposes?

A. Given the distribution of accounts across the load intervals shown in Schedule 2, I recommend that the Small Rate GS segment be limited to customers with no more than

40 kW loads. (Rate GS accounts greater than 40 kW number less than 8% of the total, and the customers reported in the 40 kW to 100 kW demand interval may be much larger than 40 kW.) However, the natural breakpoint may be more precisely determined from a more detailed bill frequency analysis than contained in OSBA-I-14.

Q. How much Rate GS load would PECO need to designate as Small Rate GS in each of the first two steps of the Phase-In?

A. Based on load research, PECO would designate one-third of the peak load of the defined Small Rate GS segment in the first step of the Phase-In, and two-thirds of the respective load for step two. The same would apply for the Large Rate GS segment, with the total of the segmented load levels eligible for a given year of the Phase-In equal to that allowed for Rate GS as a whole.

Q. Mr. Kalcic, is the overall intent of your proposal any different than what might be expected in the case where PECO's tariffs included separate small and large general service rate classes?

A. No. In that situation, I would expect that PECO would determine Phase-In eligibility on a FCFS basis <u>within the individual rate classes</u> that comprised the commercial customer class. Indeed, this is my understanding of how

PECO intends to determine eligibility within its industrial customer class which contains both Rate PD and Rate HT customers.

In the case where PECO's tariff contained separate general service classes, the composition of the individual rate classes would be much more homogeneous, and the need for further segmentation significantly reduced. In that respect, the intent of the OSBA's proposal is simply to provide small business customers with the same opportunity for Direct Access in the first two steps of the Phase-In that would be forthcoming from a more traditionally differentiated general service class.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX

APPENDIX

Qualifications of Brian Kalcic

Mr. Kalcic was graduated from Illinois Benedictine College with the degree of Bachelor of Arts in Economics in December, 1974. In May, 1977 he was awarded a Master of Arts degree in Economics from Washington University, St. Louis. In addition, he has completed all course requirements at Washington University for a Ph.D. in Economics.

From 1977 to 1982, Mr. Kalcic taught courses in economics at both Washington University and Webster University. The courses that he taught included Microeconomic and Macroeconomic Theory, Labor Economics and Public Finance.

During 1980 and 1981, Mr. Kalcic was a consultant to the Equal Employment Opportunity Commission, St. Louis District Office. His responsibilities included data collection and organization, statistical analysis and trial testimony.

From 1982 to 1996, Mr. Kalcic was employed by the firm of Cook, Eisdorfer & Associates, Inc.. During that time, he participated in the analysis of electric, gas and water utility rate case filings. His primary responsibilities included cost-of-service and economic analysis, model building, and statistical analysis.

In March 1996, Mr. Kalcic founded Excel Consulting, a consulting practice which provides business and regulatory analysis.

Mr. Kalcic has previously testified before the state regulatory commissions of Kentucky, Maine, Massachusetts, Minnesota, Missouri, New Jersey, New York, Ohio, Oregon, Pennsylvania, Texas, and the Bonneville Power Administration.

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EXHIBIT OF

BRIAN KALCIC

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

PECO ENERGY COMPANY
Comparison of OSBA and PECO Allocation
of the Deferred Fuel Component of CTC Costs
($1,000)

Line	Rate Class	kWh at Meter (%)	OSBA Deferred Fuel Allocation	Company Deferred Fuel Allocation	Difference
		(1)	(2)	(3)	(4)
1	HT	41.055%	$23,328	$19,796	$3,533
2	EP	1.982%	$1,126	$867	$260
3	PD	3.357%	$1,907	$1,909	($2)
4	GS	20.471%	$11,632	$14,677	($3,045)
5	RH	8.740%	$4,966	$4,075	$891
6	R	23.893%	$13,576	$15,416	($1,839)
7	OP	0.000%	$0	$0	$0
8	SLP	0.276%	$157	$39	$117
9	SLS	0.052%	$30	$24	$6
10	SLE	0.146%	$83	$18	$65
11	OTHER	0.028%	$16	$2	$14
12	TOTAL	100.000%	$56,822	$56,822	$0
	Source:		Tot x C1	Tot Allocated on Fixed Prod Allocator	C2 - C3

Notes: KWh at meter (%) excludes Rate OP and Interdep.
Total Deferred Fuel CTC cost of $56.8 million per year provided in OCA-IV-3.

PECO ENERGY COMPANY
Estimated Distribution of Rate GS Customers
by Average Billing Demand

Line	Avg. Demand	Number of Rate GS Customers - August 1996			
		With Demand Measurement	W/O Demand Measurement	Total	% of Total
		(1)	(2)	(3)	(4)
1	1.2 - 3.0 kw	14,987	35,628	50,615	35.5%
2	3.1 - 7.0 kw	14,137	7,520	21,657	15.2%
3	7.1 - 10.0 kw	21,183		21,183	14.9%
4	10.1 - 15.0 kw	16,578		16,578	11.6%
5	15.1 - 25.0 kw	13,931		13,931	9.8%
6	25.1 - 40.0 kw	7,668		7,668	5.4%
7	40.1 - 100.0 kw	7,511		7,511	5.3%
8	over 100 kw	3,288		3,288	2.3%
9	Total	99,283	43,148	142,431	100.0%

Source: OSBA-I-14
Note: Avg. demand of customers w/o demand measurement estimated at rate of 175 kWh per kw with 1.2 kw minimum, per Rate GS tariff.

OSBA STATEMENT NO. 1R

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Rebuttal Testimony of

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Date Served: July 18, 1997

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Rebuttal Testimony of Brian Kalcic

Q. Please state your name and business address.

A. Brian Kalcic, 225 S. Meramec Avenue, St. Louis, Missouri 63105.

Q. Have you previously submitted testimony in this proceeding?

A. Yes.

Q. What is the subject of your rebuttal testimony?

A. My rebuttal testimony addresses issues raised by various witnesses in the following three areas: 1) rate unbundling as it pertains to the determination of the CTC versus the market generation component of rates, 2) the allocation of Universal Service costs among rate classes and 3) the functionalization of Administrative and General (A&G) expense and general plant.

CTC & Unbundling Issues

Q. Mr. Kalcic, numerous witnesses in this proceeding, including Mr. Baron for PAIEUG, Ms. Smith for the OCA, Mr. Phillips for the Navy, Mr. Johnstone for the Mid-Atlantic Power Supply Association (MAPSA) and Mr. Boonin for New Energy Venture (NEV), have criticized PECO's proposed methodology for determining the CTC versus the

market generation component of unbundled rates. Specifically, each witness is critical of PECO's approach of first allocating CTC costs and then determining the unbundled market generation component of rates as a residual. What is the main argument underlying this criticism?

A. Although not all witnesses discussed the subject in the same depth, I believe each witness noted that PECO's methodology would establish little, if any, opportunity for customer choice during the CTC recovery period due to the fact that the residual market value components of PECO's unbundled rates were almost universally below the Company's own estimates of future market prices.

Q. Do you agree that the above observation is a valid criticism?

A. Certainly. In order for Direct Access to provide benefits, customers must have meaningful choices. I also agree that meaningful choice is particularly important during the period of transition to a competitive market. However, as discussed below, I believe the criticism directed toward PECO's approach to unbundling is more accurately characterized as pertaining to the level of the Company's overall stranded cost claim rather than its unbundling methodology, per se.

Q. Why do you state that the above criticism more aptly applies to PECO's stranded cost claim rather than its unbundling methodology?

A. To contrast the market generation rates produced under PECO's methodology (CTC-first, market generation-residual) with those obtained by the opposite approach (market generation-first, CTC-residual) is, in reality, an apples and oranges comparison at PECO's claimed stranded cost level. This follows from the fact that the two approaches would provide vastly different amounts of stranded cost recovery.

It is valid to say that PECO's full stranded cost claim cannot be recovered over a seven year period under the existing rate cap while still providing meaningful customer choice (based on the market price projections submitted in this proceeding). It is equally valid to state that the CTC-residual approach cannot provide meaningful customer choice while simultaneously recovering PECO's full stranded cost claim over a seven year period. While ratepayers are certainly better off in the case where the present value of CTC payments are lower, this observation, in and of itself, does not imply that the CTC-residual approach is superior. To properly compare the two unbundling methodologies, one must consider the case where it is possible to recover a given amount of stranded costs under either unbundling

approach. Under these conditions, I believe it is appropriate to allocate the CTC revenue requirement to rate classes as part of the unbundling process.

Q. Do any of the above witnesses (i.e., those who advocate that the market generation component of unbundled rates be based on market price projections) combine an allocation of the CTC revenue requirement with a market-price-based generation component in their recommended unbundling of rates?

A. Yes. OCA Witness Lee Smith utilizes such an approach. As both the CTC charge and market generation component of rates are exogenously determined in Ms. Smith's analysis, the remaining space in a given year under the existing rate cap becomes a residual rate reduction.

Q. How does Ms. Smith's unbundling methodology compare to that offered by PAIEUG Witness Stephen J. Baron?

A. In Mr. Baron's analysis, there would be no residual rate reduction. Instead, all classes would pay CTC charges equal to the full difference between their existing generation rate cap (i.e., current rates less the unbundled transmission and distribution components) and the market generation component of rates. In essence, classes with more "space" under the existing generation rate cap would pay CTC charges for those classes that had

less space, until PECO recovered its total stranded costs. (In Mr. Baron's analysis, PECO is projected to recover PAIEUG's recommended stranded cost revenue requirement by May 2001.)

Q. Under Mr. Baron's unbundling approach, would certain rate classes end up paying more than their equivalent (PECO) allocated share of total CTC costs?

A. Yes. Depending on the size of a class' embedded generation rate cap in Mr. Baron's analysis, some classes will pay more, others less, than their PECO allocated share.

In the case of Rate GS, the class' allocated share of PAIEUG's recommended stranded cost revenue requirement is given by the product of PECO's Rate GS CTC allocator (0.25829) times $2.21 billion or $570.7 million. In Baron Exhibit ___ (SJB-5), Rate GS customers are amortizing the equivalent of $608.6 million of the $2.21 billion total. Mr. Baron's unbundling methodology therefore assigns an additional $37.9 million of CTC cost responsibility to Rate GS customers simply because the class' current rates provide the additional space under the generation rate cap.

Q. Is it appropriate for certain rate classes to provide a total amount of stranded cost recovery in excess of their allocated responsibility (on a present value basis)?

A. No. The available space a class exhibits under the generation rate cap (i.e., after transmission and distribution services are unbundled) is a function of its current rates. Within a given generation rate cap, one would expect those classes which implicitly pay larger "premiums" for generation under existing bundled rates (i.e., pay a larger amount over their respective market rates) to receive greater benefits from Direct Access. This follows from the premise that competition will eliminate all generation premiums paid by ratepayers.

During the period of transition to competition, Mr. Baron proposes to utilize all available generation premiums to amortize PECO's total stranded costs as quickly as possible. In doing so, Mr. Baron would shift CTC cost responsibility from low premium to high premium classes, effectively denying the latter their proportionate share of benefits during the period of stranded cost recovery.

Q. Is Mr. Baron's unbundling approach necessary to provide customer choice at PAIEUG's recommended stranded cost level?

A. No. The OCA's annual, levelized CTC revenue requirement recommendation ($536.4 million) exceeds that of PAIEUG ($486.5 million). In the case where CTC costs would be recovered on a levelized basis, the OCA found it feasible to allocate its recommended CTC revenue requirement to rate classes while at the same time providing for market-based generation rates (i.e., meaningful customer choice). Therefore, it should be possible to do the same with PAIEUG's levelized stranded cost revenue requirement.

Q. Mr. Kalcic, PAIEUG has recommended that the CTC revenue requirement not be collected on an annual, levelized basis, but instead be amortized over the seven (or fewer) year transition period. Would it still be feasible to allocate CTC costs to rate classes in the case where total stranded costs are amortized?

A. Yes. Under that scenario, each class would be allocated its share of the beginning stranded cost balance with CTC revenue collections tracked by class. Each class would pay residual CTC charges up to the level of its respective generation rate cap, as in Mr. Baron's recommended rate design, but since the CTC charges paid by class would be credited against a class-specific stranded cost allocation, the CTC charges for a given class would end when its allocated share was amortized.

This condition would maintain equity among rate classes during the period of stranded cost recovery.

Combining PAIEUG's recommended approach of amortizing PECO's total stranded costs with an allocation of CTC revenue responsibility would therefore result in the CTC ending at different times for each rate class.

Q. Are you recommending that PECO's total stranded costs be amortized rather than collected on an annual, levelized basis?

A. No. My point is simply that whichever recovery approach the Commission decides to adopt, it would be appropriate to allocate the CTC revenue requirement to rate classes in the unbundling process.

Universal Service Funding

Q. PECO has proposed that Universal Service Fund costs be collected from residential customers only. Many witnesses in this proceeding, including Ms. Brockway for the OCA, Mr. Metro for the OTS, Dr. Cooper for the AARP and Mr. Colton for the Environmentalists, have recommended instead that such costs be collected from all classes of ratepayers. Do you believe it would be appropriate to collect Universal Service Fund costs from all rate classes?

A. No. As indicated by the Company, all Universal Service costs are associated with residential customers. In addition, the direct benefits of Universal Service accrue to residential customers. Given these circumstances, I believe it is appropriate that Universal Service Fund costs be collected solely from the residential rate classes.

Q. Does the Competition Act require that Universal Service Fund costs be recovered from specific rate classes?

A. No. The Competition Act does not specify which class(es) should provide funding for Universal Service. The Competition Act states only that Universal Service be "...funded in each electric distribution territory by nonbypassable, competitively-neutral cost recovery mechanisms that fully recover the costs of Universal Service and energy conservation services." (§ 2804(9)).

However, in PECO's case, I believe Section 2804(4) of the Competition Act effectively precludes any non-residential classes from funding Universal Service costs at this time.

Q. Please explain.

A. Section 2804(4) of the Competition Act establishes a rate cap of up to 54 months (until June 30, 2001) on nongeneration-related charges in effect as of the

effective date of the legislation. If the Company's proposed Universal Service Fund budget of $35.7 million were to be collected from all ratepayers on a kWh basis, as proposed by many of the previously identified witnesses, approximately $24.2 million would be shifted to non-residential classes (per PECO's (C2) energy allocator shown on page 44 of Exhibit RAC-1).

Consider, however, that in PECO's last base rate case, all CAP-related costs were collected from the residential rate classes. Consequently, the unbundled nongeneration-related charges identified for non-residential customers in this proceeding do not currently include Universal Service costs. To now shift $24.2 million of costs that were previously collected from residential customers to non-residential customers would necessitate an increase in the latter's current nongeneration-related charges, in violation of the rate cap provisions of the Competition Act.

A&G Functionalization

Q. In Exhibit RAC-1, PECO has chosen to functionalize certain A&G expenses and General/Common plant costs as solely transmission- and/or distribution-related. Various witnesses in this proceeding, including Mr. Baron for PAIEUG, Ms. Smith for the OCA, Mr. Reising for Enron,

Mr. Phillips for the Navy and Mr. Johnstone for the Mid-Atlantic Power Supply Association, have argued that such costs should be classified across all functional areas, including production. Do you agree that A&G expenses and General/Common plant costs exhibit a production-related component?

A. Yes. Traditional cost-of-service methodologies, including those employed by PECO in its last base rate case, recognize that a portion of the above cost categories are production-related. Absent a valid demonstration by PECO that all embedded A&G expenses would become nongeneration-related upon the offering of Direct Access, such costs should be assigned to all three functional categories.

I concur with the above witnesses that, to date, PECO has not provided a valid argument to support its proposed functionalization of A&G expenses and General/Common plant costs, and consequently its unbundled distribution charges which are based on Exhibit RAC-1 are too high.

Q. Does this conclude your rebuttal testimony?

A. Yes.