R-00973953, R-00973953C0001 - C0003 et al
PECO STATEMENT NO. 1-ER
Phila 11/18/97
E. A.

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

REBUTTAL TESTIMONY

OF

THOMAS P. HILL, JR.
REGARDING THE ENRON PLAN

Regarding Testimony Submitted By The
Environmentalists And New Energy Ventures

November 12, 1997

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF THOMAS P. HILL, JR.
REGARDING THE ENRON PLAN

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. Thomas P. Hill, Jr., 2301 Market Street, Philadelphia, PA 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Vice President and Controller.

Q. **Have you previously participated in this proceeding?**

A. Yes. I submitted direct testimony (PECO St. 1) and various supporting exhibits (Exhibits TPH-1 through TPH-14) with PECO's April 1, 1997 restructuring filing. A statement of my qualifications is contained in my direct testimony. I later submitted supplemental direct testimony (PECO St. 1-S) and an accompanying exhibit (TPH-15) in which I responded to certain questions posed by Commissioner Hanger. On July 18, 1997, I submitted rebuttal testimony (PECO St. 1-R) and accompanying exhibits (Exhibits TPH-16 through TPH-25) in which I updated PECO's stranded cost claim and responded to various proposals advanced by other parties to this proceeding. On September 17, 1997, I submitted supplemental rebuttal testimony (PECO St. 1-SR) and accompanying exhibits (Exhibits TPH-26 through TPH-28) in which I explained why, in PECO's view, approval of the August 27, 1997 Joint Petition For Partial Settlement Of PECO Energy

Company's Proposed Restructuring Plan And Application For A Qualified Rate Order (the "Partial Settlement ") is in the public interest. On October 8 and 13, 1997, respectively, I submitted rejoinder and supplemental rejoinder testimony (PECO Sts. 1-RJ and 1-SRJ) and accompanying exhibits (Exhibits TPH-29 through TPH-32) in which I responded to various objections to the Partial Settlement. Finally, on November 7, 1997, I submitted testimony (PECO St. 1-E) and accompanying exhibits (Exhibits TPH-33 through TPH-36) in which I explained why the so-called "Choice Plan" submitted by Enron Energy Services Power, Inc. ("Enron") on October 7, 1997 (the "Enron Plan") was not in the public interest and should be rejected.

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

A. This testimony responds to testimony submitted on November 7, 1997 by witnesses for the Environmentalists and New Energy Ventures ("NEV"). I will first explain why the Commission's consideration of that testimony would be inappropriate and unfair. I will then address certain aspects of the Environmentalists' "Better Choice Plan" and will comment briefly on NEV witness Boonin's "alternative" proposals.

II. THE OPPOSING PARTIES' TESTIMONY IS UNTIMELY

Q. **What is your understanding of the purpose of this phase of the proceeding?**

A. This phase of the proceeding was designed to provide the parties an opportunity to address the Enron Plan. As set forth in Prehearing Order #5, which was issued by the presiding Administrative Law Judges on October 17, 1997, testimony in support of the

Enron Plan was to have been filed on or before October 24, 1997; testimony in opposition to it was due on November 7, 1997. Much of the testimony submitted by the Environmentalists and NEV is, to a large measure, inappropriate and, for the reasons set forth in the Motion that PECO is filing concurrently herewith, should be stricken.

Q. **Why, in your view, is the Environmentalists' testimony inappropriate?**

A. Because the Environmentalists seek to utilize this additional round of testimony to launch an entirely new proposal at the eleventh hour. Most of the Environmentalists' testimony, particularly that submitted by Messrs. Biewald and Schoengold, has nothing to do with the Enron Plan, but rather is a vehicle by which the Environmentalists present their latest "wish list". As a stand-alone proposal, the Environmentalists' "Better Choice Plan" should have been submitted in June when the opposing parties filed responsive testimony to PECO's restructuring proposal. Alternatively, the Environmentalists could have submitted the "Better Choice Plan" at a separate docket, with full notice provided to customers, and asked that it be consolidated with this case. Instead, the Environmentalists, through the guise of testimony "opposing the Enron Plan", would dump into this proceeding a host of issues which were not raised previously and, as to which, other parties and the public have been given insufficient notice and opportunity to respond.

Q. **Why do you object to consideration of the NEV testimony?**

A. Like the Environmentalists' testimony, much of the NEV testimony is not responsive to the Enron Plan. Rather, Mr. Boonin critiques various elements of the Partial Settlement (e.g., amount of stranded cost recovery allowed, discount rate and sales level assumptions) and offers support for the position previously submitted by the Pennsylvania Electric Competition Coalition ("PECC"), of which NEV is a member. As such, Mr. Boonin's testimony, in order to be considered, should have been filed at the end of September and cross-examined during the hearings held in mid-October. It is clearly untimely and should similarly be stricken.

III. THE OPPOSING PARTIES' SUBSTANTIVE PROPOSALS ARE WITHOUT MERIT

Q. **What's wrong with the "Better Choice Plan" from a substantive standpoint?**

A. The "Better Choice Plan" is deficient in a number of respects: (1) it is anti-competitive; (2) it is grossly unfair to PECO; and (3) it is not achievable statutorily. Indeed, the principal beneficiaries of the "Better Choice Plan" would not be Pennsylvania consumers, but rather the Environmentalists who would leverage electric utility restructuring into a new and large source of funding to promote their own agenda.

Q. **Why is the "Better Choice Plan" anti-competitive?**

A. The "Better Choice Plan" is anti-competitive because competitors' market shares would be determined not on the basis of the free choices of consumers, but rather on an artificial pre-determined Commission-mandated allocation scheme. More specifically, under the Environmentalists' proposal, if less than 50% of PECO's customers selected an alternative electric generation supplier ("EGS"), all default customers would be assigned to non-incumbent EGSs in proportion to the market share each such EGS initially achieved in the customer selection process. In other words, customers would have to take affirmative action in order to continue to be served by PECO or risk being assigned to a supplier not of their choice or volition. This strikes me as tantamount to "slamming", which has been severely condemned by the public and the Commission in the telecommunications area, and is likewise a concern as electricity markets become competitive. In fact, the Competition Act (§2807(D)(1)) requires that the Commission promulgate regulations to ensure that customers do not have their supplier switched without their consent and the Commission's proposed rules, published October 11, 1997 in the Pennsylvania Bulletin, require verbal and written authorization from customers to switch suppliers.

Q. **Is the Environmentalists' proposal anti-competitive in any other respects?**

A. Yes. The "Better Choice Plan" would further skew the operation of competitive markets by requiring participants in the default customer allocation process to (1) subsidize renewable energy sources through the mandatory contribution of 0.5% of their total Pennsylvania electric revenues to the "Pennsylvania Sustainable Development Fund" and (2) offer a resource mix which includes at least 1.0% of renewable resources. These conditions would not promote competition, but instead would provide an artificial prop to a protected class of potential suppliers who might not otherwise be able to compete on their own merit. If customers wish to support renewable energy, they will do so by exercising their right to choose amongst various generation suppliers -- there is no need to interpose a regulatory stimulus to create a market for those services.

Q. **Have you quantified the extent of the subsidy that renewable energy sources would receive if the Environmentalists' 0.5% funding proposal were adopted?**

A. Yes. I estimate that this proposal, if implemented on a state-wide basis, would generate approximately $220 million of "contributions" over the next ten years.

Q. **You mentioned previously that the "Better Choice Plan" was also unfair to PECO. Please explain.**

A. As I indicated earlier, all default customers would be allocated to "non-incumbent" EGSs. In other words, neither PECO nor any affiliated-EGS could participate in the process. Thus, in Mr. Biewald's Example No. 3, PECO would have a 65% market share prior to allocation and a 5% market share after the default customers had been divvied up. At the same time, however, the Environmentalists would impose on PECO "provider of last resort" responsibilities for **all** customers. The resulting imbalance in opportunities and obligations is so fundamentally unfair that the Environmentalists' proposal must be rejected for this reason alone.

Q. **Why is the "Better Choice Plan" unworkable statutorily?**

A. It is unworkable because, in my opinion, the Commission is not empowered to condition competitive entry upon the agreement of the competitor to pay an excise tax in the form of a contribution to a renewable energy fund and/or to maintain a certain generation resource mix. In addition, the Environmentalists' plan would, in effect, put the Commission in business as an environmental watch-dog, ensuring that out-of-state EGSs continuously met "an environmental baseline comparable to the applicable Pennsylvania environmental regulations" (Environmentalists St. 2-E, p. 20). Although PECO certainly favors an environmentally-level playing field, the interplay between electric restructuring and environmental compliance extends far beyond the scope of this proceeding. Moreover, even if the Commission possessed the requisite regulatory authority and necessary resources, it is far from clear how the Commission could monitor compliance with Mr. Biewald's undefined "environmental baseline".

Q. **Do you have any other comments regarding the Environmentalists' testimony?**

A. Yes. In his testimony, Mr. Biewald discusses the Hirfindahl-Hirschmann Index (HHI), which is used in evaluating market concentration, and implies that PECO might possess "market dominance" if it retained as much as 50% of its existing retail load. However, a relatively high HHI is in no way dispositive of market power. To the contrary, I am advised that any number of other factors, including ease of entry, would have to be carefully evaluated. In addition, Mr. Biewald's observations are quite misleading as he assumes that PECO's service territory is the relevant geographic market. In fact, and as all of the market price witnesses in this proceeding properly recognize, the market in which PECO and other suppliers will compete will encompass all of Pennsylvania and other adjoining areas as well. Mr. Biewald's analysis therefore is largely meaningless.

Q. **Did NEV also submit an entirely new proposal?**

A. No. In contrast to the Environmentalists, Mr. Boonin's principal objective appears to be in mustering further support for the position articulated earlier by other PECC witnesses. As such, his testimony is similarly untimely, albeit for different reasons.

Q. **Does Mr. Boonin's testimony bring to light any new facts or arguments?**

A. Not really. Indeed, even when Mr. Boonin purports to critique the weaknesses of the Enron Plan, he simply takes shots at the Partial Settlement (which he inappropriately characterizes as "PECO's Proposal"). In doing so, Mr. Boonin either rehashes old arguments or freely opines on matters for which he offers no independent support.

Q. **Please provide some examples of statements which are unsupported.**

A. Certainly. On page 9 of his testimony, Mr. Boonin asserts that "[n]umbers around 3.75 cents per kilowatt hour seem to better reflect current market conditions than the 3.48 proposed by Enron". Mr. Boonin offers absolutely no market price evidence to support this statement. Moreover, and as noted by Mr. Freeman in the testimony he has submitted in this proceeding, Mr. Boonin's observations regarding "current market conditions" are contradicted by the deals which suppliers are presently offering customers.

Mr. Boonin later takes issue with PECO's implicit discount rate because it allegedly incorporates an excessive equity component. However, Mr. Boonin's only support for his proposed 10.0% equity cost rate is a Commission finding earlier this year in PECO's securitization proceeding, which **all** rate of return witnesses in this case agree seriously understates PECO's current capital costs.

Q. **Please comment on Mr. Boonin's net present value analyses.**

A. Mr. Boonin's analyses suffer for all the same reasons which I identified in discussing Enron witness Oliver's flawed attempts to quantify the relative savings of the Partial Settlement and the Enron Plan (e.g., no recognition of the transactional costs of securitization or the benefits to customers of industrial rate discounts, early rate relief, extension of the rate caps etc.) (<u>see</u> PECO St. 1-E, pp. 16-20). In addition, Mr. Boonin erroneously reflects the impact of securitization in his discount rate without taking into account the effect which securitization would have on PECO's overall mix of capital (more leverage) and cost of money (higher). The appropriate place to reflect the impact of securitization is in the calculation of revenue requirements, as PECO has done (see Exhibit TPH-35), not in the discount rate.

Q. **Are there any other problems with Mr. Boonin's analyses?**

A. Yes. On page 15 of his testimony, Mr. Boonin recognizes that every dollar of revenue received by PECO will be subject to gross receipts tax (GRT). He then contends that PECO erred in calculating its GRT liability by multiplying the revenues received by .956 rather than dividing that amount by 1.044.

Q. **Is Mr. Boonin correct?**

A. No, as a simple example will illustrate. In order to net $100 of revenue after gross receipts tax, PECO must receive $104.60 in electric revenue. As shown in the table below, $104.60 in revenue yields $100 after paying the GRT. The table also shows that the same result is achieved by calculating the GRT specifically or, alternatively, by multiplying the revenue by 0.956 (i.e. the standard method followed by PECO). Under

Mr. Boonin's approach, however, the calculated net revenue is $100.19, leaving $4.41 for GRT, less than the required $4.60. Mr. Boonin's method therefore understates tax liability and overstates revenue.

Standard (i.e. PECO) Method

Revenue	$104.60	$104.60
GRT (4.4%)	4.60	x 0.956
New Revenue	$100.00	$100.00

Boonin Method

Revenue (before GRT)	$104.60
Revenue (net of GRT)	$100.19 ($104.60/1.044)
Estimated GRT	$ 4.41
Required GRT	$ 4.60

Q. **Does that conclude your testimony?**

A. Yes, it does.

R-00973953, R00973953C0001-C0007, et al

PECO STATEMENT NO. 6-E

Phila. 11/17/97

E.H.

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

TESTIMONY

OF

WILLIAM H. HIERONYMUS

REGARDING THE ENRON PROPOSAL

Regarding Energy & Capacity Caps
and Competition

November 7, 1997

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

Q. Please state your name and business address.

A. My name is William H. Hieronymus. My business address is Putnam, Hayes & Bartlett, Inc., One Memorial Drive, Cambridge, MA 02142.

Q. Have you submitted testimony previously in this proceeding?

A. Yes. I submitted PECO Statement No. 6 and accompanying Exhibits No. WHH-1 through WHH-5, PECO Statement No. 6-R and accompanying Exhibits No. WHH-6 through WHH-8, and PECO Statement No. 6-RJ and accompanying Exhibit No. WHH-9.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I am responding to assertions made by Enron witnesses Douglas Bohi and Kenneth Slater regarding the Partial Settlement. The primary focus of my testimony addresses the alleged superiority of the Energy and Capacity Cap proposed by Enron relative to that contained in the Partial Settlement.

Q. Please summarize the portions of Enron's testimony that you are addressing.

A. Dr. Bohi suggests that the Energy and Capacity Caps contained in the Partial Settlement will create a barrier to retail competition that will effectively leave PECO as a monopoly supplier (Enron Statement No. 3, p. 5). He bases his conclusion on the premise that the Energy and Capacity Cap is below the competitive market price of electricity, which he assumes is equal to the long-run marginal cost derived by Mr. Slater. Dr. Bohi goes on to argue that this will frustrate what is his view of the Competition Act's intent to establish a competitive generation market. Finally, Dr. Bohi opines concerning PECO's and Enron's relative ability and incentive to frustrate competition if they are the Provider of Last Resort (PLR).

Q. Please summarize the main conclusion of your testimony.

A. These witnesses have confused the entry of new generation into PJM and Pennsylvania with competition in generation and have further confused competition in generation with competition in providing retail services. This probably accounts for the fact that they have erroneously used the long-run marginal cost of generation based on the cost of a new combined cycle unit as the benchmark for gauging the adequacy of the Energy and Capacity Cap. As a result, they have substantially overstated the market price in a competitive generation market in the near term and hence the bulk power costs that would have to be paid by a retail competitor. Conversely, they have understated the market price of generation in the longer term.

Enron's proposed Energy and Capacity Cap will, unquestionably, provide Enron Power Marketing, Inc. (EPMI) and other entrants with an easy target to beat in attracting customers away from the PLR during the first few years. For reasons I will discuss below, this may translate into supra-competitive profits for successful entrants, which EPMI would be uniquely well-positioned to become, particularly if another Enron subsidiary is the PLR. However, it also is likely that the Cap will come to be below the market price of generation during the later years of the period covered by the cap. In short, adopting the

Enron Cap proposal is very likely to result in squeezing out competition a few short years after it is established.

Q. Why is Enron's estimate of market price excessive in the near term?

A. Enron's estimate, sponsored by Mr. Slater and relied upon by Dr. Bohi, is based on the long-run marginal cost of generation. That is, it is calculated as the total cost, including a return on capital, of an efficient new generating unit. I agree that, in the long run, prices will approximate long-run marginal costs. However, Enron's witnesses mistakenly assume that prices will have to be high enough to cover the cost of an entrant by 1999. The theory that price must approximate long-run marginal cost is based on the simple notion that new capacity will not be built unless it is economic to do so. Hence, once new capacity is needed, prices in a competitive market will have to rise to a level high enough that new suppliers will reasonably anticipate market revenues that are high enough to justify building the needed capacity.

However, this logic also means that when new capacity is not needed, market prices need not be high enough to justify building new capacity. Indeed, if they were, unneeded new capacity would be built, causing competition in energy and capacity markets to drive down prices. As I testified previously, PJM currently has excess capacity. This is reflected in actual transaction prices, as is discussed in Mr. Freeman's testimony, that are well below the long-run marginal costs sponsored by Mr. Slater. This is also reflected in the historic energy prices, as shown in Mr. Bustard's Exhibit JFB-18, taken in concert with the low historic prices for capacity in PJM.

In my analyses, I have projected that prices in PJM will rise to long-run marginal cost by 2001, the first year in which PJM is projected to need new capacity. This same assumption was made by the other market price witnesses, including witnesses for PAIEUG and OCA. In years prior to 2001, projected prices ramp up from current levels to long-run marginal cost and thus are appropriately below long-run marginal cost.

Q. **Do Enron's witnesses dispute that there is excess capacity in PJM and surrounding areas that will hold prices below long-run marginal cost for the next several years?**

A. No, they do not. The generation supply and demand balance is not addressed at all in their testimony, despite Dr. Bohi's agreement that "the market price for energy and capacity may be above or below long-run marginal cost because of temporary shortages or surpluses of capacity."

Q. **What basis do these witnesses give for using long-run marginal cost as a benchmark for the retail Energy and Capacity Cap?**

A. Mr. Slater explains his calculation as follows: "By comparing the long-run marginal generation cost with the equivalent 100 percent load factor generation credits from the Partial Settlement and the Enron Plan, one should be able to see whether either of the proposals would allow a new generation competitor to enter the market. That is, if the generation credit for a given class is below the long-run marginal cost, one could reasonably assume that new generation would not enter the market."

Q. **Do you agree with this rationale?**

A. No. Generators will, or will not, enter the market on the basis of the market price of generation. This will be set in the wholesale bulk-power market, consisting of the PJM

Exchange and bilateral contracts. This is wholly unrelated to the retail Energy and Capacity Cap. All loads must be supplied reliably by some retailer, including the PLR. All retail suppliers must meet the PJM capacity requirement. Thus, the wholesale demand for energy does not depend on whether the Energy and Capacity Cap is at, above, or below the retail market price of generation. Competitive wholesale prices will be at the level necessary to meet this demand and will be determined by competition among suppliers including, once it becomes relevant, the suppliers of new generation. Thus, the conditions in the generation supply market are unrelated to the level of the Energy and Capacity Cap. Hence, Mr. Slater's reliance on the relationship between the level of the Energy and Capacity Cap and the cost of new generation is wholly incorrect.

Q. Have you also reviewed Mr. Slater's estimate of the long-run marginal cost of generation contained in his Exhibit KJS -4?

A. Yes. I note, as a preliminary matter, that my ability to review it is limited by the complete absence of any discussion of sources and underlying assumptions. However, even the review that I have been able to make shows that the analysis contains errors and biases that make it an unreliable estimate of long-run marginal cost.

Q. What errors and biases does it contain?

A. Let me first note that Mr. Slater simply assumes that the long-run marginal cost will be the cost of a modern combined cycle unit. My analysis showed that in PJM, unlike the New York and New England Power Pools, the existing surplus of baseload capacity means that the most cost effective new capacity to build is not a combined cycle unit, but rather is a combustion turbine (CT). Because new CTs set the capacity price beginning in 2001 and energy is provided primarily from existing units and imports, the market price need not rise to the level that justifies a new combined cycle unit through at least 2008.

Turning to the specific assumptions identified in Exhibit KJS-4, Mr. Slater's capital cost appears reasonable for the type of facility that he models -- a combined cycle unit. However, the annual fixed-charge rate that he uses is unreasonably high. I suspect that he used a nominal fixed charge rate rather than the real fixed charge rate that would have been appropriate. Further, in converting the capital cost to a dollars per kWh figure, Mr. Slater made two additional errors. First, he assumed a 100 percent capacity factor. No real-world unit is 100 percent available. Second, he grossed up the capacity-related cost for an 18 percent reserve margin. Since his stated purpose is to determine the required market revenues of a new entrant, this is improper, since the generation entrant does not pay for reserves. Further, even if a reserve margin gross-up was appropriate, which it is not, the correct amount would have been based on the cost of reserve capacity, which cannot exceed the lower cost of a CT.

Base-year fuel cost appears to be overstated for two reasons. First, the heat rate used is higher than the current state of the art. Second, the fuel price itself is higher than in any of the 1999 forecasts available to me, such as DRI, EIA, and GRI. In addition, Mr. Slater overstates the level of gross receipts tax (GRT) by applying 5 percent GRT, rather than the correct level of 4.4 percent. Further, no allowance is made for fixed O&M. Taking all of these elements together, Mr. Slater's 1999 forecast is higher than the combined cycle costs that I used in my analysis (PECO Statement 6-R). This further exacerbates the incorrect assumption that long-run marginal cost is even relevant to the early years of retail competition.

Most importantly, he assumes a 1.3 percent per year escalation. This assumption is unreasonably low and thus allows Enron to justify Energy and Capacity Caps in later years that are unreasonably low.

Q. Does Mr. Slater provide any basis for escalating long-run marginal cost at only 1.3 percent per year?

A. No, none whatsoever. It is, to say the least, surprising to assume an escalation in the cost of power from new facilities that is well below the rate of inflation without any justification whatsoever.

Q. Does any other Enron witness justify this low escalation rate?

A. No. However, it should be recalled that, whatever may be Mr. Slater's logic for his calculation, the actual use that Enron makes of it is to compare it to the Energy and Capacity Caps in the Partial Settlement and the Enron Plan. In the context of discussing the Enron Plan, Dr. Bohi defends the low rate of increase by saying that "This very moderate increase, or even a moderate decrease in some years would be expected due to the efficiencies as the competitive market takes hold and strengthens." However, the competitive market he is referring to, which presumably is the electricity retailing market, has nothing to do with Mr. Slater's calculation or, more generally, with the wholesale price of electricity. Mr. Slater's long-run marginal cost is composed almost entirely of two elements: the cost of natural gas and the cost of a new combined cycle unit. Both the natural gas market and the power equipment market are highly competitive and have been so for a number of years. Growth in competition in electricity retailing will not have any appreciable effect on these already competitive markets.

Q. What would be a more appropriate rate of escalation in Mr. Slater's long-run marginal cost estimate?

A. Approximately two-thirds of his cost is for natural gas fuel. The 1999-2008 escalation rate in the DRI forecast that I (and OCA's witness) relied upon, and which is representative of the forecasts I have seen, is 4.16 percent per year. It may be that some increase in efficiency may somewhat erode the effect of fuel escalation. However, the new generation of combined cycle plants is by now a relatively known technology with limited potential for further efficiency gains. Moreover, more efficient units also are likely to cost more; hence there is a tradeoff between gains that reduce capital costs and those that increase the thermal efficiency of the unit. Overall, I believe that it is not reasonable to assume an escalation rate that is less than the rate of inflation, particularly in view of the expectation that fuels prices will increase at a rate above inflation.

Q. What is the consequence of this underestimation of the rate of increase in long-run marginal costs?

A. Enron uses long-run marginal cost as its proxy for market prices. Dr. Bohi compares this market price forecast to the Energy and Capacity Caps in the Partial Settlement and the Enron Plan and concludes that the latter are more reasonable. Since Enron's escalation in long-run marginal cost is understated, and in turn the escalation in the delivered cost of power is understated, Dr. Bohi's conclusion is likely to be invalid.

I also should note that, if indeed Enron is correct that electricity prices will increase at only 1.3 percent per year, PECO has significantly overstated the value of its generation and consequently understated its stranded costs. Mr. Slater's estimate of market prices. while much greater than likely market clearing prices during the near term period of surplus capacity, is essentially identical to the forecast of PECO's revenues per kWh generated that I sponsored in PECO Statement No. 6-R and Exhibit WHH-6. However, the Enron forecast of price escalation thereafter is much lower. If market price escalation actually were to be only 1.3 percent per year, then PECO's generating revenues over the 2001-2015 period would be reduced by amounts increasing to approximately $800 million per year. The effect on its stranded cost, computed on an after-tax basis as of September 1, 1998, would be an increase of approximately $1 billion (as shown in Exhibit WHH-10). Of course, a continuation of this low level of price escalation thereafter would increase PECO's stranded cost by still larger amounts.

Q. Have you tested whether his conclusion is valid based on a more reasonable estimate of market prices?

A. Yes. Exhibit WHH-11 compares the Energy and Capacity Caps of the Enron Plan to the delivered cost of power based on the market price analysis I sponsored in PECO Statement 6-R. The forecasts are taken from Exhibit WHH-9 and show the delivered costs for 60, 70, 80 and 100 percent load factors based on the DRI fuels price forecast.

The Energy and Capacity Caps in the Enron Plan are well above the market price in early years but below it in later years. Because Mr. Slater focuses on a 100 percent load factor, I will begin with this result. In 1999, the Enron Cap is nearly 1¢ per kWh above the market price forecast (Exhibit WHH-11). It then falls progressively, and is below the market price forecast for the last three years. For lower load factors, Enron's Cap drops below the market price forecast in successively earlier years. For the 60 percent load factor aggregation, it is below the market price in every year beginning in 2001; for the 70 percent load factor aggregation it is below in every year beginning in 2002; and, for the 80 percent load factor aggregation it is below for all years beginning in 2004.

Q. What is the consequence of a pattern of Energy and Capacity Caps that are well above the market price in early years but below it in later years?

A. In the early period, the Enron Plan would, no doubt, achieve Enron's desired objective of making entry into electricity retailing profitable. Also, a substantial proportion of customers would likely move to alternative suppliers. However, the problem with the Enron Plan arises as a consequence of a too low cap in later years. If, as my forecast indicates, the Energy and Capacity Cap falls below the cost of acquiring and delivering power, then the competition that was established during the period of a very generous Cap will fail. Competitive retailers will exit the market and most customers will return to the default service of the PLR.

This scenario can be contrasted to the effect of the Partial Settlement Energy and Capacity Cap. In the early years, with Caps that closely track expected market prices, customers will be protected from paying above market prices. As I explained in my rejoinder testimony, if prices are above the forecast, customers do not pay any more and stranded cost is not over-recovered since the higher price received by PECO's generation is offset by PECO's higher purchase cost as a PLR. If actual retail prices are lower, customers will pay less and stranded costs will be under-recovered. I accept that these tight price caps will make it harder to compete for customers than if Caps were higher. However, as Mr. Freeman's testimony concerning experience with the pilots in Pennsylvania and elsewhere demonstrates, competition should still occur. As the Partial Settlement Caps become more generous, entry into retailing will become still more attractive.

In the last three years of the Partial Settlement Caps, the "headroom" between the market price and cap becomes quite large. This can be thought of as providing insurance that retail competition will remain viable even if wholesale prices prove significantly higher than expected. Alternatively, if prices are at the forecast level, the size of the headroom virtually assures that the competitive market will clear at prices below the cap. This will mean that the present value of generation payments will be below the sum of the CTC/ITC and the Energy and Capacity Cap. It also will mean that, by the end of the transition period, the substantial majority of customers will have moved to retailers willing to sell at a price lower than the Cap. It is particularly important that competition is vigorous at the end of the transition period, since only vigorous competition will assure that the benefit of terminating the CTC/ITC payment will go to customers rather than their suppliers.

Q. In your summary, you stated that you would respond to Dr. Bohi's comments on the relative consequences of having PECO versus Enron as the PLR. To what were you referring?

A. Dr. Bohi asserts that PECO will have an incumbency advantage that will make it difficult for other suppliers to compete (p. 13). He further contends that PECO will have an incentive to retain PLR customers whereas Enron will not (p. 16) and thereby concludes that the Enron Plan's proposal that PECO not be allowed to market under its own name in its service area is a pro-competitive advantage of the Enron Plan (p. 17).

Q. Do you agree with these conclusions?

A. No. Under the Enron Plan, Enron becomes the incumbent and the sole point of contact with PLR customers. Any incumbency advantage that PECO might have will quickly pass to Enron. Thus, if incumbency advantages are a competitive problem, they are equally burdensome under the Enron Plan.

Second, Dr. Bohi asserts that Enron will desire to move customers away from PLR status because of its undertaking to not mark up its cost to serve them, whereas PECO would seek to retain them. Enron seeks to have the matter both ways. On the one hand, Enron argues that the Partial Settlement's Energy and Capacity Cap is too low, such that serving customers is unprofitable. On the other hand, Enron asserts (but without any evidence) that PECO would seek to retain as much of this unprofitable load as possible. Clearly, if the Cap price is in fact below the market price of generation, it would be in PECO's interest to move customers off of the capped rate into the competitive sector.

Third, the suggestion that Enron's requirement that PECO be forbidden from selling to competitive customers using its own name is pro-competitive is not consistent with adoption of the Enron Plan. Under the Enron Plan, Enron Energy Services Power is the incumbent. PECO no longer has a basis for any contact with what are now Enron's customers. Yet, Enron would forbid PECO's use of its own name as a competitive marketer. At the same time, EPMI would remain free to use the Enron name -- the name of the incumbent supplier -- in marketing. If Enron wishes to be consistent in its position, Enron's subsidiaries should similarly be barred from using the Enron name in any area in which it is the incumbent.

Q. Does this conclude your testimony?

A. Yes.

Estimated Impact of Enron's Price Escalation on Generating Revenues

Year	Energy Output (MWh)	WHH-6 (¢/kWh)	WHH-6 (Nominal $)	1.3% Escalation Rate (¢/kWh)	1.3% Escalation Rate (Nominal $)	Decrease in Revenues (Nominal $)	Decrease in Revenues (Sept. 98 $)
2001	40,277,982	3.26	1,313,062,213	3.26	1,313,062,213	0	0
2002	40,561,660	3.39	1,375,040,274	3.30	1,339,500,148	(35,540,126)	(24,748,630)
2003	40,847,336	3.53	1,441,910,961	3.35	1,366,470,400	(75,440,561)	(48,324,525)
2004	41,135,023	3.69	1,517,882,349	3.39	1,393,983,652	(123,898,697)	(73,006,232)
2005	41,333,593	3.83	1,583,076,612	3.43	1,418,922,059	(164,154,553)	(88,976,769)
2006	41,533,121	3.98	1,653,018,216	3.48	1,444,306,595	(208,711,621)	(104,064,076)
2007	41,733,612	4.14	1,727,771,537	3.52	1,470,145,254	(257,626,283)	(118,161,195)
2008	41,935,071	4.31	1,807,401,560	3.57	1,496,446,174	(310,955,386)	(131,193,795)
2009	42,137,502	4.49	1,891,973,840	3.61	1,523,217,600	(368,756,240)	(143,114,980)
2010	42,340,911	4.67	1,977,320,544	3.66	1,550,467,996	(426,852,547)	(152,389,168)
2011	42,545,302	4.87	2,071,956,207	3.71	1,578,205,907	(493,750,301)	(162,148,934)
2012	42,750,679	5.08	2,171,734,493	3.76	1,606,440,024	(565,294,469)	(170,770,152)
2013	42,957,047	5.29	2,272,427,786	3.81	1,635,179,235	(637,248,552)	(177,082,885)
2014	43,164,412	5.51	2,378,359,101	3.86	1,664,432,621	(713,926,480)	(182,495,318)
2015	43,372,778	5.75	2,493,934,735	3.91	1,694,209,351	(799,725,384)	(188,048,391)

Discount Rate 0.0871

NPV of Difference on September 1, 1998 (1,764,525,047)

NPV of After Tax Difference on September 1, 1998 **(1,058,715,028)**

Comparison of Enron's Cap to Average Retail Price
Assuming Different Load Factors
Using DRI Fuel Forecasts

Year	Enron's Cap (¢/kWh)	60% Load Factor		70% Load Factor		80% Load Factor		100% Load Factor	
		Average Retail Price (¢/kWh)	Difference (¢/kWh)	Average Retail Price (¢/kWh)	Difference (¢/kWh)	Average Retail Price (¢/kWh)	Difference (¢/kWh)	Average Retail Price (¢/kWh)	Difference (¢/kWh)
1999	3.48	2.68	0.80	2.62	0.86	2.58	0.90	2.51	0.97
2000	3.48	3.08	0.40	2.98	0.50	2.91	0.57	2.80	0.68
2001	3.54	3.66	(0.12)	3.50	0.04	3.37	0.17	3.20	0.34
2002	3.63	3.83	(0.20)	3.66	(0.03)	3.53	0.10	3.35	0.28
2003	3.72	4.00	(0.28)	3.82	(0.10)	3.69	0.03	3.51	0.21
2004	3.81	4.17	(0.36)	3.99	(0.18)	3.86	(0.05)	3.66	0.15
2005	3.89	4.35	(0.46)	4.16	(0.27)	4.02	(0.13)	3.83	0.06
2006	3.98	4.53	(0.55)	4.34	(0.36)	4.19	(0.21)	3.99	(0.01)
2007	4.08	4.72	(0.64)	4.51	(0.43)	4.36	(0.28)	4.15	(0.07)
2008	4.16	4.91	(0.75)	4.70	(0.54)	4.55	(0.39)	4.33	(0.17)

R-00973953, R0097395-3C0001-C0007 et al

PECO STATEMENT NO. 13-E

Phila 11/18/97

E.H.

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

TESTIMONY

OF

WILLIAM F. SUNDERMEIR

REGARDING THE ENRON CHOICE PLAN

Regarding Enron's Proposed Electric Delivery Service Tariff,
Proof of Revenue, and Unbundling of Metering, Billing, and Customer Service

November 7, 1997

TABLE OF CONTENTS

TESTIMONY OF WILLIAM F. SUNDERMEIR

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your full name and address.

A. William F. Sundermeir, 2821 Bayland Drive, Ocean City, NJ 08226.

Q. Did you previously prepare testimony in this proceeding?

A. Yes. I submitted PECO Statement Nos. 13 and 13-R.

Q. Mr. Sundermeir, what is the purpose of your testimony?

A. The purpose of my testimony is to respond to certain features of the Plan. Enron has proposed ("Enron Plan") as an alternative to the Partial Settlement. Specifically, I will:

- Present a critique of the "Electric Delivery Service Tariff" (the "Enron Tariff") that Enron has proposed through the testimony of Harry J. Kingerski;
- Respond to certain contentions of Enron witness Yolanda Lopez regarding the proofs of revenue supporting the Partial Settlement; and
- Present a critique of the proposed unbundling of so-called revenue cycle services (metering, billing, collection, and customer service) by Enron witness Paul D. Reising.

II. CRITIQUE OF ENRON'S PROPOSED ELECTRIC DELIVERY SERVICE TARIFF

Q. Please describe Enron's approach to developing the proposed Electric Delivery Service Tariff.

A. Enron witness Harry Kingerski explains Enron's approach in his testimony. Mr. Kingerski states that Enron has completely recast PECO's current Tariff so that competitive electric generation suppliers (EGSs) and not current PECO customers (whom Enron refers to as "end-users") are the recipient of services. That is, EGSs, and not the ultimate users of electricity, are PECO's customers under the Enron Tariff. EGSs would obtain regulated "wires" distribution services from PECO as agents for their energy supply customers, and would in turn provide functions directly to consumers on an unregulated basis including some - - but perhaps not all - - "revenue cycle" services such as metering, meter reading, billing, and customer service.

Q. Does PECO agree with this approach?

A. No. As explained by Mr. Brian D. Crowe in his testimony, PECO does not believe that it is in the public interest to structure the tariff to enable unbundling of so-called "revenue cycle services." PECO's position remains that these services should not be provided competitively but should be provided by the regulated distribution company. For purposes of my critique of the Enron Tariff, however, I have assumed Enron's proposed tariff structure.

Q. What else does Mr. Kingerski say about Enron's approach to the development of the Enron Tariff?

A. Mr. Kingerski claims that his goal was to minimize changes to PECO's Tariff and that most of the changes "serve only to introduce the concept of electric generation suppliers ("EGSs") into PECO's System."

Q. Do you agree that the changes Enron has proposed serve this limited purpose and have no other impact?

A. No. As I will demonstrate in detail in the following testimony, under the guise of merely interjecting EGSs into the mix, Enron has made numerous proposals to handicap PECO and advantage EGSs to the detriment of consumers. Under the Enron Tariff, numerous protections and rights that customers currently enjoy, and have enjoyed for many years, will no longer be available. As such, the Choice Plan is anti-consumer and should be rejected by the Commission.

In fact, as many of Mr. Kingerski's proposed tariff changes contravene the Competition Act or Chapter 56 consumer protections, undermine reliability, and restrict or eliminate customer options, they are not, as he contends, "in line with the objectives and purpose of the Act." For example:

- Enron would force customers to deal directly with EGSs instead of PECO for virtually all matters, evading Commission regulation, raising public safety concerns and limiting customer choice;

- EGSs would be able to rebundle PECO's regulated non-generation related charges and effectively charge "whatever the market will bear," thus subverting the Competition Act's non-generation charge rate caps and violating the Act's intent;
- EGSs would not have to provide all the information on customer bills required by Chapter 56;
- EGSs would be able to charge end-users more than the late payment charges contained in our current tariff;
- EGSs would take away customers' right to choose among available rate schedules under which customers would take distribution service and the corollary assistance PECO provides upon request to help customers select the most favorable distribution rate classification;
- EGSs could discontinue service on five days notice and jettison the customer to Default Service provided by the provider of last resort;
- Default Service options would be substantially limited for industrial customers;
- Universal Service (i.e. CAP Rate) customers would lose their ability to shop for energy if they wanted the benefits of lower universal service rates;
- Enron would remove important load management and conservation provisions such as master metering, the Cooling Thermal Storage Service Rider, and the Electric Vehicle Charging Rider;

- Enron would deny PENN DOT and the City of Philadelphia the current benefits they receive through the "outage allowance" on their street lighting bill;
- Enron would limit the application of the Employment and Economic Recovery Rider, which encourages businesses to increase employment and promote economic development;
- Enron would eliminate Rule 4.6, and the Economic Efficiency and the Incremental Process Riders, all of which provide the flexibility to discount rates so as to promote economic development;
- Enron would limit the residential Solar tariff option by eliminating the Company's ability to charge for a metering option;
- Enron would eliminate the Transformer Rental, Curtailment HT, and Off Peak Riders, thus not only restricting customer choice, but also causing significant increases in customers' bills or investments.
- Enron would eliminate PECO's ability to sell supplementary, back-up and maintenance power to self-generators, thus not only limiting customer choice but also violating provisions of federal law; and,
- Enron would remove benefits that PECO customers currently enjoy under the Night Service Riders, the Temporary Service Rider, and Capacity Reservation Rider.

I will describe these problems in greater detail later in my testimony.

Q. Are consumers the only victims of the changes Enron has proposed in its Tariff?

A. No. Enron has also included some revisions that would unfairly benefit EGSs and harm PECO. Although Enron has recast the tariff so that the EGS, and not PECO, is the ***provider*** of certain services and the EGS, and not the customer, is the ***recipient*** of certain services, Enron's revisions allow EGSs to avoid certain costs and obligations to the disadvantage of both customers and PECO. The Commission should reject Enron's attempt to unlevel the playing field in favor of EGSs by rejecting the Choice Plan.

1. Provisions In Enron's Tariff That Are Anti-Consumer

Q. Rule 17.2(b) of Enron's proposed Tariff provides that an EGS may either separately state PECO charges for regulated distribution service or incorporate them into the EGS billing. Is this acceptable?

A. No. If an EGS does not separately state all charges, the EGS has essentially rebundled the bill, this violates the spirit of the Competition Act because it makes it impossible for consumers to determine who had charged what. This deprives consumers of the information needed to choose an EGS through meaningful comparison of EGS offerings. In marked contrast, the Partial Settlement would assure unbundled billing, thus providing consumers the information they need to make informed choices.

Q. Does the Enron Tariff contain any provision requiring an EGS to comply with the rate caps when the EGS' bill includes PECO's regulated services?

A. I can find none. Enron Rule 17.2, which covers billing, contains no provision requiring that the EGS' rebundled bill contain charges that comply with the rate caps. My interpretation of the rule is that an EGS could charge consumers as much as it wants through rebundling of the bill, effectively turning regulated pricing for non-generation service into unregulated pricing. The Partial Settlement, however, clearly requires PECO to observe the Competition Act's mandated rate caps.

Q. Rule 5 of PECO's current tariff contains consumer credit-protections such as limits on customer deposits, return of deposits and interest rate limitations on finance charges. Does the Enron Tariff include similar safeguards for consumers?

A. No. Enron's proposed Rule 24 is similar, but would only apply to consumers receiving default service. Accordingly, other consumers would be subject to the unregulated credit policies of their EGS. The Enron Tariff contains no provision requiring EGSs to comply with PECO's current consumer credit protections and fails to describe any credit protections for customers who choose an EGS. Enron, therefore, is seeking to deprive consumers of the significant credit protections they now have under the current PECO Tariff and would continue to have under the Partial Settlement.

Q. To focus on some specific examples, Enron's proposed Rule 17.1(b) provides that the EGS must pay a late payment charge of 1 ½% to PECO if not paid by the due date. Does Enron limit late payment charges for consumers?

A. Enron only specifies limitations on late payment charges for Default Service customers. As no such protection exist for any other consumers, an EGS could impose higher charges on such customer in contravention of their current rights and their continued rights under the Partial Settlement.

Q. Proposed Rule 17.2(d) gives each EGS the right to establish its own policies with regard to returned check charges, interest on late payments, customer deposits, payment terms, remittance termination policies and the like. As these policies would apply to monies collected for PECO's regulated services is it appropriate to allow each EGS such options?

A. No. The Commission's Chapter 56 consumer protection regulations already cover many matters listed in this rule. In general, the Enron Tariff is silent on whether an EGS will have to comply with provisions in Chapter 56, or pay any fines for failure to comply with those provisions. As such, Enron's promise to comply with Chapter 56 purportedly contained in its application to be a licensed EGS in Pennsylvania is conspicuously absent in its proposed tariff provisions.

Q. Enron's proposed Rule 17.2(e) sets forth a list of informational items that an EGS must include on a consumer's bill. Is this list complete?

A. No. Enron has omitted vital information for consumers required by Chapter 56, including: (1) whether the meter reading is an estimate; (2) total amount of credits to the bill; (3) statement with regard to procedure for registering a complaint or a question; and (4) late charges.

Q. Enron proposes to automatically shift bill payment responsiblity to a landlord when a tenant closes an account (Rule 17.2(f)). Is this allowed?

A. No. PECO cannot initiate service unless specifically requested by an applicant. To protect landlords' legitimate interests, such a shift in payment responsiblity cannot be made without the landlord's consent.

Q. Rule 20.1 in PECO's current tariff requires that a customer who wishes to discontinue service must give PECO seven days written notice. How does the Enron Tariff address notice to discontinue service?

A. Enron has completely reversed PECO's Rule 20.1. Enron's proposed Rule 20.1 requires that the EGS give PECO seven days notice whenever the EGS wishes to discontinue service regardless of the wishes of the customer. Furthermore, under Rule 18.1 of the Enron Tariff, an EGS *can* discontinue service to a consumer on five days notice regardless of whether or not the consumer wants service discontinued. This proposed rule, which gives the EGS the right to discontinue a consumer's service whenever it is advantageous to the EGS, could have a serious impact on consumers who, on very short notice, would be forced to seek another EGS, quite possibly at a higher price. Five days notice would likely not be sufficient time for the consumer, the former EGS, a potential new EGS (or EGSs) and PECO to complete transfer of the consumer's service. As I will explain later, the situation would be further complicated if another EGS (or EGSs) provides one or more of the non-wire services Enron proposes to unbundle. Obviously the Enron proposal would therefore pose difficulties for consumers not presented by the Partial Settlement.

Q. Enron's proposal contains a new rate - Rate DS Default Service. Do you have any comments on this rate?

A. Yes. Customers served under Enron's Rate DS, would be charged Enron's proposed energy prices regardless of the actual prevailing market prices; the default service provider may ***not*** charge less. In contrast, the Partial Settlement contains caps for energy and capacity and allows default services customers to pay ***less*** if the market is trading at a lower price. Accordingly, only under the Partial Settlement would customers rejected by a competitive EGS still receive the benefits of competition.

Moreover, the Standard Default Service ("SDS"), which is a month-to-month service for customers who need service to bridge a gap between competitive EGSs, would not even be available to industrial customers. Rather, such consumers may ***only*** receive Transitional Default Service ("TDS"), with a minimum term of twelve months. This seriously limits an industrial customer's opportunity to shop for a better deal, especially when coupled with an EGS' right under Rule 18.1 to terminate service on only five days notice. Notably, the Partial Settlement contains no such unreasonable limitations on an industrial customer's ability to participate in competition.

Q. Mr. Sundermeir, has Enron adopted the Universal Service provisions contained in the Partial Settlement?

A. No. As the Enron Plan does not provide for the portability of all universal service benefits, Enron has disregarded a key provision of the Partial Settlement that: "the benefits of universal service programs shall not be affected by whom the customer selects as its generation supplier."

Q. Please explain how Enron has precluded such portability.

A. Although the Enron Tariff provides for discounted distribution charges and transition charges under the CAP rate schedules, it does not provide for generation discounts unless the CAP customer takes service under Default Service. Under Default Service, however, a customer does not have the ability to shop for generation. Instead, CAP customers who wish to receive the intended rate discount on the generation component of their bill must surrender their right to shop for generation supply. In its response to PECO's interrogatory XIII-6, Enron confirmed this, stating that a CAP customer who desires to shop for competing generation supply "is no longer eligible for CAP rates and delivery occurs under Schedule R."

Q. How does PECO propose to ensure portability of Universal Service benefits when the CAP customer selects an EGS?

A. As stated in our response to Enron's interrogatory VIII-7, "CAP Rate customers will be given the applicable credit for the generation component directly by PECO, regardless of their energy supplier."

Q. Rule 11.1 in PECO's current tariff allows the consumer to select a rate when one or more rates are applicable to its service. Enron proposes shifting the choice to the EGS. Is this in the customer's best interest ?

A. No, I do not believe so. Because a consumer is ultimately responsible for paying a bill that would contain charges for PECO's regulated services, the consumer should have the right to be served under the most advantageous rate.

Q. Doesn't Mr. Kingerski in his testimony claim that PECO is wrong in its conclusion that the consumer would not be entitled to select a rate under Enron's proposal?

A. Yes, he does. Mr. Kingerski's actual response, however, is that the EGS, and not consumers, should make the selection. Restructuring should be about adding choices, not taking them away. The consumer, and not the consumer's EGS, should therefore have the right to make choices about regulated rates. This revised Rule 11.1 is an example, however, of how Enron, which often touts the value of customer ***choice***, would unfairly and needlessly deprive customers of a very important choice.

Q. **Enron also proposes eliminating Rule 11.2, which obligates PECO to assist a customer in selecting the most advantageous rate.**

A. This is another example of an Enron revision that is not in the consumer's best interest. Mr. Kingerski claims this rule is unnecessary because "EGSs are competing to satisfy the end-user." If Mr. Kingerski is suggesting that PECO should not have both the right and obligation to satisfy consumers with respect to services that will continue to be regulated, his suggestion is absurd on its face.

Mr. Kingerski also attempts to question the importance of the current rule by stating that PECO may refuse to provide such assistance even when requested. This is not true. The customer must request assistance because in many instances, service circumstances may change without PECO's knowledge. Currently, and under the Partial Settlement, however, PECO does not and cannot refuse to provide assistance if a customer requests it.

Q. **Enron also proposes to eliminate PECO's Rule 11.3. Is this in the best interest of the consumer?**

A. No. This rule provides customers the flexibility to change rates, to switch from an interruptible rate to a firm rate, or to modify the terms of a contract in certain circumstances. Again, it is difficult to understand why Enron would propose the elimination of a tariff provision that gives customers important choices. Mr. Kingerski offered no justification in his testimony for eliminating this rule, but it seems to be yet another example of Enron's desire to have the EGS, rather than the consumer, make virtually all of the decisions for the consumer.

Q. In Enron's proposed Rule 13.1, Enron eliminates the existing provision that allows PECO or a landlord the option to individually meter tenants. Should this option be eliminated?

A. No. When there is a requirement to individually meter tenants, the landlord should have the flexibility to select the source of the metering service as PECO's tariff allows.

Q. But Mr. Kingerski states in his testimony that elimination of the provision gives the landlord more options. Is this true?

A. No. The current tariff provision gives the landlord the right to individually meter the tenants. It does not restrict the landlord's options in selecting how this should be done. Again, under the guise of supposedly doing nothing more than introducing the EGS into the mix of relationships, Enron would actually eliminate important options that consumers currently have available.

Q. Enron has also eliminated the provision in Rule 13.1 that allows master metering of heating and cooling systems when it is in the interest of energy conservation. Does this seem reasonable?

A. No. In many instances tenants are provided space heating, water heating and air cooling from a central system. If it can be shown that a central system is more efficient than such facilities in each tenant's area, it is appropriate to master meter the central systems to promote energy conservation.

Q. On this issue, Mr. Kingerski claims in his testimony that the master metering of heating/cooling systems can be waived at the sole discretion of PECO. Is he correct?

A. No. Mr. Kingerski has mixed and therefore misunderstood two provisions in current Rule 13.1. The provision that allows PECO to waive the requirement for individual metering is only applicable to dwelling units when it can be shown that such waiver will not significantly impact consumption. This provision has nothing to do with master metering of heating/cooling systems.

Q. In its proposed Rule 15.3(d), Enron has eliminated the phrase, "for each hour billed based on the PJM billing rate." Could this result in a rate increase to a customer on the Large Interruptible Load Rider (LILR)?

A. Yes. The adjustment described in PECO's current Rule 15.3(d) is only applicable to the kilowatt-hours associated with the customer's interruptible load. Enron's proposal, however, expands this adjustment to include all on-peak kilowatt-hours, which could substantially increase the customer's bills.

Q. **Rule 21.7 in PECO's current tariff allows PECO to charge for services requested by consumers that are not included in the tariff. Enron has changed this provision such that any request for service would have to come from an EGS. Is this reasonable?**

A. No. For example, under the current rule, if a consumer's privately-owned poles and wires are damaged in a storm, the consumer may request that the Company restore service. Enron's structure would deprive consumers of the right to arrange for this type of service on their own property without the involvement or approval of an EGS. Again, Enron has proposed a revision that unjustifiably eliminates a consumer's choice.

Q. **Are you familiar with Mr. Kingerski's testimony regarding Enron's elimination of the outage allowance in Rate SL-P?**

A. Yes. Although Mr. Kingerski asserts that PECO is wrong in claiming that the outage allowance in Rate SL-P would no longer be applicable under the proposed Enron Tariff, it is Mr. Kingerski, not PECO, that is wrong. As long as PENN DOT and the City of Philadelphia ("City") are PECO street lighting customers under Rate SL-P, the outage allowance must remain in the tariff or their bills will increase. Notably, under the City's current Rule 4.6 contract, the City will remain a customer under Rate SL-P through at least June of the year 2000.

Q. Mr. Kingerski claims that Enron's proposed tariff promotes competition and economic development better than the Partial Settlement. Are Mr. Kingerski's claims well-founded?

A. No. It is Enron, not PECO, that has proposed to eliminate existing provisions that promote competition and economic development. For example, Enron would eliminate Rule 4.6 and the Economic Efficiency and Incremental Process Riders meaning PECO would not be allowed to foster economic development by offering eligible customers distribution service at mutually agreed upon rates. Similarly, Enron would limit the applicability of the Employment and Economic Recovery Rider, which was developed to encourage businesses to expand or move to Pennsylvania, to PECO's regulated charges. It is PECO's position that the discount provided in this rider should be prorated over all of the various charges including energy, as growth and economic development are beneficial to all parties. As Enron apparently is more interested in advancing the interests of EGSs and restricting PECO even to the detriment of consumers, it is not surprising that their proposed Tariff includes no such provision.

Q. Are there other examples of this apparent Enron strategy?

A. Yes. Mr. Kingerski's proposal to eliminate the Cooling Thermal Storage Rider, the thermal storage provisions of Rate GS, and the Electric Vehicle Charging Rider are other examples. The Cooling Thermal Storage Rider encourages the development and use of thermal storage in summer months to lower demands on electric systems and conserve energy. The thermal storage provisions of Rate GS serve the same purposes for both heating and cooling. Similarly, the Electric Vehicle Charging Rider was introduced to improve the environment by encouraging the development and use of electric vehicles. Although these riders may not promote the interests of EGSs, as they enable PECO to provide benefits to customers that EGSs may not be able to provide, they do promote the general welfare and therefore consumers' interests. The Enron Plan deprives society of their benefits.

Q. Mr. Kingerski also specifically supports the elimination of the Transformer Rental Rider. Would this be beneficial to consumers?

A. No. This rider has not been available to new customers since October 15, 1963. Since then customers served under the rider have had the option to buy transformers or rent them from another source, but many have chosen to continue renting from PECO. Elimination of this rider would force these customers to obtain transformers from another source, which could be quite costly.

Q. In his testimony, Mr. Kingerski also challenges PECO's assertion that Enron's proposed elimination of a monthly meter charge for a second meter for Rate RS customers would eliminate the two meter option for these customers. Is he correct?

A. No. PECO might have to provide both meters, as an EGS does not have to do so under the Enron Plan. Without the monthly meter charge for a second meter, PECO would not be able to provide the second meter unless it did so for free.

Accordingly, Enron's proposal effectively eliminates the two meter option for some customers.

Q. Mr. Kingerski also continues to advance Enron's position that the Auxiliary Service Rider should be limited to transmission and distribution service only. Do you have any comment?

A. Enron's proposal unambiguously violates the Public Utility Regulatory Policies Act, a federal law requiring electric utilities to supply supplementary, back-up and maintenance power to Qualifying Facilities. Furthermore, PECO's unbundling of this rider under the Partial Settlement also allows consumers to secure energy from an EGS for supplementary, back-up or maintenance purposes. Again, in this instance the Partial Settlement preserves choice for consumers, but Enron's Plan deprives customers of a federally-mandated choice.

Q. Mr. Kingerski also questions PECO's claim that it would be a mistake to require customers experiencing outages to call their EGS instead of calling PECO directly. Would you comment on this criticism?

A. Yes. Mr. Kingerski asserts that having a consumer call its EGS would eliminate the confusion that purportedly would result from having the customer directly call PECO. Yet, even under the Enron Tariff, PECO would continue to maintain a line to directly receive calls regarding hazardous or life threatening situations and the reliability and safety of the system. Under Enron's Plan, how will a customer decide whether to call its EGS or the PECO-maintained phone line? Obviously, therefore, the Enron Tariff does not eliminate confusion -- it creates confusion and the potential for loosing critical responsive time that does not exist under the Partial Settlement.

Q. **Mr. Sundermeir, do you have comments regarding Enron's proposed disposition of certain riders as set forth in Exhibit A to the Enron Tariff?**

A. Yes. I will comment on some of the riders that I have not already discussed:

- Alley Lighting Rider - this rider has already been unbundled as part of the Partial Settlement.
- Curtailment HT Rider - this rider provides significant reductions to the ratchet charges customers served under it would otherwise pay. Its elimination would result in increased bills to specific customers in violation of the statutory rate caps contained in the Competition Act .
- Night Service Riders - there is no generation portion in these riders; therefore, the charges in them should not be, and cannot be unbundled.
- Off-Peak Rider - this rider has been frozen since 1972; however, its elimination could result in rate increases to customers still served under it, in violation of the statutory rate caps contained in the Competition Act.
- Temporary Service Rider - this rider provides for short-term, temporary service to consumers. An example is Christmas tree sellers. Eliminating this rider would harm these types of consumers, as they would have to obtain and pay for permanent service under one of PECO's standard rates.

- Capacity Reservation Rider - this rider must be retained for existing LILR customers.
- Concerning the Economic Efficiency and Incremental Process Riders referenced earlier if, as claimed by Enron, these riders are unnecessary in a fully competitive environment, they will eliminate themselves.

Q. Mr. Sundermeir, what do you conclude regarding Enron's Tariff as it would apply to customers, or "end-users" as Enron calls them?

A. Under the guise of merely interjecting EGS's "into PECO's system," Enron has restructured the tariff so that only EGSs, and not PECO, may offer benefits to consumers. To accomplish this, the Enron Tariff deprives customers of many protections, benefits and options they currently enjoy, and would continue to enjoy under the Partial Settlement. Thus, the Enron Tariff seeks to unfairly benefit EGSs and handicap PECO even at the expense of consumers. In contrast the Partial Settlement ***preserves*** existing regulatory protections and benefits for consumers ***without*** precluding EGSs from offering additional benefits.

2. Provisions in Enron Tariff that Unfairly Advantage Supplier

Q. **Rule 7.2 in PECO Energy's current tariff provides for minimum revenue guarantees under specified circumstances. Has Enron proposed any significant changes to this rule?**

A. No. Unlike in most other provisions, in this rule Enron does not interpose the EGS between PECO and the customer, meaning that a customer will still be responsible for the revenue guarantee. This is another example of Enron's primary goal to unfairly advantage EGSs at the expense of both PECO and consumers. For, when a minimum revenue guarantee must be paid, Enron proposes to let the EGS step aside and allow a direct relationship between the consumer and PECO.

Q. **Enron's proposed Rule 16.2(f) indicates that a competitive meter service provider ("MSP") *may*, upon request, make tests to supply special information with regard to the consumer's service. Is this consistent with PECO's requirement to provide such tests?**

A. No. The present tariff states that PECO will perform such tests when the customer wants them. Apparently, Enron does not believe that customers metered by EGSs should have the right to demand such meter tests.

Q. Rule 18.6 in PECO's current tariff allows PECO to terminate service, without notice, for abuse, fraud or tampering with PECO's equipment. Has Enron proposed a significant change to this rule?

A. Yes. Under Enron's proposed Rule 18.6 and Rule 24.7, PECO could not terminate service if it does not own the meter. This limitation on the Company has potential safety ramifications. People could be at risk of serious harm if an EGS refuses to allow termination, or if termination is delayed.

Q. Enron has proposed a new rate adjustment called the "Other Tax Adjustment Clause." Would you comment on this proposal?

A. Yes. I cannot see any justification to support an adjustment to PECO's rates to recover taxes imposed on an EGS. PECO must recover its own tax liability from its rates and the State Tax Adjustment Clause. To ask consumers purchasing distribution service from PECO to pay a higher rate to recover the tax liability of a third party is unreasonable and unfair.

Q. In applicable rate schedules, Enron has eliminated a provision for "Term of Contract." Is this acceptable?

A. No. The "term of contract" provision imposes a legitimate obligation on the customer so that PECO can be assured of at least partial recovery of its investment to serve that customer. Because Enron, as an EGS, wants to be the "customer," Enron apparently does not want any such obligations.

In addition, elimination of these provisions would allow an EGS to switch between rates on a seasonal basis. For example, an EGS could switch from Rate GS to Rate HT in the summer for certain customers that are eligible for both rates, and then switch back to Rate GS before the winter. This would allow the EGS to avoid the higher Rate HT demand ratchet that would otherwise apply in the eight winter billing months. In the short-run, this injures PECO by depriving the Company of the ability to recover all of its prudently incurred costs and its allowed recovery for stranded investment. In the long-run, all consumers suffer harm; following expiration of the rate cap on distribution charges, PECO may have to raise rates to ensure recovery of its prudently incurred costs.

Q. Mr. Sundermeir, can you please summarize your analysis of those provisions in the Enron Tariff that unfairly advantage EGSs?

A. With respect to each provision I have analyzed, it is clear that Enron has attempted to tip the balance such that PECO has all the obligation and the EGS has all the benefit, often at the expense of customers. In addition to those I analyzed earlier, these provisions are patently anti-consumer. They also reveal that Mr. Kingerski's claim is simply incorrect. Enron has made many changes that injure consumers and that unfairly advantage EGSs at PECO's expense.

Q. Mr. Sundermeir, have you identified any other problems with the Enron Tariff?

A. Yes. I have identified several technical problems with the Enron Tariff. I have listed these problems in the attached Exhibit WFS-13.

III. RESPONSE TO ENRON'S CRITICISMS OF PECO'S PROOFS OF REVENUE

Q. Mr. Sundermeir, do you have any updates to the proofs of revenue?

A. Yes. Attached as Exhibit WFS-14 are revised HT proofs of revenue for the years 1999-2008 (the year 2000 is not included because those rates will remain identical to those in 1999).

Q. Do these revised HT proofs of revenue have a material impact on the Partial Settlement?

A. No, these revisions have no material effect of the Partial Settlement and do not change any of the figures in the Derivation Summaries. The most significant revision was to include approximately $5 million in the Maximum Energy and Capacity Charge revenue which was excluded in the HT proofs of revenue originally submitted in Appendix C of the Partial Settlement.

Q. Have you reviewed the direct testimony and accompanying exhibits of Yolanda H. Lopez concerning the Proofs of Revenue supporting the Partial *Settlement*?

A. Yes, I have.

Q. Can you address the first of the "three areas of concern" raised by Ms. Lopez, beginning on Page 4 of her testimony, which concerns the HT Proof of Revenue for each year?

A. Yes. Ms. Lopez claims that PECO's HT proofs of revenue do not tie to the Derivation Summaries for any of the years for which rates were developed, causing a alleged "$20 to $25 million" shortfall. Although the derivation of Ms. Lopez's figures is unclear, what ***is*** clear is that no "shortfall" exists. On the contrary, the total of the values shown in column six of the HT proofs of revenue for each year (with the exception of the $5 million for 1999 mentioned above) will equal the total values shown on the Derivation Summaries for the same year.

Q. Can you address the second of Ms. Lopez's "areas of concern," which concern the mathematics used to derive the rates and revenues in the Proofs of Revenue?

A. Yes. The rates shown in column five of the proofs of revenue were calculated to greater than four decimal places. The electronic spreadsheet calculation in the proof of revenue multiplies the displayed billing units in column four with the calculated rate, thus producing the revenue shown in column six. The printed version of the spreadsheet, however, shows only the first four decimal places of each rate. Any rounding which would occur in the revenue figures because of rounding the rate after four decimal places would create de minimus differences.

It is noteworthy that Ms. Lopez categorizes this method of rate development as an "area of concern" yet she, or someone under her direct supervision, also used this approach to derive Enron's proposed alternate Generation Credit and CTC/ITC. In the "end block" of every rate class containing a charge in more than a single block, Ms. Lopez derives that block's revenue by multiplying the sales by a rate that requires more than the displayed four decimal places. That is to say, the sales multiplied by her displayed rate will also ***not*** add to the displayed revenue.

Q. Can you address the third of Ms. Lopez's "areas of concern" regarding the sales levels used in the proofs of revenue supporting the Partial Settlement rates?

A. Ms. Lopez indicates that sampling should only be used when accurate actual data are not available. I could not agree more. However, actual billing determinants are not available; thus, sampling is required. Ms. Lopez further indicates concern that sampling may distort the resulting rates and revenue. Aside from the fact that sampling data must be used, Ms. Lopez need not be concerned. The bundled rates and unbundled rates were specifically designed to produce the same revenue from individual customers; thus, there is no possibility that excess revenue can be recovered because the sample does not expand exactly to the universe.

A simple way to prove the truth of this last assertion is to analyze the Partial Settlement rates for the years 2003 through 2005. If Ms. Lopez's contention is true that PECO intends to over-recover revenue through its rate design by using "lower than actual" sales then in every year of the Partial Settlement, PECO should be receiving more revenue than it claims in the proofs of revenue. Yet in the years 2003 through 2005, the sum of PECO's unbundled rates are designed to equal PECO's bundled rates. This would cause exactly the same revenue with unbundled rates as with bundled rates no matter what the level of sales is in the two comparison periods.

Q. Do the rates designed by Ms. Lopez cause intra-class cost shifting?

A. Yes. In the years 2003 through 2005, Ms. Lopez's Default Service rates -- most notably those for Rate HT, PD, and GS customers -- cause lower load factor customers to pay more than they are currently paying on PECO's bundled rates. Conversely, the higher load factor customers pay less than they currently are paying. Although the proofs of revenue may indicate that the total revenues collected from a particular customer class are exactly the same as in 1996, the lower load factor customers will be paying higher rates than they did in 1996. Not only does this violate the rate cap, it specifically disadvantages the type of lower load factor customers that EGSs will be less likely to want to serve.

TABLE OF CONTENTS

IV. CRITIQUE OF ENRON'S PROPOSED UNBUNDLING OF METERING, BILLING, COLLECTION, AND CUSTOMER SERVICES

Q. Mr. Sundermeir, could you comment on Enron's proposed credit for what it calls "non-wires service"?

A. Yes. First, as I stated earlier in my testimony, PECO opposes the unbundling of these services. Notwithstanding PECO's opposition, however, I believe it is important to identify the many flaws in Enron's unbundling proposal, as presented in the testimony of Paul D. Reising. I will also explain how to properly develop such a credit using costs from PECO's recently submitted cost of service study, and appropriate and applicable rate design principles.

Q. Please continue with your critique of Mr. Reising's proposals regarding unbundling of non-wires services.

A. My first concern with Mr. Reising's proposal is that the basic design of providing EGSs "credit for non-wires services" is fundamentally unfair. Mr. Reising identifies seven different categories of cost associated with non-wires services: (1) Metering, (2) Meter Reading, (3) Billing and Collection, (4) Customer Service and Information, (5) Uncollectibles, (6) Sales, and, (7) Lighting-related services. Mr. Reising then calculates credits by using costs in ***all*** seven categories. He asserts that an EGS would get this credit from PECO because PECO supposedly would no longer be providing the non-wires services. That is, he claims PECO would avoid ***all*** of these costs if EGSs were able to provide non-wires services competitively, and EGSs should therefore not have to pay PECO for ***any*** of these costs if they provide the services instead of PECO.

Although designing a credit based on costs is in itself reasonable, under Enron's Tariff, the EGS would receive ***all*** of this credit even if it chooses to provide only ***one*** of the services, a blantantly unfair result. For example, Enron's Rule 14.1 allows an EGS to "utilize" the Company's meters. This means that an EGS could provide meter reading, but not install and maintain its own meter. Rule 14.1, however, does not provide that the credit for non-wires services be reduced in such circumstances, meaning that an EGS would get a credit for something it would not be doing - - installing and maintaining the meter. PECO, on the other hand, would continue to own and maintain the meter, but ***not*** be allowed to recover its costs for doing so.

Nothing in Enron's Tariff precludes this completely unfair outcome with respect to any of the non-wires services. An EGS would get the full credit, calculated using costs of all of the services, yet provide merely a few, or even only one, of the services.

Q. **Mr. Sundermeir, are there problems with Mr. Reising's proposed cost basis for the credit?**

A. Yes, there are. Mr. Reising unbundles non-wires services costs on a total Company cost basis without considering whether the Company would actually be able to avoid the costs in question in proportion to the number of customers served by EGSs. Under the Enron Plan, however, PECO could not shed the costs associated with non-wires services on a proportional basis. For, as Enron's contractor for these non-wires services under the proposed MBC Services Agreement, PECO would have to stand ready to provide metering, billing, and customer services for all Default Service Customers. Moreover, the Enron plan provides that customers may return to Default Service at any time and also allows EGSs to terminate customers on five days notice, forcing customers to return to default service, at least temporarily, if they are unable to sign up with a new EGS in that short time. Accordingly, PECO, which must stand ready to serve a large number of customers at any time, and on as little as five days notice, would be far more likely to continue to incur costs associated with non-wire services at near current levels.

Q. Mr. Sundermeir, with regard to metering and meter reading, can you explain in more detail the primary reason PECO would continue to incur these costs at levels far higher than Mr. Reising assumes would be required even if EGSs were to provide the corresponding non-wires service?

A. Yes. These costs include all of the costs PECO currently incurs to acquire, install, maintain, and read all 1.5 million meters in use on its system. As PECO would still have to stand ready to perform all of those functions for default service customers, it would likely continue to incur the overwhelming majority of these capital and operating and maintenance costs even if EGSs were allowed to perform all or some of them on a competitive basis.

This is true for many reasons. First, under the Enron Plan, EGSs could terminate customers on five days notice for any reason (including the EGS' belief that serving the customer is no longer profitable), or customers could return to default service on their own at any time. Furthermore, an EGS with many metering customers could suddenly go out of business, requiring PECO to perform the services, once again on very short notice.

Second, even if the number of customers for whom PECO must provide metering and meter reading eventually settles at a stabilized, lower level, PECO would still incur a cost per customer much higher than would currently be required. Most notably, in the case of meter reading, installation, and maintenance, PECO would still have to cover the same area, as default service customers could be scattered throughout the entire service territory. And, not only would the customers' identity and location change every month, the number of customers whose meters PECO would have to install, maintain, and read in a particular area could suddenly jump dramatically. Accordingly, to ensure timely and accurate meter reads and provision of complete billing data, PECO would have to maintain a relatively large group of meter technicians and readers in a number of locations dispersed around its service territory.

Of course, PECO would also have to have a correspondingly higher number of meters in inventory at any time, as it would have to replace an EGS' meter on very short notice whenever an EGS' customer returns to default service for one of the many reasons discussed above.

Therefore, as PECO would not avoid most metering and meter reading costs, using ***all*** of them as the basis for the credit for non-wires services that EGSs would receive under the Enron proposal is totally unjustified. Only a fraction of such costs should be used to design any credit for non-wires services.

Q. With regard to uncollectibles, please explain in more detail the reasons PECO would continue to incur these costs even if EGSs were to provide non-wires services.

A. PECO incurs uncollectibles expense to: (1) fund long-term special payment agreements required by Chapter 56; (2) fund the CAP, or Customer Assistance Program (i.e., the write offs of the difference between what CAP customers pay under the discounted CAP Rates and what they would otherwise have paid under the base rates); and (3) cover the cost associated with non-payment by customers without payment agreements, customers who violate the terms of payment agreements, and all other non-CAP customers. The amounts included in this last category are substantial because, due to the requirements of Chapter 56, it is very difficult to terminate service to residential customers. Under the Enron Tariff structure, PECO, ***not*** the EGSs, will ***still*** have these financial obligations. This is because EGSs will be able to jettison non-paying customers on five days notice, and are likely to avoid initially serving customers with poor credit histories.

In addition, regardless of the fact that Enron would be the purported provider-of-last resort, the MBC Services Agreement imposes on PECO all of the financial obligations associated with bad-paying default service customers, including those default service customers previously jettisoned by EGSs. Finally, as I have noted earlier in my testimony, Enron would require that all CAP Rate customers be served under the default service provisions of the Enron Tariff, meaning that there is no possibility that EGSs would incur any uncollectible accounts expense associated with such customers -- PECO will incur all such expense.

Thus, because PECO will continue to incur these uncollectible accounts expenses, they should not be used as a basis for a non-wires services credit.

Q. **With regard to billing and collection/customer service and information costs, please explain in more detail the reasons PECO would continue to incur them at levels far higher than Mr. Reising assumes would be required even if EGSs were to provide non-wires services.**

With regard to billing, under the Enron Plan, PECO would have to prepare and provide to EGSs bills containing the same level of detail as those PECO would have provided directly to customers. These bills to EGSs not only would contain this same level of detail, but also would cover the same number of customers. Accordingly, there is no basis for the assumption that as EGSs gain customers, PECO's billing costs would decrease proportionately. PECO's billing costs would probably remain the same, or perhaps even increase, as PECO would have to upgrade its billing and computer systems to replace direct customer billing with EGS billing.

With respect to collection, it is also clearly incorrect to assume that under the Enron Plan, as EGSs add customers, PECO would increasingly avoid the collection expense it currently incurs. Under the Enron Plan, when a customer fails to pay an EGS, the EGS may terminate the customer on five days notice with the probable result the customer will return to default service. As PECO is responsible under the MBC Services Agreement for collection expense associated with default service customers, PECO will almost certainly continue to incur these collection costs. Nor is there any guarantee that under the Enron Plan EGSs would pose no collection risk or cost to PECO. Rather, PECO probably would continue to incur substantial costs to pursue EGSs that do not pay their bills to PECO.

With regard to customer service and information costs, as is true with metering and meter reading, PECO would have to stand ready to provide these services, on short notice, to a considerable number of additional customers it does not serve regularly. PECO would have to have available a substantial workforce, and technical capability – i.e., phone lines, computer systems, etc. – to ensure its ability to handle a large volume of calls and service inquiries.

Notably, even under the Enron Plan, PECO would continue to maintain phone lines for reporting emergencies and thus would also have to maintain the capability to staff and operate those phone lines. No basis exists, therefore, for concluding that as EGSs assume some customer service responsibility, PECO would avoid an amount of cost in direct proportion to the number of customers obtaining such service from EGSs.

Q. With regard to the sales and lighting-related costs that Mr. Reising includes in his credit, please explain in more detail the reasons PECO would continue to incur them even if EGSs were to provide non-wires services.

A. With regard to sales expense, the Company expects to maintain the activities that cause these costs at current levels. These costs are not associated with the non-wires services that PECO would avoid if EGSs were allowed to provide non-wires services competitively. They include expenses associate with demand-side management and energy efficiency and audit programs, and certain of the costs of processing high bill complaints and otherwise complying with Chapter 56. Accordingly, they should not be included at all in the basis for the credit for non-wires services.

With regard to lighting-related services expense, why Mr. Reising includes these costs in his credit calculation is a mystery, for they are totally unrelated to the non-wires services that EGSs would provide under Enron's plan: metering, meter reading, billing, collection, and customer and information services. The costs

PECO incurs in connection with street lights are appropriately included in its street lighting rates, and would continue to be included in those rates under the Enron Plan. PECO would not avoid them if an EGS were to provide non-wires services, and therefore they should not be included in any credit for such services.

Q. **Mr. Sundermeir, you have explained how Mr. Reising has failed to recognize that PECO would not avoid all of the costs that it currently incurs for non-wires services if EGSs were to be allowed to perform them on a competitive basis. Did Mr. Reising, however, use correct cost figures from PECO's accounts as the starting point for his non-wires services credit?**

A. No, it appears he did not. With the assistance of persons under my supervision, I have reviewed PECO's cost of service study to identify the costs associated with the non-wires services EGSs would provide under the Enron Plan. In every instance, Mr. Reising has not correctly identified those costs. In fact, Mr. Reising's figure of more than $240 million is more than three times higher than the total cost to provide non-wires services.

Q. **What cost-of-service study did you review to identify the appropriate costs?**

A. I reviewed the cost-of-service study prepared by Mr. Robert A. Clemmer, which he submitted with his rebuttal testimony (Exhibit RAC-10, PECO Statement No. 12-R).

Q. Mr. Sundermeir, please explain how you identified the appropriate costs for each category of costs that should form the basis for a non-wires services credit, and present the results of your analysis.

A. The results of my analysis are presented in the attached Exhibit WFS-15. All of the data I report on that exhibit are taken from Exhibit RAC-10. For metering, I include the annual carrying costs on the dollars associated with net plant for meters (FERC account 370 for original cost plant less associated plant reserve). I have determined the annual carrying costs on net plant by taking the average system rate of return, which is 9.44% (after adjustment for other revenues), and increasing it for income taxes, for a total of 13.33%. To this, I have added the direct meter O&M costs (FERC accounts 586 and 597) and meter depreciation expense (account 940). For meter reading I used FERC account 902.

For billing and collections, I used FERC account 903 less costs that have been determined to be related to Chapter 56 activities. I excluded any amounts for Chapter 56 related activities for the same reason I believe that uncollectible accounts expense should not be included as part of the basis for a non-wires services credit. PECO will continue to be the only entity that incurs these costs, as it will be solely responsible for undertaking them and assuming the financial responsibilities associated with them. Analysis of the work centers whose responsibility it is to perform the necessary Chapter 56-related activities reveals that PECO incurred $22,182,000 for these activities in 1996, which is the test year used in PECO's cost allocation study.

For customer services and information, I added the expenses in FERC accounts 905 through 910, and, as I did for billing and collection, I deducted expenses associated with Chapter 56 related activities. Analysis reveals that PECO incurred $4,110,000 for these activities in 1996.

Q. **Mr. Sundermeir, based on the results of your analysis of the costs that could form the basis of a credit for non-wires services, have you designed non-wires services credits that would be appropriate were the Commission ever to require unbundling of these non-wires services?**

A. Yes, I have. Included in Exhibit WFS-15 are spreadsheets showing the development of a fixed credit for non-wires service for each rate class. These credits are based on the costs I have identified above. If non-wires services are unbundled, which I note again PECO does not believe is appropriate, any Commission-approved credits should not exceed the credits I have designed, as they are based on costs from PECO's cost-of-service study.

Q. **But won't use of these costs result in credits that are higher than they should be for the reasons you explained earlier in your testimony?**

A. Yes. Because PECO would not actually avoid many of these costs for the reasons I have described above, these credits are in fact higher than they really should be. Use of these credits, therefore, would, in fact, "strand" some PECO investment in equipment and under-recover ongoing non-wires expenses.

Q. Why then does PECO suggest use of these credits, assuming unbundling does occur, if the result would be additional stranded costs?

A. Because, for some categories of non-wires costs, ***at this time*** it is impossible for PECO to determine with precision the actual level of expense it would avoid if non-wires services were unbundled. Although for the reasons I articulated earlier it is clear that PECO would not avoid most of its current costs, and would not avoid an amount in direct proportion to the number of customers obtaining non-wires services from EGSs, I cannot precisely quantify these effects. Accordingly, if the Commission requires unbundling of non-wires services, I suggest that PECO be allowed to track these costs. Then, following expiration of the non-generation charges rate cap, PECO should be allowed to seek recovery of the actual stranded amount through an appropriate cost recovery mechanism.

Q. Mr. Sundermeir, the credits you have designed are fixed credits rather than energy based credits, which Mr. Reising proposes. Why do you propose fixed credits rather than energy-based credits?

A. The first reason is that an energy-based credit is inappropriate because the components of non-wires services are principally customer-related expenses that are not a function of demand or energy use. For Rate R, for example, the cost of a meter and meter reading are usually the same regardless of the amount of usage - - it costs the same amount to provide, maintain, and read a meter for a residential customer who uses no energy as it does for a residential customer who uses thousands of kilowatt-hours. Accordingly, these costs have been recovered traditionally through a fixed monthly customer charge or distribution charge.

Q. From a policy standpoint, why would it be a bad idea to provide a credit for non-wires services that is based on energy use?

A. It would be a bad idea because it would mean that EGSs providing non-wires services to relatively higher use customers would receive a credit that is far greater than it will actually cost them to provide the services. The greater the customer's usage, the greater the credit an EGS would receive, even though PECO will ***avoid*** no further cost and the EGS will ***incur*** no more cost as usage increases. This means that an EGS serving higher use customers will receive a windfall at PECO's expense.

Q. What other problems would use of an energy-based credit cause?

A. For the reasons I just described, it would cause EGSs that choose to provide non-wires services to "cherry-pick" higher use customers, as they will incur no additional cost to serve such customers but will receive a much greater credit. This could have at least two serious consequences. The first consequence is that EGSs will not offer non-wires services to lower use customers, and, in fact, will have no interest in serving such customers whose usage levels will not provide the EGSs with a credit that is at or above their cost to serve.

Q. With regard to this first consequence, can you explain in more detail why many residential customers would likely not have the opportunity to obtain non-wires services if Enron's proposed energy-based credit design were to be adopted?

A. Certainly. As shown in Exhibit WFS-15, it currently costs PECO to provide non-wires services to a Rate R customer about $3.59 per month per customer. An energy-based credit that would be the equivalent of this charge would be 0.54¢ per kWh ($57,108,000/[7,699,431 kWh + 2,816,467 kWh]). This means that an EGS would receive a credit equal to PECO's proposed fixed credit for a customer that uses 617 kilowatt-hours. If we assume that it will cost an EGS about as much as it will cost PECO to provide non-wires services, an EGS would receive a credit greater than its cost for all residential customers who use more than this "break-even" level. Many customers use less than 617 kilowatt-hours, and many of those are low income customers. It is to these customers that EGSs would likely not offer competitive non-wires services, meaning that Enron would deny to them something it has so strenuously argued would be of benefit to all customers.

Q. Would this problem be worse if Enron's proposed cost basis were used?

A. Yes. If Enron's higher cost basis were used, the break-even cost would be higher, meaning that far more customers would be considered by EGSs as lower use customers not worthy of their attention as providers of non-wires services.

Q. What is the second serious consequence that an energy-based credit pose?

A. It almost guarantees that when the non-generation charges rate cap expires, PECO would have to seek a rate increase even if the overall level of costs has not increased by that time. This is because the inevitable cherry-picking by EGSs will lead to PECO's under-recovery of costs it still incurred to provide non-wires services and to stand ready to provide them for default customers. PECO would have to provide to EGSs substantial credits far above PECO's avoided costs, as EGSs will serve mostly higher use customers, yet PECO would be unable to recoup this loss through giving lower credits to other customers -- EGSs will not serve those customers because they would lose money if they did.

Q. Mr. Sundermeir, do you have any final thoughts regarding the non-wires service credit?

A. Yes. If the Commission ever does require unbundling of these non-wires services, it is the customer and not the EGS that should receive the credit. Customers would then be able to comparison shop for non-wires services, just as they will be able to for energy under the Partial Settlement.

V. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

<u>Enron Tariff Provision</u>	<u>Problem/Error</u>
Omissions on first and second pages	Commission regulations require the "Notice" statement, and the "issued by" language, and also require a "change" page
Definition of "bad credit" (Page 8)	Enron eliminates application of this definition to all customers and restricts to only Default Service customers.
Definition of Electric Generation Supplier (EGS)	Permits "end-user" to function in role of EGS, yet fails to require that such end-user have PUC license
Definition of Meter Service Provider ("MSP")	Fails to state whether an MSP can perform meter reading, meter maintenance, billing, and other "non-wires" services
Definition of "Non-Wires Services" and Credit for "Non-Wires Services"	Enron provides no definition, and provides no basis for credit, yet these terms are crucial to Enron Tariff
Definition of "Open Access Tariff"	PECO no longer operates under this tariff; PECO operates under the PJM Open Access Tariff
Added Definition of "Service Extension"	This definition is internally inconsistent with that of service supply line; and in 6.3, apparently shifts to the customers the responsiblity to provide, own & maintain the service extension
Definition of "summary billing account"	Enron deletes this provision, leaving uncertainty regarding the continued availability of summary billing. Would PECO have to send an EGS a separate bill for the T&D service provided to each of the EGS' customers
Rule 1.4	Enron deletes this rule, yet PECO will still read many meters, and will therefore need the right to prorate charges
Rule 6.4	Revision results in internal contradiction, as PECO would still own transformers that are integrally part of the meter that PECO might

	not own under the Enron Tariff
Rule 7.3	Enron modifies language as mandated by Pa. Code §§57.81-83, and which cannot be changed, absent a change or waiver of those regulations
Rule 9.7	Enron eliminates a rule regarding fees for switching or transferring service that in a prior base rate case the PaPUC ordered PECO to include
Rule 12.3	Enron modifies language as mandated by Pa. Code §§57.52. Moreover, the applicability of their new definition of an "emergency energy situation" as covering "energy generators overall" is unclear
Rules 18.3 through 18.5	Rules use term "service connection," but Enron includes no definition of this term
Rule 21. 4	Precludes a consumer from requesting a billing investigation

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh (1)		Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling (4)	Supplement No. 10 Unbundled Pricing (5)	Revenue (6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 5.5790	$ 138,983,165
First 150 hrs use	3,730,248,598	$ 0.0303	$ 113,058,072
Next 150 hrs use	3,640,776,279	$ 0.0181	$ 65,933,986
Additional use	4,334,660,758	$ 0.0060	$ 26,191,984
	670,490,224		$ 344,167,208
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 511,832,096
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 3.0031	$ 74,812,877
First 150 hrs use	3,730,248,598	$ 0.0299	$ 111,514,504
Next 150 hrs use	3,640,776,279	$ 0.0233	$ 84,933,171
Additional use	4,334,660,758	$ 0.0168	$ 72,963,506
8. Total Sample			$ 856,056,154
9. Total PECO Charges			$ 511,832,096
10. Total Electric Generation			$ 344,224,058
11. Proforma Base Revenue			$ 856,056,154
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 1.35	$ 424,191
Electric Generation	314,340	$ 0.72	$ 226,493
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0294	$ 1,376,601
Electric Generation	46,820,419	0.0268	$ 1,257,048
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 886,444,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh (1)		Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling (4)	Supplement No. 10 Unbundled Pricing (5)	Revenue (6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 5.5791	$ 138,985,651
First 150 hrs use	3,730,248,598	$ 0.0303	$ 113,060,095
Next 150 hrs use	3,640,776,279	$ 0.0181	$ 65,935,166
Additional use	4,334,660,758	$ 0.0060	$ 26,192,453
	670,496,381		$ 344,173,365
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 511,838,253
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 3.7976	$ 94,604,475
First 150 hrs use	3,730,248,598	$ 0.0342	$ 127,614,295
Next 150 hrs use	3,640,776,279	$ 0.0259	$ 94,322,359
Additional use	4,334,660,758	$ 0.0177	$ 76,693,320
8. Total Sample			$ 905,072,702
9. Total PECO Charges			$ 511,838,253
10. Total Electric Generation			$ 393,234,449
11. Proforma Base Revenue			$ 905,072,702
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 1.33	$ 418,010
Electric Generation	314,340	$ 0.89	$ 279,825
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0294	$ 1,376,625
Electric Generation	46,820,419	0.0308	$ 1,440,325
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 935,691,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh		Supplement No. 10 Bundled Pricing	Revenue	Unbundled Components	Bills and kwh from unbundling	Supplement No. 10 Unbundled Pricing	Revenue
	(1)		(2)	(3)=(1)x(2)	.	(4)	(5)	(6)=(4)x(5)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827	1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
					2.Transmission Charge			
					Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
					First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
					Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
					Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
								$ 49,354,312
					3.Variable Distribution Charge			
					Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
					First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
					Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423	Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609				$ 109,825,282
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695	4.Competitive Transition Charge			
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705	Capacity Charge (kW)	24,911,867	$ 5.4680	$ 136,217,037
					First 150 hrs use	3,730,248,598	$ 0.0297	$ 110,807,921
	11,705,685,635	kWh			Next 150 hrs use	3,640,776,279	$ 0.0177	$ 64,621,728
					Additional use	4,334,660,758	$ 0.0059	$ 25,670,695
						663,640,397		$ 337,317,381
6. Night Service Rider					5. Night Service Rider			
Customer Charge	3,840		$ 11.21	$ 43,046	Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421	Demand Charge	525,737	$ 0.91	$ 478,421
					6. PECO Charges-Sample			$ 504,982,269
					7. Electric Generation			
					Capacity Charge (kW)	24,911,867	$ 4.3854	$ 109,249,460
					First 150 hrs use	3,730,248,598	$ 0.0374	$ 139,527,492
					Next 150 hrs use	3,640,776,279	$ 0.0278	$ 101,269,979
					Additional use	4,334,660,758	$ 0.0183	$ 79,453,231
7. Total				$ 954,610,726	8. Total Sample			$ 934,482,430
					9. Total PECO Charges			$ 504,982,269
					10. Total Electric Generation			$ 429,500,161
Rate HT								
8. Proforma Base Revenue				$ 954,089,259	11. Proforma Base Revenue			$ 934,482,430
9. HVD >66kv				$ (180)	12. HVD >66kv			$ (180)
10. HVD 66kv				$ (8,983)	13. HVD 66kv			$ (8,983)
11. HVD 33kv				$ (611,242)	14. HVD 33kv			$ (611,242)
12. Aux Serv Rider					15. Aux Serv Rider			
Firm kW	314,340		$ 3.00	$ 943,020	Firm kW			
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039	Transmission	314,340	$ 0.18	$ 56,581
Interr. kWh	35,721,342		$ 0.0274	$ 978,765	Distribution	314,340	$ 0.45	$ 141,453
					Competitive Transition Charge	314,340	$ 1.29	$ 406,416
					Electric Generation	314,340	$ 1.02	$ 319,709
					Firm kWh			
					Transmission	46,820,419	0.0039	$ 180,259
					Distribution	46,820,419	0.0104	$ 485,528
					Competitive Transition Charge	46,820,419	0.0288	$ 1,349,203
					Electric Generation	46,820,419	0.0337	$ 1,577,729
					Interr. kWh	35,721,342	0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)	16. Curtailment Rider			$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110	17. NSR-Supplemental Energy			$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000	18. Adjusted Base Revenue			$ 965,239,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh (1)		Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling (4)	Supplement No. 10 Unbundled Pricing (5)	Revenue (6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 5.3092	$ 132,261,159
First 150 hrs use	3,730,248,598	$ 0.0288	$ 107,589,949
Next 150 hrs use	3,640,776,279	$ 0.0172	$ 62,745,048
Additional use	4,334,660,758	$ 0.0058	$ 24,925,193
	653,844,365		$ 327,521,349
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 495,186,237
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 4.8621	$ 121,123,053
First 150 hrs use	3,730,248,598	$ 0.0400	$ 149,186,255
Next 150 hrs use	3,640,776,279	$ 0.0294	$ 106,902,843
Additional use	4,334,660,758	$ 0.0188	$ 81,690,861
8. Total Sample			$ 954,089,249
9. Total PECO Charges			$ 495,186,237
10. Total Electric Generation			$ 458,903,012
11. Proforma Base Revenue			$ 954,089,249
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 1.25	$ 392,631
Electric Generation	314,340	$ 1.12	$ 352,355
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0280	$ 1,310,020
Electric Generation	46,820,419	0.0361	$ 1,690,232
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 984,938,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh		Supplement No. 10 Bundled Pricing	Revenue
	(1)		(2)	(3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling	Supplement No. 10 Unbundled Pricing	Revenue
	(4)	(5)	(6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 5.1497	$ 128,288,250
First 150 hrs use	3,730,248,598	$ 0.0280	$ 104,358,123
Next 150 hrs use	3,640,776,279	$ 0.0167	$ 60,860,290
Additional use	4,334,660,758	$ 0.0056	$ 24,176,481
	644,006,159		$ 317,683,143
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 485,348,031
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 5.0215	$ 125,095,962
First 150 hrs use	3,730,248,598	$ 0.0409	$ 152,418,081
Next 150 hrs use	3,640,776,279	$ 0.0299	$ 108,787,602
Additional use	4,334,660,758	$ 0.0190	$ 82,439,573
8. Total Sample			$ 954,089,249
9. Total PECO Charges			$ 485,348,031
10. Total Electric Generation			$ 468,741,218
11. Proforma Base Revenue			$ 954,089,249
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 1.21	$ 380,837
Electric Generation	314,340	$ 1.16	$ 364,149
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0280	$ 1,310,020
Electric Generation	46,820,419	0.0361	$ 1,690,232
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 984,938,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh (1)		Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling (4)	Supplement No. 10 Unbundled Pricing (5)	Revenue (6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 4.9902	$ 124,315,744
First 150 hrs use	3,730,248,598	$ 0.0271	$ 101,126,625
Next 150 hrs use	3,640,776,279	$ 0.0162	$ 58,975,722
Additional use	4,334,660,758	$ 0.0054	$ 23,427,845
	634,168,952		$ 307,845,936
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 475,510,824
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 5.1810	$ 129,068,467
First 150 hrs use	3,730,248,598	$ 0.0417	$ 155,649,579
Next 150 hrs use	3,640,776,279	$ 0.0304	$ 110,672,169
Additional use	4,334,660,758	$ 0.0192	$ 83,188,209
8. Total Sample			$ 954,089,249
9. Total PECO Charges			$ 475,510,824
10. Total Electric Generation			$ 478,578,425
11. Proforma Base Revenue			$ 954,089,249
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 1.17	$ 369,044
Electric Generation	314,340	$ 1.20	$ 375,942
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0280	$ 1,310,020
Electric Generation	46,820,419	0.0361	$ 1,690,232
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 984,938,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh (1)		Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling (4)	Supplement No. 10 Unbundled Pricing (5)	Revenue (6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 4.6739	$ 116,435,170
First 150 hrs use	3,730,248,598	$ 0.0254	$ 94,716,046
Next 150 hrs use	3,640,776,279	$ 0.0152	$ 55,237,157
Additional use	4,334,660,758	$ 0.0051	$ 21,942,716
	614,654,105		$ 288,331,089
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 455,995,977
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 6.2919	$ 156,743,126
First 150 hrs use	3,730,248,598	$ 0.0478	$ 178,161,972
Next 150 hrs use	3,640,776,279	$ 0.0340	$ 123,801,101
Additional use	4,334,660,758	$ 0.0204	$ 88,403,620
8. Total Sample			$ 1,003,105,796
9. Total PECO Charges			$ 455,995,977
10. Total Electric Generation			$ 547,109,819
11. Proforma Base Revenue			$ 1,003,105,796
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 1.09	$ 341,644
Electric Generation	314,340	$ 1.43	$ 450,493
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0246	$ 1,153,267
Electric Generation	46,820,419	0.0434	$ 2,030,287
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 1,034,185,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh (1)		Supplement No. 10 Bundled Pricing (2)	Revenue (3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling (4)	Supplement No. 10 Unbundled Pricing (5)	Revenue (6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 4.5151	$ 112,479,799
First 150 hrs use	3,730,248,598	$ 0.0245	$ 91,498,486
Next 150 hrs use	3,640,776,279	$ 0.0147	$ 53,360,718
Additional use	4,334,660,758	$ 0.0049	$ 21,197,309
	604,859,329		$ 278,536,313
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 446,201,201
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 7.2452	$ 180,492,582
First 150 hrs use	3,730,248,598	$ 0.0529	$ 197,481,345
Next 150 hrs use	3,640,776,279	$ 0.0371	$ 135,067,907
Additional use	4,334,660,758	$ 0.0214	$ 92,879,308
8. Total Sample			$ 1,052,122,343
9. Total PECO Charges			$ 446,201,201
10. Total Electric Generation			$ 605,921,142
11. Proforma Base Revenue			$ 1,052,122,343
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 1.04	$ 326,597
Electric Generation	314,340	$ 1.63	$ 512,691
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0238	$ 1,114,090
Electric Generation	46,820,419	0.0481	$ 2,252,766
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 1,083,432,000

PECO Energy Company-Electric Operations
Rate HT
Calculation of Revenue - Supp No. 10 Bundled and Unbundled
12 months ended 12/31/96 - Universe Billing Determinants and Revenues

12 Month Data	Bills and kwh		Supplement No. 10 Bundled Pricing	Revenue
	(1)		(2)	(3)=(1)x(2)
1. Customer Charge	27,762	bills	$ 286.86	$ 7,963,827
2. All KW	24,911,867	kW	$ 12.76	$ 317,875,423
3. Kwh-First 150 Hrs	3,730,248,598		$ 0.0829	$ 309,237,609
4. Kwh-Next 150 Hrs	3,640,776,279		$ 0.0550	$ 200,242,695
5. Kwh-Addl Use	4,334,660,758		$ 0.0274	$ 118,769,705
	11,705,685,635	kWh		
6. Night Service Rider				
Customer Charge	3,840		$ 11.21	$ 43,046
Demand Charge	525,737		$ 0.91	$ 478,421
7. Total				$ 954,610,726
Rate HT				
8. Proforma Base Revenue				$ 954,089,259
9. HVD >66kv				$ (180)
10. HVD 66kv				$ (8,983)
11. HVD 33kv				$ (611,242)
12. Aux Serv Rider				
Firm kW	314,340		$ 3.00	$ 943,020
Firm kWh	46,820,419		$ 0.0783	$ 3,666,039
Interr. kWh	35,721,342		$ 0.0274	$ 978,765
13. Curtailment Rider				$ (286,778)
14. NSR-Supplemental Energy				$ 26,168,110
15. Adjusted Base Revenue				$ 984,938,000

Unbundled Components	Bills and kwh from unbundling	Supplement No. 10 Unbundled Pricing	Revenue
	(4)	(5)	(6)=(4)x(5)
1.Fixed Distribution Charge	27,762	$ 286.86	$ 7,963,827
2.Transmission Charge			
Capacity Charge (kW)	24,911,867	$ 0.8000	$ 19,930,482
First 150 hrs use	3,730,248,598	$ 0.0043	$ 16,212,769
Next 150 hrs use	3,640,776,279	$ 0.0026	$ 9,455,074
Additional use	4,334,660,758	$ 0.0009	$ 3,755,986
			$ 49,354,312
3.Variable Distribution Charge			
Capacity Charge (kW)	24,911,867	$ 1.7803	$ 44,350,144
First 150 hrs use	3,730,248,598	$ 0.0097	$ 36,077,332
Next 150 hrs use	3,640,776,279	$ 0.0058	$ 21,039,827
Additional use	4,334,660,758	$ 0.0019	$ 8,357,978
			$ 109,825,282
4.Competitive Transition Charge			
Capacity Charge (kW)	24,911,867	$ 4.1974	$ 104,565,793
First 150 hrs use	3,730,248,598	$ 0.0228	$ 85,060,712
Next 150 hrs use	3,640,776,279	$ 0.0136	$ 49,606,293
Additional use	4,334,660,758	$ 0.0045	$ 19,705,880
	585,261,695		$ 258,938,679
5. Night Service Rider			
Fixed Distribution Charge	3,840	$ 11.21	$ 43,046
Demand Charge	525,737	$ 0.91	$ 478,421
6. PECO Charges-Sample			$ 426,603,567
7. Electric Generation			
Capacity Charge (kW)	24,911,867	$ 7.5629	$ 188,406,587
First 150 hrs use	3,730,248,598	$ 0.0547	$ 203,919,119
Next 150 hrs use	3,640,776,279	$ 0.0381	$ 138,822,332
Additional use	4,334,660,758	$ 0.0218	$ 94,370,737
8. Total Sample			$ 1,052,122,343
9. Total PECO Charges			$ 426,603,567
10. Total Electric Generation			$ 625,518,776
11. Proforma Base Revenue			$ 1,052,122,343
12. HVD >66kv			$ (180)
13. HVD 66kv			$ (8,983)
14. HVD 33kv			$ (611,242)
15. Aux Serv Rider			
Firm kW			
Transmission	314,340	$ 0.18	$ 56,581
Distribution	314,340	$ 0.45	$ 141,453
Competitive Transition Charge	314,340	$ 0.97	$ 303,618
Electric Generation	314,340	$ 1.70	$ 535,670
Firm kWh			
Transmission	46,820,419	0.0039	$ 180,259
Distribution	46,820,419	0.0104	$ 485,528
Competitive Transition Charge	46,820,419	0.0221	$ 1,035,703
Electric Generation	46,820,419	0.0498	$ 2,331,153
Interr. kWh	35,721,342	0.0274	$ 978,765
16. Curtailment Rider			$ (286,778)
17. NSR-Supplemental Energy			$ 26,168,110
18. Adjusted Base Revenue			$ 1,083,432,000

PECO ENERGY COMPANY

DEVELOPMENT OF NON-WIRES SERVICES FIXED MONTHLY CREDIT

(All page references apply to PECO Exhibit RAC-10, All dollars in thousands except for line [42])

		TOTAL	HT	EP	PD	GS	RH	R	OP
	Meters								
	Original Cost								
1.	370 - Meters & Installations (Page 31 of 83)	$ 192,889	$ 3,645	$ 125	$ 10,525	$ 26,907	$ 15,126	$ 114,522	$ 22,019
2.									
3.	less: Accumulated Depreciation								
4.	370 - Meters & Installations (Page 35 of 83)	$ (48,927)	$ (2,977)	$ (83)	$ (2,851)	$ (2,460)	$ (3,884)	$ (28,377)	$ (8,283)
5.									
6.	Net Plant ([1] + [4])	$ 143,962	$ 668	$ 42	$ 7,674	$ 24,447	$ 11,242	$ 86,146	$ 13,736
7.									
8.	Pre-tax Return ([6] x 13.33%) {See Note 1}	$ 19,190	$ 89	$ 6	$ 1,023	$ 3,259	$ 1,499	$ 11,483	$ 1,831
9.									
10.									
11.	Meters								
12.	586 - Meter Expenses (Page 15 of 83)	$ 112	$ 2	$ 0	$ 6	$ 16	$ 10	$ 72	$ 6
13.	597 - Maintenance of Meters (Page 17 of 83)	$ 90	$ 2	$ 0	$ 5	$ 13	$ 7	$ 53	$ 10
14.	370 - Meters & Install.(Depreciation) (Page 23 of 83)	$ 6,696	$ 407	$ 11	$ 390	$ 337	$ 532	$ 3,884	$ 1,134
15.	Pre-tax Return ([8])	$ 19,190	$ 89	$ 6	$ 1,023	$ 3,259	$ 1,499	$ 11,483	$ 1,831
16.	Total - Meters ([12] + [13] + [14] + [15])	$ 26,088	$ 500	$ 17	$ 1,424	$ 3,624	$ 2,047	$ 15,493	$ 2,981
17.									
18.	Meter Reading								
19.	902 - Meter Reading Expense (Page 19 of 83)	$ 8,299	$ 349	$ 8	$ 87	$ 729	$ 775	$ 5,856	$ 495
20.									
21.	Billing & Collection								
22.	903 - Customer Records & Contracts (Page 19 of 83)	$ 41,171	$ 56	$ 0	$ 26	$ 3,811	$ 4,052	$ 30,617	$ 2,586
23.	Credit for Chapter 56 Costs {See Note 2}	$ (22,182)	$ (30)	$ (0)	$ (14)	$ (2,053)	$ (2,183)	$ (16,495)	$ (1,393)
24.	Total Billing & Collection ([22] + [23])	$ 18,989	$ 26	$ 0	$ 12	$ 1,758	$ 1,869	$ 14,121	$ 1,193
25.									
26.	Customer Services & Information								
27.	905 - Misc. Customer Accounts Expense (Page 19 of 83)	$ 972	$ 8	$ 0	$ 2	$ 89	$ 95	$ 717	$ 61
28.	907 - Supervision (Page 19 of 83)	$ 28	$ 4	$ 0	$ 0	$ 5	$ 3	$ 16	$ 0
29.	908 - Customer Assistance Expense (Page 19 of 83)	$ 7,221	$ 1,056	$ 51	$ 115	$ 1,183	$ 692	$ 4,053	$ 28
30.	909 - Informational & Instruct. Advertising (Page 19 of 83)	$ 1,917	$ 280	$ 14	$ 31	$ 314	$ 184	$ 1,076	$ 7
31.	910 - Misc. Cust. Service & Information (Page 19 of 83)	$ 15,678	$ 2,293	$ 111	$ 250	$ 2,568	$ 1,502	$ 8,800	$ 61
32.	Credit for Chapter 56 Costs {See Note 2}	$ (4,110)	$ (601)	$ (29)	$ (66)	$ (673)	$ (394)	$ (2,307)	$ (16)
33.	Total - Cust. Serv. & Info. ([27]+[28]+[29]+[30]+[31]+[32])	$ 21,706	$ 3,040	$ 147	$ 333	$ 3,486	$ 2,082	$ 12,354	$ 141
34.									
35.	Total Non-Wire Services Costs ([16]+[19]+[24]+[33])	$ 75,082	$ 3,914	$ 172	$ 1,856	$ 9,597	$ 6,772	$ 47,823	$ 4,809
36.	Total Non-Wire Services Costs incl. PA GRT ([35] / 0.956)	$ 78,538	$ 4,095	$ 180	$ 1,942	$ 10,038	$ 7,084	$ 50,024	$ 5,031
37.							$57,108		
38.	Customers								
39.	Allocation Schedules D8 & D15 (Page 45 of 83)		2,252	39	1,047	145,604	154,794	1,169,654	98,781
40.							1,324,448		
41.									
42.	**Monthly Charge ([36] / [39] / 12 * 1000)**		**$151.51**	**$385.50**	**$154.54**	**See Note 3**	**$3.59**		**$4.24**

NOTES:

(1) Pre-tax Return of 13.33% equals (Rate of Return After Other Revenue Adjustment) 9.44% from Page 5 of 83 of Exhibit RAC-10 less 1.64% for "Tax Savings on Long-Term Debt" (PECO Exhibit JFBr-1 - Schedule 1 - Updated) then divided by 1 minus the effective tax rate of 41.494%.

(2) Includes costs for terminations, 72 hour notice, 10 day notice, CAP administration, LIURP, etc.

(3) Rate GS Non-Wire Services Credits are: (1) $3.19 for single-phase w/o demand measurement, (2) $4.17 for single-phase w/ demand measurement and (3) $11.29 for poly-phase customers.

PECO ENERGY COMPANY

DEVELOPMENT OF NON-WIRES SERVICES FIXED MONTHLY CREDIT

(All page references apply to PECO Exhibit RAC-10. All dollars in thousands except for line [42])

Line	Meters	SLP	SLS	SLE	OTHER
	Original Cost				
1.	370 - Meters & Installations (Page 31 of 83)	$ 0	$ 0	$ 0	$ 0
2.					
3.	less: Accumulated Depreciation				
4.	370 - Meters & Installations (Page 35 of 83)	$ (0)	$ (0)	$ (0)	$ (0)
5.					
6.	Net Plant ([1] + [4])	$ (0)	$ (0)	$ (0)	$ (0)
7.					
8.	Pre-tax Return ([6] x 13.33%) {See Note 1}	$ (0)	$ (0)	$ (0)	$ (0)
9.					
10.					
11.	Meters				
12.	586 - Meter Expenses (Page 15 of 83)	$ 0	$ 0	$ 0	$ 0
13.	597 - Maintenance of Meters (Page 17 of 83)	$ 0	$ 0	$ 0	$ 0
14.	370 - Meters & Install.(Depreciation) (Page 23 of 83)	$ 0	$ 0	$ 0	$ 0
15.	Pre-tax Return ([8])	$ (0)	$ (0)	$ (0)	$ (0)
16.	Total - Meters ([12] + [13] + [14] + [15])	$ 0	$ 0	$ 0	$ 0
17.					
18.	Meter Reading				
19.	902 - Meter Reading Expense (Page.19.of 83)	$ -	$ -	$ -	$ -
20.					
21.	Billing & Collection				
22.	903 - Customer Records & Contracts (Page 19 of 83)	$ 0	$ 11	$ 8	$ 5
23.	Credit for Chapter 56 Costs {See Note 2}	$ (0)	$ (6)	$ (4)	$ (3)
24.	Total Billing & Collection ([22] + [23])	$ 0	$ 5	$ 4	$ 2
25.					
26.	Customer Services & Information				
27.	905 - Misc. Customer Accounts Expense (Page 19 of 83)	$ 0	$ 0	$ 0	$ 0
28.	907 - Supervision (Page 19 of 83)	$ 0	$ 0	$ 0	$ 0
29.	908 - Customer Assistance Expense (Page 19 of 83)	$ 15	$ 6	$ 10	$ 5
30.	909 - Informational & Instruct. Advertising (Page 19 of 83)	$ 4	$ 1	$ 3	$ 1
31.	910 - Misc. Cust. Service & Information (Page 19 of 83)	$ 32	$ 12	$ 22	$ 12
32.	Credit for Chapter 56 Costs {See Note 2}	$ (8)	$ (3)	$ (6)	$ (3)
33.	Total - Cust. Serv. & Info. ([27]+[28]+[29]+[30]+[31]+[32])	$ 43	$ 16	$ 30	$ 16
34.					
35.	Total Non-Wire Services Costs ([16]+[19]+[24]+[33])	$ 43	$ 21	$ 33	$ 18
36.	Total Non-Wire Services Costs incl. PA GRT ([35] / 0.956)	$ 45	$ 22	$ 35	$ 19
37.					
38.	Customers				
39.	Allocation Schedules D8 & D15 (Page 45 of 83)	98,513	21,130	70,775	437
40.					
41.					
42.	**Monthly Charge ([36] / [39] / 12 * 1000)**	**$0.04**	**$0.09**	**$0.04**	**$3.62**

NOTES:

(1) Pre-tax Return of 13.33% equals "Rate of Return After Other Revenue Adjustment" 9.44% from Page 5 of 83 of Exhibit RAC-10 less 1.64% for "Tax Savings on Long-Term Debt" (PECO Exhibit JFBr-1 - Schedule 1 - Updated) then divided by 1 minus the effective tax rate of 41.494%.

(2) Includes costs for terminations, 72 hour notice, 10 day notice, CAP administration, LIURP, etc.

(3) Rate GS Non-Wire Services Credits are: (1) $3.19 for single-phase w/o demand measurement, (2) $4.17 for single-phase w/ demand measurement and (3) $11.29 for poly-phase customers.

R-00973953, R00973953 C0001, C0007, etal

PECO STATEMENT NO. 21-E

Phila 11/17/97
E.H.

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**

DOCUMENT
FOLDER

TESTIMONY

OF

DAVID J. PRATZON

REGARDING THE ENRON CHOICE PLAN

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**Regarding The Power Purchase Agreement,
Reliability and Safety and Procedures to Ensure Direct Access**

November 7, 1997

DOCKETED
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TABLE OF CONTENTS

TESTIMONY OF DAVID J. PRATZON

I. INTRODUCTION

Q. Please state your name and address.

A. David J. Pratzon, PECO Energy Company ("PECO"), 2301 Market Street, Philadelphia, PA 19103.

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

A. I am currently an Interconnection Representative for PECO.

Q. Please briefly describe the scope of your responsibilities as an Interconnection Representative.

A. My duties and responsibilities include the following:

- participation in the development and review of PECO's wholesale tariffs, rate schedules and associated FERC filing packages;
- review of PECO bulk power contracts for consistency with Pennsylvania-New Jersey-Maryland Interconnection ("PJM") operations and rules;
- participation in the development of PECO philosophy for restructuring of the PJM power pool, and articulation of PECO's position to others;
- review of FERC policies as well as filings and orders of other pools, ISOs, utilities and power marketers for direct or precedential impact on PECO;

- participation in the design of PECO's supplier administration process for the implementation of retail access, and presentation of PECO's plans to other stakeholder groups.

Q. Have you previously testified in this proceeding?

A. Yes. I submitted rebuttal testimony (PECO St. 21-R) that addressed transmission and PJM-related issues associated with PECO's Restructuring Plan. In addition, I have submitted testimony in PECO's retail access pilot program proceeding at PUC Docket No. P-00971170.

Q. What is the purpose of your testimony?

A. I respond to Enron Energy Services Power, Inc.'s ("Enron") testimony and filings in support of its so-called "Choice Plan" (hereinafter, the "Enron Plan") as such testimony and filings concern the Firm Energy & Capacity Purchase and Sale Agreement ("Power Purchase Agreement or PPA") submitted by Enron. In particular, my testimony responds to Enron witnesses Steven J. Kean, Douglas R. Bohi and Kenneth J. Slater. In addition, I address the adequacy of the Enron Plan in articulating the processes necessary to ensure retail consumers' direct access to Electric Generation Suppliers.

Q. Please briefly summarize your testimony.

A. My testimony on the Power Purchase Agreement can be summarized as follows:

- Under the Power Purchase Agreement Enron would be performing the functions of a Provider of Last Resort in name only; PECO would be performing such functions in fact and substance.
- The Power Purchase Agreement would add no value, but rather would transfer value from PECO to Enron. In particular, it would fail to compensate PECO adequately for the energy

and capacity and other services provided under the PPA, and provides no compensation to PECO for the call contract rights it would give to Enron.

- The terms and conditions of the Power Purchase Agreement are so one-sided, oppressive and confiscatory that such an agreement would never arise through freely negotiated dealings between parties of equal bargaining position, and no reasonably prudent utility manager would agree to such terms and conditions.
- The Power Purchase Agreement results in disparate treatment of default service customers because it would penalize certain default service customers with higher prices.
- The Power Purchase Agreement shifts all risks to PECO. Thus, the PPA as drafted by Enron is a totally risk-free proposition for Enron, while providing Enron with a profit opportunity. This is a mismatch in the allocation of risks and rewards, and would not occur in a competitively negotiated bilateral agreement.
- Under the Power Purchase Agreement, Enron would be able to escape accountability to Pennsylvania default service customers, the Commission and other regulatory bodies.
- The Power Purchase Agreement is anti-competitive, because it would prevent PECO from marketing its energy and capacity in competition with Enron and would make it unavailable to Enron's competitors.

Further, I will testify that the Enron Plan would, for a variety of reasons, undermine reliability and safety of providing electric service to customers in PECO's service territory.

Finally, my testimony regarding procedures to ensure direct access is that Enron has failed to provide a clear, complete and adequate discussion of all of the processes necessary to ensure that retail consumers and EGSs would have access to each other under the Enron Plan.

II. THE POWER PURCHASE AGREEMENT

A. Overview of the Agreement

Q. Please generally describe the Power Purchase Agreement that was filed as part of the Enron Plan?

A. Enron has filed what it refers to as a "Firm Energy & Capacity Purchase and Sale Agreement." Through this agreement, which I shall refer to interchangeably as either the "Power Purchase Agreement" or "PPA," Enron contemplates that Enron would buy from PECO, and PECO would sell to Enron, energy and capacity under the terms and conditions set forth in the PPA.

Q. How does the Power Purchase Agreement proposed by Enron fit with its proposal to become the Provider of Last Resort in PECO's service territory?

A. Based on my reading of the Enron testimony and the terms and conditions of the PPA, Enron is submitting the PPA as the vehicle through which it would acquire some or all of the power services necessary to supply energy to default service customers in PECO's service territory.

Q. Enron's witness, Kenneth J. Slater, has likened the PPA to an all requirements contract (Enron St. No. 4 at 8-9). Is that accurate?

A. No. As detailed later on in my testimony, Enron has not proposed a traditional type of requirements contract where the buyer commits to buying all of its needs from the seller and the requirements are reasonably predictable. Rather, under the Power Purchase Agreement, Enron's "requirements" would be in a constant state of flux. One obvious cause of this fluctuation is the shifting of load to and from EGSs. The other and more significant cause is the creation of two classes of default service customers and Enron's retention of an option – but not a requirement -- to buy power from PECO for one of those classes.

Q. Is the scope of the Power Purchase Agreement limited to the purchase of energy and capacity?

A. No, it goes well beyond that. The PPA is really several contracts rolled into one: a contract for the sale of energy and capacity, a call contract on energy and capacity, and a contract for competitively available services such as energy procurement and energy scheduling.

B. FERC Jurisdiction Over Power Purchase Agreement

Q. Is the sale of energy and capacity contemplated by the Power Purchase Agreement a wholesale or retail transaction?

A. It would be a wholesale transaction.

Q. Please explain what makes it a wholesale transaction.

A. Under the PPA, Enron would take title to the power at the point of delivery to the end-use consumer, prior to the actual consumption by the consumer. <u>See</u> PPA at § 6.3 at 5. Thus the sale of energy and capacity to Enron would be a sale of energy for resale.

Q. What significance is there to the wholesale status of the energy and capacity purchase under the Power Purchase Agreement?

A. The significance is that such transactions are subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. Does the FERC regulate PECO's wholesale sales of energy and capacity?

A. Yes. PECO's wholesale sales of energy and capacity are covered by PECO's FERC Electric Tariff - Volume No. 1 on file with the FERC. PECO also has on file with the FERC contracts for long-terms sales of energy and capacity.

C. <u>Default Service Customers</u>

Q. Who are the default service customers that Enron proposes to serve as the Provider of Last Resort?

A. Collectively, the default service customers to be served by Enron under its Plan are those customers who are not being served by an EGS. The PPA actually recognizes two categories of such customers: Transitional Default Service Customers" and "Standard Default Service Customers".

Q. Could you explain the difference between the Standard Default Service Customers and the Transitional Default Service Customers?

A. Under the PPA proposed by Enron, "Transitional Default Service Customers" mean customers in PECO's service territory who either (1) never chose an EGs or (2) executes a one-year energy services contract upon "returning" to the PLR from Enron. On the other hand, "Standard Default Service Customers" are customers in PECO's service territory who exercised their retail choice options but returned to the default energy provider either voluntarily or involuntarily.

Q. What is your understanding as to how a customers who exercised its choice could voluntarily return to default service?

A. The most readily apparent circumstance is that the customer, for whatever reasons, either was dissatisfied with the services provided by the Electric Generation Supplier it chose or decided that it simply preferred the service it had been receiving as a default service customer.

Q. What is your understanding as to how a customer who exercised its choice could be involuntarily returned to default service?

A. The most likely scenario is that the customer is terminated by the EGS for failure to pay its bills. Other scenarios include the supplier's bankruptcy or loss of its Electric Generation Supplier license.

Q. Is there any disparity in the way in which the two classes of default service customers are treated under the Enron Plan?

A. Yes. As explained below, Transitional Default Service Customers are penalized during the early years of the Enron Plan by being forced to pay above-market prices for energy and capacity. However, to fully understand how this happens you first need to understand the nature of the supply requirements that PECO must satisfy under the Power Purchase Agreement.

D. Enron's "Requirements"

Q. What requirements of Enron does the Power Purchase Agreement cover?

A. The Power Purchase Agreement covers "All Requirements" of Enron from September 1, 1998 through December 31, 2008 in supplying energy and capacity to default service customers.

Q. How does the Power Purchase Agreement define "All Requirements"?

A. "All Requirements" consist of both "Mandatory Requirements" and "Optional Requirements." Enron's "Mandatory Requirements" are its requirements for serving the Transitional Default Service Customers. See PPA at 2. Enron's "Optional Requirements" are its requirements for serving the Standard Default Service Customers. Id. Moreover, the requirements for each category of customers cover not just energy and capacity, but also "without limitation, all ancillary and other services required to transmit, distribute and deliver such energy to such customers . . .." Id.

Q. What is the significance of there being two categories of "requirements" that Enron must satisfy in serving default service customers in PECO's service territory?

A. The significance is that Enron, at its option, can purchase the energy and capacity it requires to serve Standard Default Service Customers from either the marketplace or PECO. On the other hand, Enron can only buy the energy and capacity required to serve Transitional Default Service Customers from PECO.

E. Disparate Treatment of Default Service Consumers

Q. How does Enron's differing obligations regarding default service customers affect those customers?

A. It is likely to have a significant adverse impact on Transitional Default Service Customers during the early years of the Enron Plan. This occurs because those customers would be paying an above-market price for energy and capacity. By contrast, because Enron has the option of buying energy and capacity from the market to serve Standard Default Service Customers, those customers may be able to obtain the same default service at a lower price.

Q. In your view, is the disparate treatment of Transitional Default Service Customers a cause for concern?

A. Yes. The pricing structure under the Enron Plan results in an unfair penalty to such customers.

Q. Could even Standard Default Service Customers end up paying above market prices for energy and capacity during the early years of the Enron Plan?

A. Yes. One could contemplate a scenario in which Enron, for whatever reason, might squander the difference between the generation credit and the true market price of energy and capacity. Enron has said that it has no desire to profit from default service customers but would simply pass through its costs to such customers. (See Enron St. No. 1 at 20). As such, Enron may have little incentive to minimize such costs to such customers. Further, to the extent there are no affiliate abuse protections, Enron and EPMI as part of the same "Enron Corp. family" (see Enron St. No. 1 at 23) have a clear economic incentive to have Enron buy energy and capacity from EPMI at a price just below the generation credit and in turn "pass on" those costs to the Standard Default Service Customers. Thus, all default service customers could end up being overcharged for energy and capacity in the early years of the Enron Plan.

Q. Are there other features of the Power Purchase Agreement that may have an adverse impact on default service customers?

A. Yes. Article 9 says that in the event of a default by PECO on its delivery obligations, Enron can collect all monies directly from Default Service customers. It further states that in such event, "nothing [in the PPA] shall restrict Buyer's rights with respect to charges to Default Service Customers pursuant to the Choice Plan and the Distribution Tariff." PPA § 9.3 at 8-9. I read this to mean that Enron would be free to charge default service customers whatever it wants if PECO defaults on its obligation to deliver energy and capacity under the PPA.

Q. What opportunities are there for a default under the Power Purchase Agreement?

A. There are numerous circumstances in which a default could occur under the PPA. For instance a breach of any of the warranties constitutes a defaulting event . In one of the warranties, PECO must represent and warrant that it either has the capacity and energy on hand or has access to such energy and capacity in the marketplace which would allow it to fully satisfy its delivery obligations. See PPA § 7.3. But one could contemplate a scenario in which PECO, due to no fault of its own, does not have such access. That scenario could be a system power emergency or a transmission problem. Even if such a situation were only temporary, it would appear that Enron could declare a default and terminate the contract, freeing it to charge default customers whatever it wants.

F. Contract Price

Q. What is the contract price payable to PECO under the Power Purchase Agreement?

A. The PPA contains two "contract prices," one for Enron's Mandatory Requirements and another for its Optional Requirements.

Q. What is the contract price for Enron's Mandatory Requirements?

A. The contract price is equal to the aggregate of a fixed price for a particular type of service – as predetermined by Enron and set forth in the price list attached to the PPA – multiplied by the quantity of that service, plus transmission and distribution costs. See PPA § 5.1 at 4.

Q. What is the contract price for Enron's Optional Requirements?

A. The contract price is stated in the price list attached to the PPA as being "[a] fully compensatory price based on a market index to be determined by default service provider."

Q. What do you understand that statement to mean?

A. I understand it to mean that Enron would have complete discretion as to the price it would pay us for energy and capacity delivered as part of its Optional Requirements. In essence, it is Enron as the buyer that gets to set the price of the power sold – not PECO, the seller of the power.

Q. Would the contract price stated in the Power Purchase Agreement fully compensate PECO for all energy and capacity and services it must provide Enron?

A. No, it would not for several reasons. First, Enron would not be obligated to purchase from PECO the power needed to serve Standard Default Service customers, but would have the right to do so. PECO thus must set aside a potentially significant portion of its generation assets just in the event that Enron decides to exercise its call for PECO to serve Standard Default Service Customer without any compensation to PECO for that reservation. As explained below, the absence of a reservation fee is totally inconsistent with how the marketplace values call contacts and options to purchase. Thus, the call contract provisions of the PPA are confiscatory as they would transfer value to Enron without any compensation to PECO.

Second, there are numerous hidden costs imposed on PECO with the Power Purchase Agreement. For example, the Power Purchase Agreement imposes all of the administrative burdens on PECO. PECO must essentially act as Enron's agent in performing all tasks of energy supply administration, including interaction with third parties and the PJM Office of Interconnection ("PJM OI"). However, the contract price structure makes no provision for PECO's recovery of these administrative expenses.

Third, the PPA appears to shift all transmission and PJM-related risks and expenses to PECO. One example is that PECO is responsible for the transmission service required to deliver power from outside PJM to the PJM border. Another is that the PPA requires PECO to procure energy from the marketplace to the extent it does not have energy and capacity on hand to satisfy Enron's requirements. However, PECO may have to purchase energy and capacity at a price above the PPA's contract price. The contract price does not include compensation for such expenses.

G. Obligations of PECO

Q. Are you familiar with the MBC Services Agreement that Enron has filed as part of the Enron Plan?

A. Yes. I have reviewed its provisions and I am also familiar with the testimony of PECO witness Brian D. Crowe with respect to that agreement (PECO St. No. 29-E).

Q. Please summarize the totality of obligations that are imposed on PECO under the Power Purchase Agreement and the MBC Services Agreement.

A. Enron would require PECO to continue to perform all of the functions it presently performs as the Provider of Last Resort in its own service territory at prices set by Enron. The only real differences in service under Enron's Plan is that PECO would be required to send out bills with Enron's name and logo instead of PECO's and Enron would insert itself between PECO, the actual service provider, and retail customers for all customer communications functions. Thus, Enron would assume the role of Provider of Last Resort in name and form only, not in fact or substance. PECO would continue to perform all the work.

Q. Please provide further details on the specific obligations that the Power Purchase Agreement would impose on PECO.

A. PECO's obligations under the Power Purchase Agreement would include the following:

- Energy Procurement. PECO must hold ready its generation to meet Enron's requirements. PECO must purchase fuel and maintain plant operations staff to meet any Enron demand under the PPA. To the extent that its own generation resources are insufficient to provide the energy and capacity to satisfy "All Requirements" of Enron for serving default service customers, PECO would have to buy energy and capacity in the marketplace to bridge the gap, while absorbing all of the cost risk of any such purchases.
- Scheduling. PECO would be responsible for scheduling the energy required to serve default customers. This includes commitment of PECO's own resources. Arrangements with PJM for energy delivery, related transmission services, needed ancillary and other pool support services, and record keeping and accounting for all energy deliveries under the PPA.
- Delivery. Enron only takes title to the power at the point of delivery to the end-use consumer. This means that PECO must make all necessary arrangements for delivering the power over transmission and distribution facilities.
- Energy and Capacity Supply. PECO would be required to keep adequate supplies of energy and capacity on hand to be able to serve all of the actual and potential Default Service Customers.

- Generation Planning. Under the Enron Plan, Enron does not assume any obligation to serve default service customers, but requires PECO to satisfy all the requirements of such customers at all times. As such, PECO also bears the implied obligation to plan its generation resources so that they are adequate to satisfy the power needs of such customers.
- PJM Obligations. PECO is responsible for satisfying all of Enron's PJM obligations as a load-serving entity, such as forecasting energy use, scheduling resources to meet energy supply obligations, arranging for transmission service within PJM and outside the region for any energy imports, meeting the PJM installed capacity obligation, complying with PJM data requirements for planning, scheduling, operations and pool accounting, and providing or paying for transmission ancillary services like operating reserves and for any other services that PJM may from time to time require.

H. Obligations of Enron

Q. Under the Power Purchase Agreement, would Enron have any obligation to purchase its "Optional Requirements" from PECO?

A. No. Enron has no obligation to buy energy from PECO to meet its "Optional Requirements." Indeed, the definition of Optional Requirements specifically provides: "Buyer shall not be obligated to purchase its Optional Requirements from Seller . . . ." PPA § 1.1 at 2.

Q. What obligation would PECO have to Enron's Optional Requirements?

A. Although Enron has defined "Optional Requirements" to exclude any obligation on Enron's part to buy energy associated with such requirements, the definition specifically states that "Buyer shall have the right to require Seller to sell to Buyer the Optional Requirements of Buyer at Buyer's option." PPA at 2. As a result, Enron has a call contract on PECO's energy and capacity resources and other services in order to serve Standard Default Service Customers for the more than ten-year term of the PPA.

Q. Does Enron make any firm commitment to purchase any quantity of power from PECO during the term of the Power Purchase Agreement?

A. No. The PPA nowhere specifies a minimum quantity of energy and/or capacity that Enron must purchase from PECO. The PPA provides only that Enron will buy its Mandatory Requirements from PECO, whatever they are. The level of these requirements would be constantly changing, and can be subject to wide swings based on factors such as the market price for energy and how Enron sets the energy price it charges Standard Default Customers. As explained in the testimony of PECO witness Dr. William Hieronymus (PECO St. 6-E), the Enron Plan in its early years would promote the migration of Transitional Default Service Customers to other Electric Generation suppliers by penalizing such customers through above market pricing. Further, when default service customers exercise their retail choice options but later return to default service, their energy requirements would be lumped in with Enron's Optional Requirements. Inasmuch as the Transitional Default Service Customers are the only grouping of default service customers for whom Enron would have Mandatory Requirements, the total amount of energy and capacity that Enron actually commits to buy from PECO is not only a moving target, it is a constantly declining one.

Q. Why then does Enron call the Power Purchase Agreement a "Firm Energy & Capacity Purchase and Sale Agreement"?

A. The word "firm" used in that context is intended to only describe the quality of the energy and capacity required to be supplied by PECO under the Power Purchase Agreement, and not Enron's commitment to buy that power.

Q. Are there any other obligations that Enron would have under the Power Purchase Agreement?

A. Apart from payment, I found no others.

Q. Is Enron's payment obligation under the PPA unqualified?

A. No. Enron can withhold payment to PECO by claiming the existence of "a good faith dispute." Further, there is no provision that Enron pay disputed monies into any kind of escrow account. In addition, § 10.2 of the PPA appears to give Enron the right to set off against its payments to PECO any claims, real or perceived, that it may have against PECO.

Q. Does PECO have a corresponding set off right?

A. The Power Purchase Agreement is not clear on that point. While § 10.2 on its face applies as equally to Enron as it does to PECO, other provisions of the Power Purchase Agreement when read together appear to say that the contract price is PECO's sole and exclusive remedy. If so, PECO would have no claim for anything other than its contract price. Thus it would appear that this section is being intended to benefit Enron only.

I. Call Contract for "Optional Requirements"

Q. Following up on your testimony that the Power Purchase Agreement is several contracts in one, including a call contract on energy and capacity, please briefly explain what a call contract is.

A. Simply, a call contract is like an option to purchase particular goods and/or services. It is an agreement between a buyer and seller of a product or service, whereby the seller agrees to hold onto the product or service for a specified time and to make it available for purchase by the buyer during that time, generally at an agreed-on price. A call contract on energy and capacity would work the same way; the seller agrees to make that energy and capacity available for a set period so that the buyer can "call" on it during that period.

Q. Please identify and describe the call contract provisions of the Power Purchase Agreement.

A. If you look for a specific call contract section of the Power Purchase Agreement, you will not find one. This is because the Power Purchase Agreement, as drafted by Enron, hides the call contract provisions within the definitions section of the PPA. I refer your attention to the definitions of "All Requirements," "Mandatory Requirements" and "Optional Requirements" contained in the PPA, and which I addressed earlier in my testimony. Those definitions, combined with PECO's obligation under the PPA to satisfy "All Requirements" of Enron, would give Enron the functional equivalent of call rights on all of PECO's generation assets.

Q. Please describe what the effects of these call right would be on PECO.

A. The immediate effect is that, under the PPA, PECO would have a legal obligation to keep sufficient energy and capacity available to satisfy Enron's Optional Requirements just in case Enron decides to call on such energy and capacity. If PECO cannot satisfy its obligation from its own generating units, it would have to purchase energy for Enron's use. And "Optional" means exactly that; Enron does not have any corresponding legal obligation to buy any of the energy and capacity that PECO must set aside for the possibility of satisfying Enron's Optional Requirements.

Q. Please explain why the Power Purchase Agreement does not compensate PECO for the call rights it gives to Enron.

A. The PPA's call contract features force PECO to remove its energy and capacity from the marketplace without any guarantee that Enron would buy that energy and capacity. While this might be convenient from Enron's perspective, PECO would suffer lost opportunity costs if Enron does not in fact exercise its call. Such lost opportunity costs would arise from the potential sales that PECO could have made were it free to offer that energy and capacity to the marketplace other than on a non-firm, hourly basis.

Q. How consistent is the absence of a reservation fee for the call rights contained within the Power Purchase Agreement with the way the marketplace values such rights?

A. It is not at all consistent. The marketplace recognizes the opportunity costs to the seller of energy through the payment of reservation fees for the right to call on energy. The size of the reservation fee will depend on a variety of factors such as the type of energy product being sold, flexibility in scheduling and the contract duration. A brokering market presently exists in which calls on energy are regularly traded.

Q. Please describe of the call contract products traded in this broker market.

A. Yes. The call contract traded in this market are fairly standardized products. These products tend to be highly structured and well defined. For instance, one product might be the right to call on "peak energy in 50 MW blocks for 16 hours a day every day for one month." In addition, the product is likely to specify time windows in which the buyer must reserve the energy for delivery. I note further that the call contract products currently in the market are usually fairly short in duration and typically do not exceed one year.

Q. What is the pricing structure for the types of call contract products available in the broker market?

A. Typically, these products have an upfront reservation fee as well as a separate price for the energy actually called on by the buyer.

Q. What variables affect the determination of a reservation fee?

A. There are many variables that can affect the fee. However, a clear correlation exists between certain features of a call contract product and the reservation fee, as follows: (1) the greater the volatility of the product, the higher the reservation fee; (2) the greater the flexibility of the buyer in exercising call option rights, the higher the reservation fee; and (3) the longer the term of the call contract, the higher the reservation fee. Generally, in setting the price of a call product, the seller is looking to reflect not just the value of the energy called upon, but also the uncertainties and risks to the seller associated with product volatility and the buyer's flexibility in exercising call rights.

Q. How do the call rights contained in the Enron Power Purchase Agreement compare with the typical call contract products in the marketplace?

A. There really is no basis for comparison, because the PPA gives Enron virtually limitless flexibility without requiring Enron to pay any reservation fee, let alone one that reflects the substantial price and performance risks being borne by PECO. The call contract product contained within the PPA is a poorly defined product, which increases the uncertainties and volatility of the PECO's delivery obligations. There are no notification limits on the call rights of Enron for Optional Requirements energy. Nor are there any provisions in the PPA that require Enron to forecast the amount of energy it will call or release capacity it will not need. It would even be possible for Enron to exercise its call on an hour by hour basis. In addition, the call contract would be in effect for a term of more than ten years. Finally, the buyer – not the seller – is dictating the price of the call product, and has set the reservation fee at zero. This is simply unheard of. It is analogous to someone receiving an option to buy your house during the next ten years and not paying a dime for that privilege.

As I explain later in my testimony, the result of the latitude that the PPA gives to Enron in exercising call rights effectively eliminates PECO as a competitive supplier for many of the more valuable wholesale energy supply products needed in the region.

Q. In your view, would PECO ever offer a call product the same as the one reflected in the Power Purchase Agreement?

A. Absolutely not. To the extent PECO ever offered a call product for energy and capacity, it would be PECO, and not the buyer, that would determine pricing, subject of course to negotiations with the buyer; there would be a reservation fee; and there would be clearly defined restrictions concerning the buyer's rights to exercise the call. Given the volatility and uncertainty around the amount of energy and capacity to be supplied to serve retail load, that reservation fee would incorporate a hefty premium.

Q. Has PECO entered into any long-term sales of capacity and energy?

A. Yes. In particular, PECO has entered into a 25 year agreement with Baltimore Gas and Electric Company (Baltimore) and a 10 year agreement with Delmarva Power & Light Company (Delmarva).

Q. Can you describe the nature of the obligations in the Baltimore contract?

A. Yes. The contract obligates PECO to supply 140 MW of capacity to Baltimore. Baltimore then has the right to call energy from PECO, at set prices and according to clear scheduling obligations. Protections are built into the contract that give PECO some certainty about the schedule of energy deliveries in the near term, while providing Baltimore significant flexibility in the long-term.

Q. How are the prices structured in the contract with Baltimore?

A. The prices include a capacity and an energy charge. The capacity charge, which acts as a reservation fee, is paid whether or not Baltimore dispatches the energy. Thus, in the event Baltimore elects to take no energy under the contract, it is still obliged to pay about 70% of the amount it would pay if it dispatched all the energy available to it. This amount varies year-to-year based on the cost of energy, but PECO anticipates that the capacity charges will not represent less than 50% of the total revenue in any given year.

Q. Is the Delmarva contract consistent with the Baltimore contract?

A. Yes, although it approaches pricing in a different fashion. The Delmarva contract has a smaller capacity charge. Some of the "reservation fee" is built into the price of energy in the contract.

Q. Therefore, can Delmarva avoid some of its capacity costs by not scheduling energy under the contract?

A. No, just the opposite. Delmarva is obliged to take 95% of the maximum energy available to it in every billing period. Thus, Delmarva has an obligation to pay at least the sum of its capacity charges plus 95% of its potential energy charges. Delmarva's discretion in dispatching energy is limited to 5% of its total potential energy take. Less than 3% of PECO's revenue stream is at risk. In addition, PECO has a unilateral right to increase or decrease the amount of capacity reserved by Delmarva, within certain prescribed limits.

Q. Can you make any conclusions from these contracts?

A. Yes. Review of these contracts, plus PECO's experience in contracting with IPP's, allows me to conclude that, in most long-term contracts the buyer takes on significant obligations. Specifically, the buyer is obliged for 50% - 100% of the total possible costs of contracts. The seller is generally protected from the buyer walking away from or shopping the deal it struck. This is a reasonable protection when the seller is committing to a long-term supply with fixed costs.

J. Conditional Nature of Enron's Commitments

Q. Is Enron making an unconditional commitment to enter into the Power Purchase Agreement?

A. No. The Power Purchase Agreement is subject to several conditions precedent. They are: (1) the final and non-appealable approval of the Enron Plan by the Commission; (2) the final and non-appealable approval PPA by the Commission and the FERC of the transactions contemplated under the; (3) PECO's execution, and delivery to Enron, of the MBC Services Agreement; and (4) the final and non-appealable approval of the transactions contemplated under the MBC Services Agreement.

Q. What is the consequence of any one of these conditions not being satisfied?

A. Unless Enron waives the condition, the Power Purchase Agreement automatically terminates. See PPA § 2.2 at 3.

Q. Apart from these conditions precedent, does the Power Purchase Agreement contain any other qualifications on Enron's commitments under it?

A. Yes. Enron has included a major "regulatory out" provision in the Power Purchase Agreement, which gives Enron the right to terminate the Power Purchase Agreement fifteen days after any order, rule or regulation that has a materially adverse effect on its rights as a default service provider under the Enron Plan. See PPA § 3.3 at 4.

Q. Does the Power Purchase Agreement define, or otherwise provide a standard for identifying, a materially adverse effect?

A. No. As such, Enron would be free to construe any unfavorable rule or regulation as materially and adversely affecting its rights as a default service provider.

Q. Putting aside the conditions precedent and the regulatory out you describe, does the Power Purchase Agreement nonetheless evidence a commitment by Enron to assume all of the obligations and liabilities of a Provider of Last Resort?

A. No. The Power Purchase Agreement goes to great lengths to ensure that such obligations or liabilities are not assumed by Enron, but remain with PECO. In particular, § 8.4 of the PPA provides as follows:

> **No Release/No Assumption**. Nothing in this Agreement shall operate or be construed to release PECO from any obligations or liabilities it can or may have in connection with the provision of energy and capacity in its service territory except as specifically provided herein or in any related agreements. By entering into this Agreement, and any related agreements, EESP does not assume, and shall under no circumstances be held liable for, any Claims against or liabilities of PECO of any kind or nature whatsoever.

In other words, PECO, not Enron, would remain the party ultimately responsible for serving customers in PECO's "service territory," notwithstanding Enron's designation as PLR.

K. Allocation of Risks

Q. How does the Power Purchase Agreement allocate risks associated with the provision of default service between PECO and Enron?

A. The Power Purchase Agreement shifts all risk to PECO. As detailed by the following, this ranges from the normal market risks related to the procurement of energy to the risk of regulatory changes. The principle risks allocated to PECO include:

- Price Risks: The Power Purchase Agreement provides PECO no protection against price risks associated with the energy procurement activities that may be required in satisfying Enron's requirements. This is particularly problematic because, in the later years of the Enron Plan, PPA contract prices are below current estimates of generation market prices. PECO would be forced to incur the higher market prices with no recovery of such costs provided for in the PPA.
- Obligation to Serve: As stated above, although Enron wants to have the title of Provider of Last Resort, it is unwilling to assume the obligations and liabilities that flow from that status.
- Energy Procurement: The PPA obligates PECO "at all times to deliver the entire Contract Quantity irrespective of whether Seller can supply such quantity from its own generation resources or must obtain energy and capacity from other sources." PPA § 4.3 at 4. In a given situation, this might mean that PECO would have to purchase and import power into PJM to satisfy Enron's requirements. However, the PPA provides no compensation to PECO for such procurement activities.
- Delivery: PECO would bear all risks associated with delivery of energy and capacity to default service customers. Under section 6.3 of the PPA, Enron would not take title to

the energy and capacity until the point of delivery to the customer. It is only at that point that "risk of loss" of the contract quantity transfers to Enron. This, however, is meaningless given that there is no risk of loss once the energy and capacity is actually delivered to the customer. Even this was not enough for Enron, however. Enron would never take responsibility for third party liability in connection with the sale even when it takes title. Instead, the PPA provides that PECO "shall be deemed to be in exclusive control (and responsible for any damages or injury caused thereby) of the energy at all times up to and including consumption by the end use customer."

- Generation Planning: Under the Enron Plan, PECO – not Enron in its role as "provider of last resort" – bears responsibility for the adequacy of generation resources needed to serve default service customers.
- PJM Obligations: Under the PPA, PECO is responsible for both the day to day administration of Enron's responsibilities to PJM and for all costs of services provided by PJM such as energy from the pool spot market, transmission ancillary services or installed capacity obligations associated with default service customers. It is proposed by Enron that PECO provide all of these services at no cost to Enron.
- PJM Capacity Derating Practices: Section 4.4 of the PPA also requires that PECO ensure that Enron receives full credit for energy and capacity covered by the PPA, including for purchases from third party suppliers that PECO might be forced to make. The effect of this language is to shift to PECO all risk associated with the practices followed by the PJM OI in valuing capacity. At present, these practices – over which PECO has no control – entail an assessment by the PJM OI as to the deliverability of the capacity resources identified by a load serving entity.

- Transmission Service Requirements: Section 6.2 of the PPA would assign to PECO all risks associated with the vagaries of transmission service including control area services, inadvertent energy flows, transmission losses and loss charges relating to the transmission" of the power.
- General Liability: I noted earlier that PECO would remain liable for any damage or injury caused by the delivery of power, even after Enron takes title to it. See PPA § 6.3. In addition, PECO must indemnify Enron and any of its Affiliates with respect to any claims for damage for injury connected to delivery of energy and capacity under the PPA even when PECO was not at fault and even when Enron is negligent. See PPA § 8.2. While there is a parallel provision to indemnify PECO with respect to claims connected to Enron's performance under the PPA, that provision is meaningless because payment would be the only real performance obligation Enron has under the PPA. Even then, Enron could evade that obligation through the so-called "good-faith dispute" provisions of the PPA.
- Regulatory Changes: Section 3.3 of the PPA permits Enron to back out of its default service provider role any time the regulatory climate changes, with as little fifteen days notice. If Enron were to back out under such circumstances, PECO would be left to deal with such regulatory changes.

L. Accountability to Regulatory Authority

Q. Based on your reading of the Power Purchase Agreement and the Enron Plan, how accountable would Enron be to regulatory bodies such as the Commission and the Federal Energy Regulatory Commission?

A. The writing is already on the wall on that issue. In its filing, Enron has made crystal clear that it is unwilling to be subject to the same level of regulatory oversight that public utilities receive. The Enron Petition is expressly conditioned on Commission's determination that "Enron as the PLR" is not "a 'public utility' under 66 Pa.C.S. § 102."

In addition, the regulatory out contained in Section 3.3 of the PPA makes clear that Enron does not want to bear the same type of regulatory risks that public utilities have been subject to for decades. If the regulatory climate changes in a manner inconsistent with Enron's then existing economic interests, Enron could readily exercise the "escape" option afforded by that section to exit from its role as a default service provider.

Q. What do you understand to be the possible consequences from a Commission ruling that Enron as the Provider of Last Resort is not a public utility?

A. In a nutshell, Enron would escape regulatory oversight of its organizational structure, its business dealings and its interaction with affiliates. For example, the Commission would be completely foreclosed from exercising its regulatory authority in connection with Enron, in its role as PLR, under 66 Pa. Cons. Stat. Ann. § 508 (to vary, reform or revise contracts in the public interest), §§ 1101 et seq. (to oversee the transfer of property used and useful in providing public service), §§ 1501 et seq. (to oversee the adequacy, efficiency, safety and reasonableness of service and facilities) and §§ 2101 et seq. (the power to oversee and approve certain contracts with affiliates).

Q. Are there any other features of the Power Purchase Agreement that undermine Enron's accountability to the Commission as the Default Service Provider?

A. Yes. One feature is that the Power Purchase Agreement allows Enron to transfer or assign the Agreement. See PPA §11.1.

A second feature is Enron's right to "transfer, sell, encumber, assign or pledge the Agreement or the accounts, revenues or proceeds, hereof, in connection with any financing transaction, or other financial arrangements."

Q. Please explain the potential pernicious effect that could result from allowing Enron to assign the Power Purchase Agreement.

A. Normally, any transfer or assignment of rights by a public utility would be subject to the review and approval of the Pennsylvania Public Utility Commission. PECO, for example, would have to obtain Commission approval to transfer or assign its property rights to another, including any affiliates, and such transfer must be consistent with the public interest and not just the private interest of the party. Under the Enron Plan, Enron contends that would be the Provider of Last Resort function, which by its very nature would be a public utility function. Nevertheless, Enron is affirmatively seeking to ensure that it is not treated as a public utility and the Enron Plan does not contemplate that status. The transfer or assignment of the PPA would not be subject to the review and approval of the Commission.

Q. What would be the significance of the Commission's inability to review a proposed transfer or assignment of the Power Purchase Agreement by Enron?

A. Simply, the Commission would have no control over who steps in to perform the provider of last resort function. Such an occurrence would be wholly inconsistent with the Commission's statutory obligations to ensure the adequacy and safety of electric supply to Pennsylvania citizens.

Q. Why would the second feature you described undermine the accountability of Enron to the Commission?

A. This provision would permit Enron to transfer or assign the revenues received by Enron from customers to third parties. Thus, under Enron's Plan, the Commission and customers within PECO's service territory could end up with a default service provider that has no assets, either physically or financially, within reach of either customers or this Commission.

M. <u>Other Terms and Conditions of Power Purchase Agreement</u>

Q. Is the Power Purchase Agreement even-handed in its description of the rights of the Parties?

A. No. The document is replete with one-sidedness. The following is only a sampling:

- The terms and conditions of the Power Purchase Agreement "must be satisfactory to EESP, in its sole discretion . . .." PPA, § 2.1(b) at 3. . PECO has no such comparable discretion under the PPA.

- Any changes made to the Power Purchase Agreement by the Commission or the FERC must be satisfactory to EESP, in its sole discretion . . . ." PPA, § 2.1 (a) and (c) at 3. PECO has no such comparable discretion under the PPA.
- Enron would have the right to back out of the arrangement in the event of any final, non-appealable order regarding the Enron Plan that "materially adversely affect[s] the rights or obligations of EESP . . . ." PPA, § 3.3. at 4. PECO has no such right.
- There are unequal remedies for breach of the Agreement. If PECO fails to deliver any part of the contract quantity, Enron has the right to recover from PECO the "replacement price" for that part not delivered, including any additional transmission charges it incurs. Even if Enron does not purchase replacement power, PECO is subject to a charge equal to the difference between the Contract Price of the "market price for such quantity of energy at such Delivery Point *as determined by Buyer* in a commercially reasonable manner. Further, to the extent Enron is unable "for any reason" to obtain replacement energy, the PPA provides that Enron "shall have all remedies available at law or in equity." By contrast, if Enron fails to satisfy any obligation, the PPA makes no mention of PECO recovering anything other than the stated contract price, and if one had any doubt that this is PECO's sole and exclusive remedy, § 12.1 – typed in capitalized letter – removes all doubt.[1] So while Enron gets to have remedies at law or equity for breach, PECO's are "waived."
- As detailed above, Enron would shift to PECO virtually all of the risks and obligations associated with the transactions contemplated under the Power Purchase Agreement.

[1] That section provides that where the PPA sets forth "an express remedy or measure of damages" for any breach of any provision, that "such express remedy or measure of damages shall be the sole and exclusive remedy, the obligor's liability shall be limited as set forth in such provision and all other remedies or damages at law or in equity are waived."

- Enron's indemnification protections would extend to its affiliates; PECO's does not. See PPA § 8.2-8.3.
- If Enron defaults on its payment obligation, it would get a cure period and the right to call it a good faith dispute with impunity. If PECO were to fail to deliver the contract quantity of energy and capacity, there would be no cure period and Enron gets to terminate. See PPA Article 9.
- Even though PECO must have the supply available at all times, Enron doesn't have to purchase or pay for the energy and capacity for all the default customers, only some of them.

N. Adverse Impact on Generation Marketplace

Q. At page 6 of his testimony, Enron witness Kean states that "the Choice Plan is . . . focused on the development of a competitive market in PECO's service territory." (Enron St. No. 1). As far as the Power Purchase Agreement is concerned, does the Enron Plan accomplish that end in your view?

A. No. It is my view that the Enron Plan is anticompetitive. I reach that conclusion for two reasons. The Power Purchase Agreement gives Enron the power to "hold hostage" PECO's energy and capacity that could be called upon to satisfy Enron's "Optional Requirements" associated with the delivery of energy services to Transitional Default Service Customers. This category of "Requirements" is likely to expand over time as consequence of the Enron Plan's pricing structure. As stated by Dr. Hieronymus in his testimony, this pricing structure would tend to drive retail customers away from default service in the early years of the Enron Plan, but would drive them back in the later years. (PECO St. 6-E). If they return to default service they would be categorized as a Standard Default Service Customer unless they sign an one-year contract with Enron.

As a result of likely expansion of the Standard Default Service customer class, the unpredictable nature of estimating the energy and capacity needed to satisfy their requirements, and the onerous penalties associated with a failure by PECO to deliver even Optional Requirements, PECO would be obligated to have such energy and capacity on hand and available to Enron even if Enron has no intention of calling on it. Thus, at no cost to itself, Enron can keep PECO from marketing energy and capacity freed up by departing retail access customers. This power effectively prevents PECO from competing with Enron, EPMI or Enron's other affiliates in the marketing of electric energy both at wholesale and at retail. It also denies Enron's or EPMI's other competitors access to PECO's energy and capacity.

This outcome is especially ironic given Enron's recent complaints regarding the availability of energy and capacity to serve load in the Pennsylvania retail access pilot programs. Indeed, Enron has gone as far as requesting that FERC "order" PECO and other PJM utilities to sell energy and capacity into the pilots. It would appear that Enron at least believes that access to PECO's energy and capacity is a vital resource in the marketplace. However, through the Power Purchase Agreement Enron, at no cost to itself, seeks to exercise exclusive control over that resource, with the ability to prevent PECO from making that resource available to the marketplace, at Enron's discretion.

Q. At page 17 of his testimony, Enron witness Bohi states: " Under the Choice Plan, PECO will be required to provide a full requirements contract to Enron for the needs of the Default Service customers. . . . PECO would sell the remainder of its output to marketers, both to affiliated and independent marketers, on and off its system, under similar terms and conditions." (Enron St. No. 3). *Do* you agree with Mr. Bohi's statement concerning PECO's ability to sell the remainder of its output?

A. No. PECO's ability to sell the remainder of its output would be severely hampered by the unlimited nature of Enron's call rights under the Power Purchase Agreement as well as by the distortive effects of the Enron's Plan's pricing structure on shifts in retail load.

Q. Does the Enron Plan present any code of conduct concerns?

A. Yes. PECO witness J. Gregory Sidak (PECO St. 10-E) testifies about the potential code of conduct concerns associated with the Enron Plan. I further note that in its October 1, 1997 application at the FERC for market-based rates authority, Enron did not propose to adopt any type of code of conduct that would govern its relations with any of its affiliates. All Enron did was file a code of conduct that would apply to the relationship between Portland General Electric Company and its affiliates.

Q. Why wouldn't the PGE Code of Conduct be sufficient?

A. Enron in its stated role as PLR for PECO's service territory would still be able to pass on nonpublic information and transfer value to affiliates such as Enron Power Marketing Inc. without any violation of that Code.

Q. Does the Enron Plan raise any additional concern related to Enron's dealings with it affiliates?

A. Yes. I noted in reviewing the Power Purchase Agreement that Enron has included a definition of affiliates that, as far as my experience is concerned, is unusual given the substantially high threshold for finding affiliated status. Enron defines an affiliate as "[a]ny person that directly or indirectly Controls, is Controlled by, or is under common Control with the person in question[.]" PPA § 1.1 at 1. Thus, instead of the 5 to 10% threshold frequently used to establish affiliation, Enron is proposing a 50% threshold. Under Enron's definition of affiliate, two corporations 45% of whose outstanding voting securities are under common control would not be deemed to be affiliates. This definition is also utilized in the MBC Services Agreement that Enron has proposed as part of the Enron Plan.

Q. What is the significance of this higher control threshold for affiliate status?

A. The higher the threshold, the greater the number of potentially affiliated transactions removed from the oversight of the Commission. Considered in tandem with Enron's failure to propose a code of conduct to govern its relations with its affiliates, this definition raises the question of whether the Commission would even be advised of all the affiliate transactions in which Enron might be engaging. Indeed, given that Enron is demanding that the Commission find it not to be a public utility, it appears that under the Enron Plan, the Commission would be completely foreclosed from overseeing Enron's dealings with its affiliates pursuant to 66 Pa. Cons. Stat. Ann. § 2101 et seq.

O. Evaluation of Power Purchase Agreement as a Whole

Q. At page 9 of his testimony, Enron witness Slater states that he does "not see why a prudent manager would not sign" the Power Purchase Agreement." (Enron St. No. 4). Do you agree?

A. Absolutely not. The Power Purchase Agreement is so completely one-sided, oppressive and confiscatory that such a contract could not occur through freely negotiated arms length dealings between parties of equal bargaining positions. In fact, I would be surprised if Enron has ever made the same types of commitments in its power sales agreements as it seeks to impose on PECO. As far as I can see, there is no value created by this agreement for either PECO or default service customers. Instead, it allows Enron to get "money for nothing" by taking value from the pockets of PECO's shareholders for the benefit of Enron's shareholders.

III. RELIABILITY AND SAFETY IMPLICATIONS

Q. In your view, how would the Enron Plan, and the Power Purchase Agreement in particular, affect the level of reliability and safety in the provision of electric service to customers in PECO's service territory.

A. It would undermine the reliability and safety of such service for several reasons. First, the terms of the Power Purchase Agreement are so oppressive and unfavorable to PECO that it may cause irreparable financial harm to PECO. (See PECO St. 20-E). In that event, PECO may be rendered unable to perform the type and level of functions it performs now in its current role as provider of last resort. This is a critical point given that even under the Enron Plan, it is PECO, and not Enron, that would be performing all of the Provider of Last Resort functions in fact and substance.

Second, under the Enron plan, the Electric Generation Suppliers would be the sole point of contact with retail consumers. Thus, EGSs would be interposed between PECO and all retail access customers with respect to virtually all communications, even where such communications relate to PECO's performance of its obligations as the Electric Distribution Company. In that role, for example, PECO needs to have unfettered access to information regarding system problems and outages. By putting marketers in the middle, the Enron Plan may impede such communications, thereby creating an unsafe and unreliable system conditions. In particular, the relaying of information from customers to EGSs to PECO may delay PECO's timely receipt of crucial information necessary to prevent or mitigate system problems. In addition, customers' efforts to communicate their concerns may be frustrated by their inability to reach the various EGSs. Enron's total lack of accountability to the Commission and Pennsylvania citizens as discussed above provides little comfort that Enron would be around to pick up the pieces when problems materialize.

Third, Enron has provided the Commission with no information as to how emergency calls would be handled. Enron itself has no employees who are located in Pennsylvania and who would be familiar with the both the physical electric infrastructure and weather within PECO's service territory. Indeed, I note that in its application to obtain a license to become an EGS in

Pennsylvania, Enron identified a person located in its Houston, Texas office as its "Pennsylvania Emergency Management" contact person.

Fourth, from a planning perspective, the Enron Plan and the Power Purchase Agreement in particular may undermine the adequacy of electric supply. Under the Enron Plan, it is PECO and not Enron who would have the obligation to serve. At the same time, however, the Power Purchase Agreement encumbers PECO's ability to plan for the generation needs of default service customers by: (1) providing Enron with call rights that allow Enron to make call decisions down to the wire with no lead time for PECO to respond and (2) introducing pricing distortions that drive retail access customers back to default service in the later years of the Enron Plan, further exacerbating problems associated with forecasting load.

I note further that the pricing distortions introduced by the Enron Plan appear to conflict with Enron's witness Dr. Bohi's testimony on the expected benefits of competition. At page 4 of his testimony, Dr. Bohi states: "The benefits expected from competition follow from the more efficient operation of the electricity market in PECO's territory. By efficient operation of the market, I mean that the supply of electricity would be produced and distributed at minimum cost, subject to standards of reliability and quality of service, and that the supply of electricity would be allocated to its highest-valued uses." (Enron St. No. 3). However, based on Dr. Bohi's testimony, the Enron Plan would not produce efficiencies because consumers and EGSs would be responding to incorrect price signals; as such, the Enron Plan would deny them the "benefits expected from competition."

Q. What significance does all of this have with respect to the Commission's recent proposed rulemaking on electric service reliability?

A. As PECO witness J. Barry Mitchell testifies (PECO St. 20-E), the Enron Plan would impair PECO's financial integrity. As a result, PECO may not be able to conform to the standards to be set by the Commission in connection with its Proposed Rulemaking on Electric Service Reliability Standards ("Proposed Rulemaking"). Given further that Enron has taken every opportunity in drafting the Power Purchase Agreement to escape accountability to the Commission, there is no assurance that Enron would step in to implement standards that come out of the Proposed Rulemaking if PECO is unable to perform. Such an outcome could contravene both the expectations of the Pennsylvania legislature as reflected in the Competition Act, and those of the Commission as expressed in the Proposed Rulemaking.

IV. INADEQUACY OF PROCEDURES TO ENSURE DIRECT ACCESS

Q. In a retail choice environment, are there specific obligations for both the Electric Distribution Company and individual EGSs?

A. Yes. Close coordination is required so that all supply and delivery parties know their specific responsibilities, and to make sure that all customers are being supplied reliably.

Q. How were these responsibilities identified in the PECO pilot?

A. PECO developed a Policies and Procedures ("P&Ps") document as part of its pilot implementation plan. This document enumerated each element of the supplier administration process – the steps necessary for Electric Generation Suppliers to identify their customers, coordinate energy forecasting and supply with both PECO and PJM, account for actual energy use by their customers, and provide and receive other related services.

Q. Has Enron proposed a set of policies and procedures comparable to those contained within the PECO Pilot P&Ps for Electric Generation Suppliers as part of the Enron Plan?

A. No.

Q. Has Enron addressed the coordination among PECO, PJM and Electric Generation Suppliers in any way in its Plan?

A. In its proposed distribution tariff rule 3, Enron included a subset of the P&Ps from the PECO pilot filing.

Q. What is your view of the supplier administration process as proposed by Enron?

A. The supplier administrative process proposed in the Enron Plan is seriously deficient. Several important process steps are not addressed in any way. Even the process steps addressed in the Enron Plan have been modified with no explanation given. Also, the limited P&Ps proposed by Enron are misplaced. Rather than offer a coordinated view of the supplier administrative process, Enron has buried its version of wholesale supplier P&Ps among several sections of the retail tariff it has proposed for PECO. As such, Enron's version of supplier responsibilities is incomplete and confusing.

Q. Which existing supplier administrative processes did Enron delete from its retail choice proposal?

Enron did not address obligations to become a valid EGS, EGS obligations to meet PJM requirements (such as obtaining and scheduling transmission service and maintaining installed capacity obligations for regional reliability), the duty of EGSs to cooperate with PECO and PJM during periods of system emergency, limits on commercial use of customer data provided by PECO, and billing responsibilities of EGSs for services supplied by PECO.

I note that most of these deleted processes are not associated directly with the details of serving individual retail electric customers, and therefore do not fit well in a retail customer tariff format. However, it is important that interactions on the wholesale level be well understood and agreed to by all parties so that the ultimate supply of energy to individual retail customers would work smoothly. Whether by design or oversight, the Enron proposal omits assignment and coordination of key EGS responsibilities at the wholesale level.

Q. Why is Enron's method of dealing with PRPs through only a few rules set forth in a retail tariff a mistake?

A. Compared with energy supply by a franchised utility, energy supply in a retail choice environment is administratively more complex, and potentially more prone to supply problems unless all responsible parties know and meet their obligations. All parties involved in providing energy services to retail customers have specific responsibilities to each other, to parties such as PJM, and especially to the end use customers receiving the services. These responsibilities must be laid out in a clear way so that individual entities cannot shirk their responsibilities or "lean" on the resources or efforts of others. The Enron construct of blending wholesale and retail business relationships and market responsibilities in a the retail tariff applicable only to PECO as the EDC is both confusing, and would likely lead to continuing disputes and litigation.

Q. Does this conclude your testimony?

A. Yes