R-00973953
PECO STATEMENT NO. 2-R
Phila. 10/14/15/16/97
E. Holbert

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

ALFRED A. MILLER

Regarding Unbundling Methodology, Treatment of Large Interruptible Load Rider and Special Contract Customers, Compliance with the Commission's Order Approving PECO Energy Company's Restructuring Plan, and FERC Jurisdictional Matters

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REBUTTAL TESTIMONY OF ALFRED A. MILLER

I. INTRODUCTION

Q. Mr. Miller, did you present written direct testimony in this proceeding?

A. Yes. My direct testimony was submitted with PECO's April 1, 1997 restructuring filing as Statement No. 2.

Q. What issues will you address in your rebuttal testimony?

A. I will address the following issues, which various intervenors raise in their direct testimony:

1. The appropriate methodology to unbundle PECO's rates;
2. The treatment of customers currently under contract pursuant to the Large Interruptible Load Rider ("LILR"), the Economic Efficiency Rider ("EER"), and the Incremental Process Rider ("IPR");
3. Compliance with the Commission's Final Order on PECO's Restructuring Plan; and
4. FERC jurisdictional matters.

II. UNBUNDLING METHODOLOGY

Q. How did PECO propose to unbundle its rates?

A. As explained in William F. Sundermeir's direct testimony (PECO St. 13), PECO proposed first to determine distribution and transmission rates, then CTC charges based on a levelized annual CTC revenue requirement, and finally Electric Generation Charges that customers would pay PECO. Mr. Sundermeir designed the Electric Generation Charges and CTCs to ensure compliance on a customer-by-customer basis with the generation rate cap provisions of the Competition Act.

Q. Has PECO revised its approach to unbundling?

A. No, except to the extent that the unbundling is affected by PECO's revised approach to retail transmission service access, which Mr. Pratzon addresses in his rebuttal testimony (PECO St. 21-R). PECO stands by its fundamental approach to unbundling, which is to establish one set of CTC charges designed to recover the same CTC revenue requirement in each year of the seven year recovery period, and then establish one set of retail Electric Generation Charges which, when added to the CTC charges, will not exceed the rate cap established by the Competition Act.

Q. Several intervenor witnesses have objected to this approach. Please comment.

A. Their primary contention is that competition will be hindered under PECO's approach because the proposed levelized Electric Generation Charges are lower than the prices they believe suppliers will be able to offer PECO customers. On this basis, they conclude that PECO should have first determined a "market" price, and then determined CTC charges. Some intervenors propose that PECO charge actual market prices for energy provided to such customers, while others propose that PECO charge a "market" price set by the Commission. Those that suggest the latter method propose that the "market" price be derived using their witness's market price projections. With respect to the CTC, some accept PECO's proposed levelized CTC charge, and some propose that the CTC decline each year by an amount corresponding to the annual increase in their proposed Commission-set "market" price.

Q. Do you agree with the intervenors' unbundling proposals?

A. No, for several reasons. First, if PECO's CTC revenue declines each year, it is possible that in later years the allowed level of CTC/ITC revenue would not be sufficient to pay the costs associated with assets that PECO is ultimately allowed to securitize. Such an outcome would be inconsistent with the spirit and intent of the Competition Act, one of the principal features of which is the right to securitize.

Second, the approach PECO has recommended is the only method that allows PECO to recover all of its transition or stranded costs while complying with two important features of the Competition Act - - (1) the 7-year CTC recovery period (1/1/99 through 12/31/05) and (2) the generation rate cap. The Competition Act gives PECO the right to recover the amount of stranded costs that the Commission determines is just and reasonable. According to PECO's testimony in this case, that amount should be $6.805 billion. PECO could not recover $6.805 billion in stranded costs during the seven year transition period if it were to charge increasing "market" prices given the corresponding declining CTC charges that would be necessary to comply with the generation rate cap. In fact, we have calculated that the intervenors' recommendation would result in a shortfall in stranded cost recovery of over $2.29 billion. I have attached as Exhibit AAM-3 two charts that together show graphically how and why PECO cannot recover all of its stranded costs in seven years and also comply with the generation rate cap if it is forced to charge declining CTC prices. I have also attached a summary of primary objectives and required mechanisms for retail rate unbundling (Exhibit AAM-4).

Finally, I note that even if suppliers were unable to attract as many customers as they would like during the CTC recovery period, it is not "competition" that would suffer. Rather, it is those consumers protected by the generation rate cap that would benefit, because they would pay less to PECO alone than they would if they chose a competitive supplier and only paid PECO for its regulated unbundled charges. That is, such customers would pay less for their electricity under the rate cap than they would if they were paying market generation prices. The point of competition is to benefit consumers; not to benefit a particular supplier or suppliers. The Competition Act was not enacted so that out-of-state companies could make money at the expense of Pennsylvania's consumers. If that means that consumers benefit principally because of the generation rate cap during the transition years, and because of the efficiencies that competition will bring thereafter, then the purposes of the Competition Act will have been well-served.

Q. Is there a provision in the Competition Act that would allow PECO to charge the intervenors' proposed "market" prices while also ensuring full recovery of PECO's stranded costs?

A. Yes. In Section 2802(B) the Competition Act provides that the Commission, for good cause shown, may extend the seven-year CTC recovery period.

Q. Is some form of the intervenors' proposed unbundling method appropriate if the Commission were to grant such an extension?

A. Yes. However, the Commission's Final Order on PECO's restructuring plan would have to contain specific language guaranteeing PECO's right, following the end of the seven-year period, to continue charging a CTC for the period of time necessary to recover the balance of its stranded costs

Q. How would PECO propose to adapt its levelized CTC collection methodology to provide for changing market prices?

A. Instead of charging its proposed level Electric Generation Charges, PECO would charge market prices for the energy it sells to customers. If the sum of the market price and the levelized CTC charge were to exceed the generation rate cap, to ensure compliance, PECO would use an adjustment mechanism to credit the bills of protected customers. This "rate cap adjuster" would be applied monthly or, if the Commission would prefer, on an annual basis, and would be calculated in much the same way that the "E" factor portion of PECO's former Energy Cost Adjustment was determined.

Under this approach, PECO would not apply the rate cap adjuster to the bills of those customers who obtained competitive supply but then returned to PECO because the generation rate cap does not apply to these customers. PECO would only apply the rate cap adjuster to the bills of those customers who never leave PECO for their energy supply to comply with the generation rate cap provisions of the Competition Act.

Q. Please summarize the benefits of this proposal.

A. The proposal allows PECO to offer market prices and recover its stranded costs, while also ensuring compliance with the generation rate cap. All customers, whether they are served by PECO or not, would pay "market" prices for energy.

Q. If the Commission were to adopt this alternative method, will PECO forego recovery of any revenue shortfall caused by application of the rate cap adjuster?

A. No. PECO expects that the Commission would permit recovery of such amounts through CTC charges that it would impose beyond December 31, 2005.

Q. Do you have any further comments regarding the alternative unbundling methods proposed by the intervenors?

A. Yes. PECO strongly disagrees with the methods employed by Messrs. Baron, Johnstone and Ms. Smith to develop regulated retail market prices for the reasons explained by Mr. Sundermeir in his rebuttal testimony (PECO St. 13-R).

In addition, Mr. Boonin presents an unbundling proposal that is similar in many respects to those of Messrs. Baron, Johnstone and Ms. Smith, except that Mr. Boonin proposes to employ an hour-by-hour determination of market price for all customers. I would like to note several specific concerns with his methodology.

First, his proposal to collect generation-related CTC on a kWh only basis, rather than using blocking and demand billing, would cause intraclass cost shifting, as discussed in Mr. Sundermeir's rebuttal testimony (PECO St. 13-R). Second, the mechanics of his proposed CTC reconciliation methodology utilizing hourly energy prices is far too complex to implement without all customers having continuous demand interval meters. Currently less than 1% of PECO's customers have such meters and it is highly unlikely that these meters would be in place for all customers throughout the entire CTC recovery period. Finally, to limit severely the securitization of generation-related assets as he recommends would eliminate the possibility of achieving significant customer savings from the process.

III. LARGE INTERRUPTIBLE LOAD RIDER AND SPECIAL CONTRACT CUSTOMERS

Q. Several intervenors have objected to PECO's proposals regarding the treatment of special contract and Large Interruptible Load Rider (LILR) contracts. Please comment.

A. Yes. PAIEUG witness Baron has proposed that LILR customers be allowed to obtain competitive supply and pay no CTC for a significant portion of their load --

in most cases, almost a third of the load of these large customers would be exempt from CTC charges. Mr. Baron's argument in support of this proposal is that the revenue recovered by the CTC will in part compensate PECO for embedded generation costs not recoverable in a competitive market, and that LILR customers did not cause such costs due to their interruptibility. (PAIEUG St. 1, pp. 46-48).

Q. Do you agree with his contention?

A. No. PECO believes that the LILR customers should pay a reasonable, fair share of CTC costs. As PECO argued successfully in a recent case before this Commission, (Docket No. R-00943281, Order entered January 2, 1996), LILR customers do cause generation costs, even in the on-peak period during the summer, and therefore should contribute to their recovery.

Q. How does PECO propose to unbundle the LILR for a customer who remains on the rider?

A. As we have stated previously, a current LILR customer who chooses to remain on the rider may do so throughout the CTC recovery period. For a customer who remains on the LILR, delivery charges will be assessed on the customer's on-peak, peak registered demands as well as the customer's total energy consumption. For on-peak consumption only, the customer's CTC charge will be the difference between the one cent adder to the PJM market-clearing price that the customer is currently paying and the sum of the unbundled delivery charges. For off-peak consumption only, the customer's CTC will be based on the customer's billed demand as well as the customer's off-peak energy consumption but under no circumstances would the off-peak CTC be negative.

Q. How does PECO propose to treat an LILR customer that chooses to take supply from a new supplier?

A. Because in such situations PECO loses the benefit of the customer's willingness to interrupt when there is a generation emergency, PECO will add the cost of a peaking unit to the CTC of an LILR customer who takes alternate electric supply. As stated in the LILR case, the benefit of being able to interrupt the customer has allowed PECO, in its system planning, to reduce the projected customer demand on the system. The valuation of this benefit is based on the avoided cost of a peaking unit. If an interruptible customer leaves the PECO generation system, however, because there is no longer an avoided cost, it is necessary to recover the cost, from that former customer.

Q. How then does PECO propose to unbundle the LILR for such a customer?

A. The unbundling in this case would be identical to that for a customer who remains on the rider except for one difference: PECO will charge the customer as an additional CTC cost the level, annual carrying charge of a peaking unit multiplied by the customer's expected interruptible load, and then divided by the customer's total energy consumption. Exhibit AAM-5 contains sample calculations using these proposed unbundling methods for both customers who remain on the rider and customers who choose alternate supply.

Q. Does your suggested approach to unbundling LILR contracts violate the rate cap on generation charges?

A. No, it does not. Due to the CTC charges, the customer may pay more if it chooses to obtain competitive supply; but the rate cap on generation charges does not apply in such circumstances - it only applies when PECO supplies the customer's generation. As I stated in my direct testimony, after all rates and appropriate riders are unbundled (as of January 1, 1999), PECO will not charge a customer who chooses to remain on the LILR more than the customer would have paid had the LILR remained a rider to bundled Rate HT.

Q. Please summarize the positions taken by the opposing parties with respect to the treatment of special contract customers.

A. Mr. Baron recommends that PECO allow EER customers to obtain access to competitive supplies and that the unbundled CTC and delivery charges applicable to such customers should reflect the same discount that is embedded in their current contract rates. Enron witness Dirmeier proposes that customers who entered into special contracts following the passage of the Competition Act be allowed to rescind those contracts and obtain competitive supply. Mr. Dirmeier also proposes: (1) that the floor price for such contracts be the sum of PECO's current projections of its unbundled charges for transmission, distribution, and market-priced energy; (2) that PECO be forced to allow suppliers such as Enron to learn the details of any current proposed contracts and be allowed to bid for the customers' business before the phase-in to direct access begins; and (3) that PECO assign any contract it enters into following this "bidding" process to a competitive division or affiliate when direct access begins, which competitive affiliate would then have to remit the imputed transmission and distribution charges to PECO.

Q. Do you agree with these proposals?

A. No. First, with respect to Mr. Baron's proposal I do not believe that customers should have an automatic right to obtain competitive supply if their current contract with PECO contains provisions expressly dealing with the question of access. Such provisions should be honored, and the sanctity of these contracts should be upheld. Customers entering into such contracts obviously did so knowing full well that retail competition was a possibility during the proposed term of the contract, and therefore made a conscious choice to forego an unfettered right of access by instead agreeing to PECO's contract proposal.

Second, all special contract customers with contracts that did not anticipate access -- that is, their contracts contain no provision governing access rights -- should be allowed to obtain competitive supply, but not in the manner proposed by Mr. Baron. Rather, such customers should take unbundled service from PECO under their applicable base rates, which in most cases is Rate HT. As with the LILR, to comply with the rate cap, PECO will allow such customers to keep their contract rates on an unbundled basis only if they choose to remain with PECO for the balance of the contract term. Should the customers remain with PECO, the

Company will unbundle the contracts by discounting the customers' CTC charges to achieve the same discount from base rates that the customers currently receive.

Q. What is PECO's position regarding Mr. Dirmeier's proposals?

A. PECO adamantly opposes allowing customers that entered into contracts following passage of the Competition Act to rescind their contracts. PECO also adamantly opposes allowing Enron and other suppliers to learn the details of outstanding PECO contract proposals and bid for the customers' business. Customers that have recently signed contracts were fully aware of the existence of the Competition Act, and made a choice to enter into contracts with PECO nonetheless. The same is true of any customers that may be considering PECO proposals now. If such customers prefer to wait for the beginning of the phase-in of Direct Access on January 1, 1999, they can do so.

PECO agrees with Mr. Dirmeier's position that all special contract proposals should cover at least current projections of unbundled delivery and energy charges that customers are likely to pay, and PECO has been interpreting its special contract rate tariffs in this manner. PECO does not agree, however, that such contracts should be assigned to PECO's competitive supply group or division. There is no need to do this, as the customers' contracts will be unbundled, and as delivery and CTC charges will be accounted for appropriately by PECO.

IV. COMPLIANCE WITH RESTRUCTURING PLAN ORDER AND FERC JURISDICTIONAL MATTERS

Q. Several opposing party witnesses have criticized PECO for not submitting for comment and resolution comprehensive tariff provisions setting forth the terms and conditions of its relationship with customers and suppliers. Please comment.

A. As I indicated in my direct testimony, following issuance of a final order in this proceeding, PECO will prepare two tariffs that will codify the rules, regulations, procedures, and charges that conform to the requirements of the Commission's final order, and include them with a compliance filing. One will be the Customer Distribution Services Tariff ("Customer Tariff"). That tariff will contain all of the rights and obligations applying to the relationship between PECO and customers and over which the Commission has jurisdiction. The other will be the Supplier Services Tariff ("Supplier Tariff"). It will contain all of the rights and obligations applying to the relationship between PECO and competitive suppliers and over which the Commission has jurisdiction.

Q. Do you agree that all of the details of the two tariffs should be decided in this proceeding?

A. No, for several reasons. First, most, if not all, of the items that will be in such tariffs are already being considered and decided in this proceeding. Moreover, those items that are not at issue in this proceeding are, for the most part, being considered by working groups sponsored by the Commission. As such, the most sensible approach is to wait until all of the issues are decided in the context of this proceeding or as a result of formal Commission actions based on the recommendations of the working groups, and then memorialize the results in two tariffs submitted to the Commission for approval as part of a compliance filing. As I stated in my direct testimony (PECO St. 2), PECO's most recent bundled electric service tariff will be used as the starting point for developing the Customer Tariff.

Second, as the two tariffs proposed by Enron amply demonstrate, consideration of tariffs could confuse and needlessly complicate the resolution of many of the underlying issues. The distribution services tariff Mr. Reising proposes assumes that metering, meter reading, and billing functions will be unbundled and made subject to competition. The proposed tariff goes so far as to define the "Customer" with whom PECO must deal as the supplier, and requires that PECO provide all charges to the "Customer," rather than the "End-User," on a monthly basis. But this type of structure and provision would only be appropriate if Enron is successful in its efforts to convince the Commission that all billing should be competitively provided by suppliers. Because of the enormity and breadth of the issues that will be decided, and the value of avoidance of a process that could yield final rules that are unintentionally inconsistent with final tariffs, the Commission should postpone the codification of the rules it is deciding until after it decides what those rules should be.

Finally, I note that I have attached as Exhibit AAM-6 tariff rate sheets which reflect rates based on revised numbers contained in Mr. Sundermeir's Exhibit WFS-10.

Q. **Notwithstanding your view that it is not in the public interest to decide the details of the tariffs in this proceeding, does PECO have any specific concerns about the tariffs proposed by Enron that it wishes to bring to the Commission's attention now?**

A. Yes. Mr. Sundermeir critiques Mr. Reising's proposed tariff in his rebuttal testimony (PECO St. 13-R) and identifies additional substantive rules and regulations that must be included in the future Customer Tariff (Exhibit WFS-5 and WFS-6). In addition, Mr. Pratzon (PECO St. 21-R) reviews Enron's proposed Supplier Tariff.

Q. **In light of recent rulings by the Federal Energy Regulatory Commission (FERC) and recent FERC-ordered changes in the structure of the PJM power pool, has PECO revised its approach to retail transmission access?**

A. Yes. PECO has modified its original proposal, which I presented in my direct testimony, to satisfy concerns raised by intervenors. Mr. Pratzon presents PECO's approach in detail in his rebuttal testimony.

V. CONCLUSION

Q. Mr. Miller, does that conclude your rebuttal testimony?

A. Yes, it does.

Exhibit AAM-3

PECO Energy Company
Proposed Generation Rate Design

(Based upon the April 1, 1997 filing)

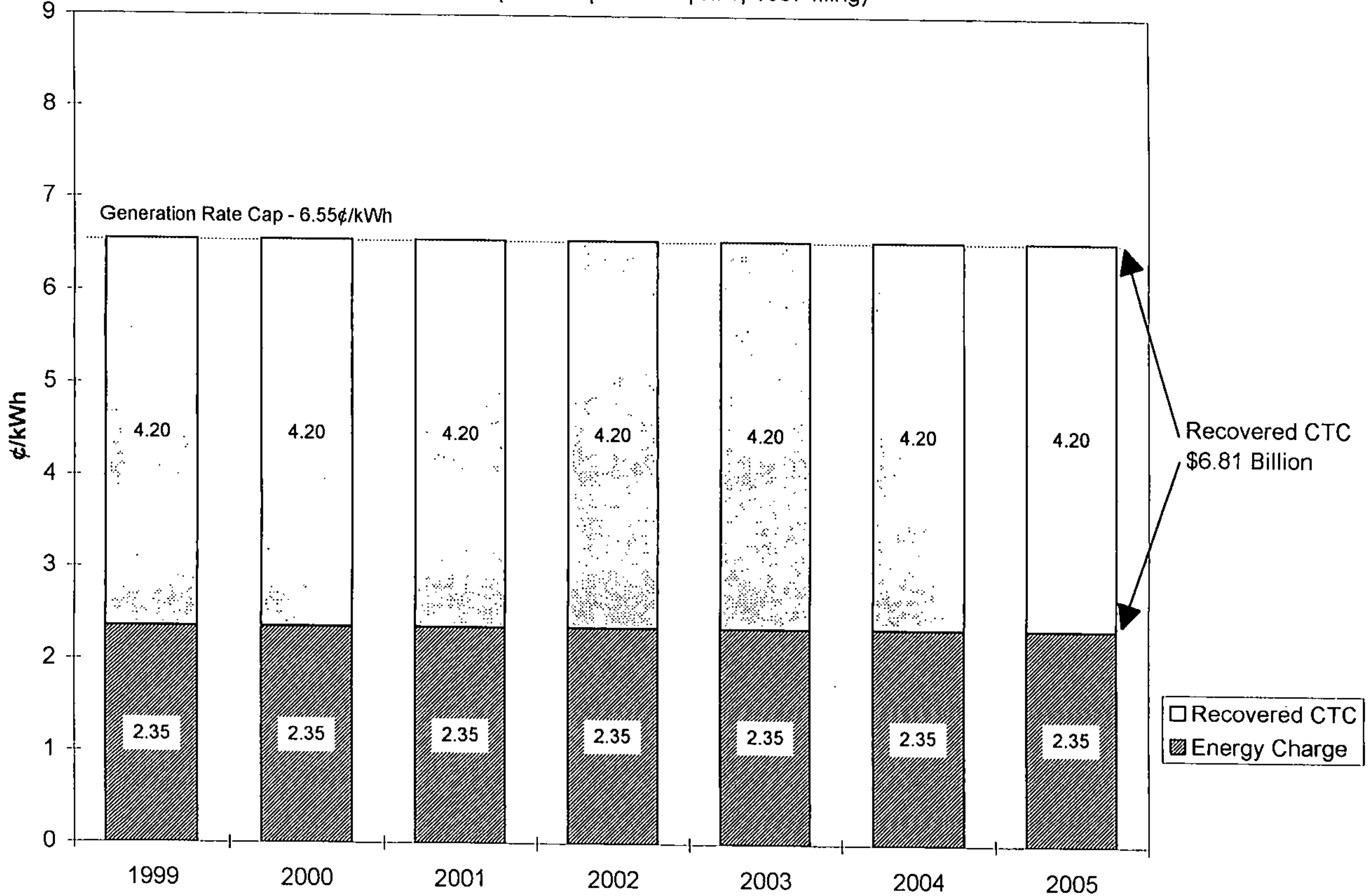
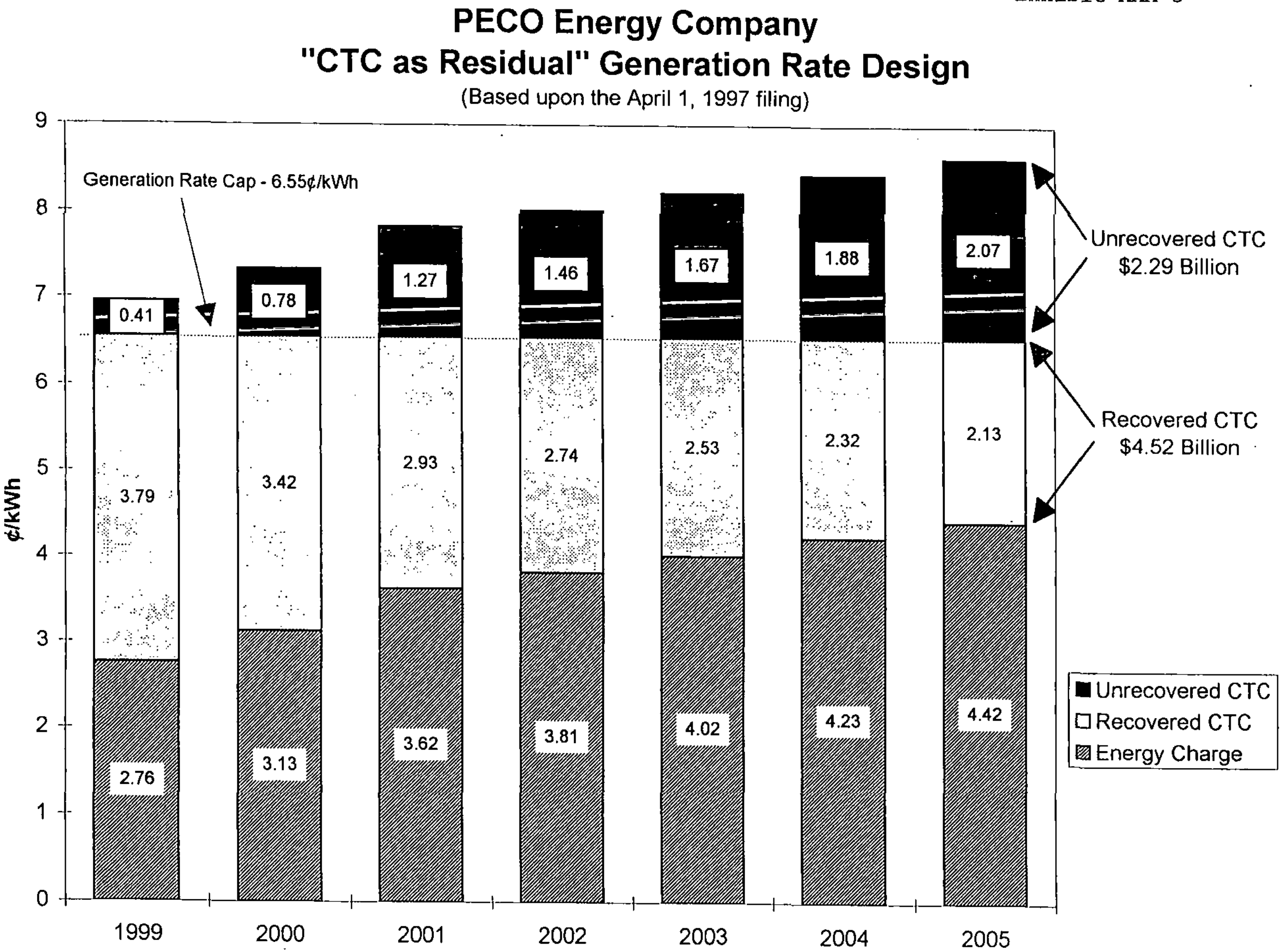


Exhibit AAM-3



Primary Objectives, During Transition Period, Of Retail Rate Unbundling (Justifications and Required Mechanisms)

Objectives Specified in Competition Act	Justification	Required Mechanism(s)
Rate Cap	Consumer Protection	Level Market Generation Rate, or Periodic Cap Adjustment; Energy Blocking Consistent with Current Rate Design
7-Year CTC Recovery (Unless Extended for Good Cause)	Unconditional Right to Recover Just and Reasonable Stranded Costs, as Determined by PUC	Level, Annual Payments, or Extension of Recovery Period

Unbundling of the Large Interruptible Load Rider (LILR)

Case 1: A current LILR customer chooses to stay on the rider and continue to take generation service from PECO. The customer's unbundled delivery charge would be based on registered, on-peak peak demand and total kWh consumption. The CTC charge would be 1¢ minus the delivery charge for on-peak consumption, and the regular HT CTC charge for off-peak consumption, using billed demand.

Example

Registered, on-peak peak demand (kW)	60,000	
Off-peak energy share	69%	Based on historic data
Billed demand (kW)	25	
Total kWh	30,660,000	Assumes 70% load factor, 730 hours
First block kWh	9,000,000	150 * registered, on-peak peak demand
Second block kWh	7,500,000	150 * registered, on-peak peak, but not to exceed 7.5 mKWh
Third block kWh	14,160,000	Total less first and second blocks

Variable distribution charges - PECO		
Demand	$1.790	$/kW-month
Energy - block 1	$0.009700	$/kWh
Energy - block 2	$0.005800	$/kWh
Energy - block 3	$0.001900	$/kWh
Variable distribution bill		
Demand	$107,400	
Energy - block 1	$87,300	
Energy - block 2	$43,500	
Energy - block 3	$26,904	
Total	$265,104	
Average bill	$0.008647	$/kWh
CTC for on-peak consumption	$0.001353	$/kWh

CTC charges - PECO - off-peak consumption		
Demand	$7.63	$/kW-month
Energy - block 1	$0.041400	$/kWh
Energy - block 2	$0.024800	$/kWh
Energy - block 3	$0.008300	$/kWh
CTC bill - off-peak consumption only		
Demand	$191	
Energy - block 1	$155	
Energy - block 2	$93	
Energy - block 3	$175,568	
Total CTC bill	$176,007	
Average bill	$0.008320	$/kWh

Total unbundled bill - on-peak	
Distribution	$0.008647
CTC	$0.001353
Market generation - variable hourly	
Total	$0.010000
Total unbundled bill - off-peak	
Distribution	$0.008647
CTC	$0.008320
Market generation	$0.010410
Total	$0.027376

Case 2: A current LILR customer chooses to leave the rider and take generation service from an alternate supplier. Pricing of the delivery service and CTC charges would be identical to Case 1, except that an additional CTC charge based on the cost of a peaking plant would be assessed.

Example

Registered, on-peak peak demand (kW)	60,000	
Billed demand (kW)	25	
Expected interruptible load (kW)	50,000	Calculated from test year
Total kWh	30,660,000	Assumes 70% load factor, 730 hours
First block kWh	9,000,000	150 * registered, on-peak peak demand
Second block kWh	7,500,000	150 * registered, on-peak peak, but not to exceed 7.5 mkWh
Third block kWh	14,160,000	Total less first and second blocks
Capacity value in 1999 dollars ($/kW-year)	$20.00	PHB projection + reserve + GRT
Capacity value in $/kW-month	$1.67	
Capacity charge in $/kWh	$0.002717	($1.67/kW-month * 50,000 kW)/30,660,000 kWh

Variable distribution charges - PECO			
Demand	$1.790	$/kW-month	
Energy - block 1	$0.009700	$/kWh	
Energy - block 2	$0.005800	$/kWh	
Energy - block 3	$0.001900	$/kWh	
Variable distribution bill			
Demand	$107,400		
Energy - block 1	$87,300		
Energy - block 2	$43,500		
Energy - block 3	$26,904		
Total	*$265,104*		
Average bill	$0.008647	$/kWh	
CTC for on-peak consumption	$0.004071	$/kWh	Includes additional capacity charge

CTC charges - PECO - off-peak consumption			
Demand	$7.63	$/kW-month	
Energy - block 1	$0.041400	$/kWh	
Energy - block 2	$0.024800	$/kWh	
Energy - block 3	$0.008300	$/kWh	
CTC bill - off-peak consumption only			
Demand	$191		
Energy - block 1	$155		
Energy - block 2	$93		
Energy - block 3	$175,568		
Total CTC bill	$176,007		
Average bill	$0.011037	$/kWh	Includes additional capacity charge

Total unbundled bill - on-peak	
Distribution	$0.008647
CTC	$0.004071
Total	$0.012717
Total unbundled bill - off-peak	
Distribution	$0.008647
CTC	$0.011037
Total	$0.019684

FOR ILLUSTRATIVE PURPOSES ONLY

RATE R RESIDENCE SERVICE

AVAILABILITY.

Single-phase Electric Delivery Service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members when such service is supplied through one meter. Electric Delivery Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date must be individually metered for their basic Electric Delivery Service supply. Centrally supplied master metered heating, cooling or water heating service may be provided if such supply will result in energy conservation.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost-sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space is used for the conduct of business by a person residing therein; (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain, stock, dairy, poultry, garden truck, or other agricultural products.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) farms operated principally to sell, prepare, or process products produced by others, or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2, 1969); (e) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37-1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS.

Standard single-phase secondary delivery service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $5.10

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS. (June through September)
4.68¢ per kWh for the first 500 kWh per dwelling unit
5.43¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
4.68¢ per kWh

COMPETITIVE TRANSITION CHARGE:
SUMMER MONTHS. (June through September)
4.89¢ per kWh for the first 500 kWh per dwelling unit
5.67¢ per kWh for additional kWh.

WINTER MONTHS. (October through May)
4.89¢ per kWh

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

SUMMER MONTHS. (June through September)
2.92¢ per kWh for the first 500 kWh per dwelling unit
3.15¢ per kWh for additional kWh.

WINTER MONTHS. (October through May)
2.92¢ per kWh

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION AND TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

PAYMENT TERMS.

Standard.

RATE RT RESIDENCE TIME-OF-USE SERVICE

AVAILABILITY.

Single-phase Electric Delivery Service in the entire territory of the Company to the dwelling and appurtenances of a single private family for the domestic requirements of its members when such service is supplied through one meter. Electric Delivery Service is also available for related farm purposes when such service is supplied through one meter in conjunction with the farmhouse domestic requirements.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other portions of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost-sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling placeof a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space if used for the conduct of business by a person residing therein; (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain, stock, dairy, poultry, garden truck, or other agricultural products.

The term does NOT include service to: (a) Premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) farms operated principally to sell, prepare, or process products produced by others, or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2, 1969); (e) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37-1/2 amperes at 240 volts.

CURRENT CHARACTERISTICS.

Standard single-phase secondary delivery service.

DEFINITION OF PEAK-HOURS.

On-Peak Hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-Peak Hours are defined as the hours other than those specified as on-peak hours.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $10.19

VARIABLE DISTRIBUTION SERVICE CHARGE:
SUMMER MONTHS (June through September)
2.84¢ per off-peak kWh
9.63¢ per on-peak kWh
WINTER MONTHS (October through May)
2.84¢ per off-peak kWh
8.88¢ per on-peak kWh

COMPETITIVE TRANSITION CHARGE:
SUMMER MONTHS. (June through September)
2.50¢ per off-peak kWh
8.46¢ per on-peak kWh.
WINTER MONTHS. (October through May)
2.50¢ per off-peak kWh
7.80¢ per on-peak kWh.

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.
SUMMER MONTHS. (June through September)
1.47¢ per off-peak kWh
4.98¢ per on-peak kWh
WINTER MONTHS. (October through May)
1.47¢ per off-peak kWh
4.60¢ per on-peak kWh

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.
STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

CONTRACT TERM.

Not less than twelve months.

PAYMENT TERMS.

Standard.

RATE R-H RESIDENTIAL HEATING SERVICE

AVAILABILITY.

Single-phase Electric Delivery Service to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for domestic requirements when such service is supplied through one meter and where the dwelling is heated by specified types of electric space heating systems. The systems eligible for this rate are (a) permanently connected electric resistance heaters where such heaters supply all of the heating requirements of the dwelling, (b) heat pump installations where all of the supplementary heating required is supplied by electric resistance heaters, and (c) heat pump installations where all of the supplementary heating required is supplied by non-electric energy sources. All space heating installations must meet Company requirements. This rate schedule is not available for commercial, institutional or industrial establishments.

Wood, solar, wind, water, and biomass systems may be used to supply a portion of the heating requirements in conjunction with service supplied hereunder. Any Customer system of this type that produces electric energy may not be operated concurrently with service supplied by the Company except under written agreement setting forth the conditions of such operation as provided by and in accordance with the provisions of the Auxiliary Service Rider.

Each dwelling unit connected after May 10, 1980 except those dwelling units under construction or under written contract for construction as of that date, must be individually metered.

CURRENT CHARACTERISTICS.

Standard single-phase secondary delivery service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE: $5.10

VARIABLE DISTRIBUTION SERVICE :

SUMMER MONTHS. (June through September)
4.42¢ per kWh for the first 500 kWh per dwelling unit
5.13¢ per kWh for additional kWh.

WINTER MONTHS. (October through May)
4.42¢ for the first 600 kWh per dwelling unit
1.87¢ per kWh for additional kWh.

COMPETITIVE TRANSITION CHARGE:

SUMMER MONTHS. (June through September)
4.95¢ per kWh for the first 500 kWh per dwelling unit
5.75¢ per kWh for additional kWh.

WINTER MONTHS. (October through May)
4.95¢ per kWh for the first 600 kWh per dwelling unit
2.10¢ per kWh for additional kWh.

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generations Suppliers other than PECO Energy.

SUMMER MONTHS. (June through September)
3.12¢ per kWh for the first 500 kWh per dwelling unit
3.38¢ per kWh for additional kWh.

WINTER MONTHS. (October through May)
3.12¢ per kWh for the first 600 kWh per dwelling unit
2.17¢ per kWh for additional kWh.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

COMBINED RESIDENTIAL AND COMMERCIAL SERVICE.

Where a portion of the Electric Delivery Service supplied is used for commercial purposes, the appropriate general service rate is applicable to all service; or, at the option of the Customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

PAYMENT TERMS.

Standard.

CAP RATE

(Experimental Rate - limited to 5000 customers)

AVAILABILITY.

To payment-troubled customers who are currently served under or otherwise qualify for Rate R or Rate RH (does not include multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for this rate and must demonstrate annual household gross income below 150% of the Federal Poverty guidelines.

Customers with annual household gross incomes below 100% of the Federal poverty income guidelines will be eligible for Customer Assistance Program (CAP) Rate I.

Customers with annual household gross incomes between 100% and 150% of the Federal poverty income guidelines will be eligible for Customer Assistance Program (CAP) Rate II.

Certification by various State agencies that a customer is receiving certain government assistance payments may be used where possible to expedite the eligibility process. These payments include (but are not limited to) AFDC, SSI, Food Stamps, PACE and Medicaid. Information available from the Pa. Department of Revenue may also be used where appropriate to expedite the process.

A process will be established to provide verification of eligibility for customers who do not fit the above processes. Asset testing will also be used where necessary and appropriate.

Customers being considered for the CAP Rates will be required to:

* Waive certain privacy rights to enable PECO Energy to effectively conduct the above certification process.
* Apply for and assign to PECO Energy at least one energy assistance grant from the Commonwealth.
* Participate in various energy education and conservation programs facilitated by PECO.

MONTHLY RATE TABLE.

Rate R customers - CAP Rate I

FIXED DISTRIBUTION SERVICE CHARGE:	$5.10
VARIABLE DISTRIBUTION SERVICE CHARGE:	1.97¢ per kWh for the first 500 kWh 4.68¢ per kWh for additional kWh
COMPETITIVE TRANSITION CHARGE:	2.36¢ per kWh for the first 500 kWh 4.89¢ per kWh for additional kWh
ENERGY CHARGE PRICES:	1.41¢ per kWh for the first 500 kWh 2.92¢ per kWh for additional kWh

Rate R customers - CAP Rate II

FIXED DISTRIBUTION SERVICE CHARGE:	$5.10
VARIABLE DISTRIBUTION SERVICE CHARGE:	3.33¢ per kWh for the first 500 kWh 4.68¢ per kWh for additional kWh
COMPETITIVE TRANSITION CHARGE:	3.62¢ per kWh for the first 500 kWh 4.89¢ per kWh for additional kWh
ENERGY CHARGE PRICES:	2.16¢ per kWh for the first 500 kWh 2.92¢ per kWh for additional kWh

CAP RATE -CONTINUED

Rate RH customers - CAP Rate I

FIXED DISTRIBUTION SERVICE CHARGE:	\$5.10
VARIABLE DISTRIBUTION SERVICE:	
SUMMER MONTHS(June through September):	1.97¢ per kWh for the first 500 kWh
	4.68¢ per kWh for additional kWh
WINTER MONTHS (October through May):	1.97¢ per kWh for all kWh
COMPETITIVE TRANSITION CHARGE:	
SUMMER MONTHS(June through September):	2.36¢ per kWh for the first 500 kWh
	4.89¢ per kWh for additional kWh
WINTER MONTHS (October through May):	2.36¢ per kWh for all kWh
ENERGY CHARGE PRICES:	
SUMMER MONTHS(June through September):	1.41¢ per kWh for the first 500 kWh
	2.92¢ per kWh for additional kWh
WINTER MONTHS (October through May):	1.41¢ per kWh for all kWh

Rate RH customers - CAP Rate II

FIXED DISTRIBUTION SERVICE CHARGE:	\$5.10
VARIABLE DISTRIBUTION SERVICE:	
SUMMER MONTHS(June through September):	3.33¢ per kWh for the first 500 kWh
	4.68¢ per kWh for additional kWh
WINTER MONTHS (October through May):	3.33¢ per kWh for the first 500 kWh
	1.97¢ Per KWh for additional kWh
COMPETITIVE TRANSITION CHARGE:	
SUMMER MONTHS(June through September):	3.62¢ per kWh for the first 500 kWh
	4.89¢ per kWh for additional kWh
WINTER MONTHS (October through May):	3.62¢ per kWh for the first 500 kWh
	2.36¢ Per KWh for additional kWh
ENERGY CHARGE PRICES:	
SUMMER MONTHS(June through September):	2.16¢ per kWh for the first 500 kWh
	2.92¢ per kWh for additional kWh
WINTER MONTHS (October through May):	2.16¢ per kWh for all kWh
	1.41¢ per kWh for additional kWh

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

ARREARAGE.

Customers who qualify and are placed on the CAP Rate will have their pre-program arrearage forgiven if they remain current on their CAP bill for six to twelve months. The development of any new arrearage during this period will delay forgiveness.

Customers on the CAP Rate, that develop any new arrearage, will be offered a payment agreement to resolve that arrearage.

RATE OP OFF-PEAK SERVICE

AVAILABILITY.

In conjunction with Rates R, RT, R-H and with residence Electric Delivery Service under Rate GS, for any Customer receiving delivery service at 120/240 volts, 3 wires, or 120/208 volts, 3 wires, for the operation of 240-volt or 208-volt domestic equipment of a type approved by the Company. Any load connected for service under Rate OP may not be connected for service under any other rate during the period that service under Rate OP is interrupted. Service will be interrupted during on-peak periods as established by the Company. This rate is not available when the source of supply is service purchased from a neighboring company under a borderline-purchase agreement.

SPECIAL RULES AND REGULATIONS.

The normal control device furnished by the Company has a limited capacity. The Customer shall notify the Company before connecting any load in addition to an existing water heater. If necessary, the Company will install a control device with a rating of 100 amperes to accommodate the additional 240-volt controlled load. For controlled loads larger than 100 amperes the control device shall be furnished, installed and maintained by the Customer.

Service may be interrupted for a total of not more than 6-1/2 hours per day during scheduled periods which may vary from Customer to Customer.

The Company has a program to replace seven-day clock control devices as they fail with five-day radio-control devices which provide uninterrupted service on Saturdays, Sundays and holidays.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE:	\$4.58 per month.
VARIABLE DISTRIBUTION SERVICE CHARGE:	3.60¢ per kWh
COMPETITIVE TRANSITION CHARGE:	0.00¢ per kWh

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

ENERGY CHARGE:	1.82¢ per kWh

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

PAYMENT TERMS.

Standard.

RATE R-S SOLAR RESIDENCE SERVICE

AVAILABILITY

Single-phase electric service in the entire territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units, whether occupied or not), for the domestic requirements of its members, that has installed solar panels or similar device or devices that are, in PECO Energy's sole judgment, a bona fide technology for use in generating electricity using energy from the Sun, and that will be operated in parallel with the Company's system. The customer's equipment must conform to the installation requirements contained in the Company's published "Requirements For Parallel Operation Of Non-Utility Generation." The Company will modify its distribution and transmission facilities as necessary to interconnect with the Customer at a single point. A customer will be charged for all modifications, additions or retirements made to provide the interconnection, in accordance with the "Requirements for Parallel Operation of Non-Utility Generation". This rate schedule is not available for commercial, institutional or industrial establishments.

The term "residence service" includes service to: (a) the separate dwelling unit in an apartment house or condominium, but not the halls, basement, or other options of such building common to more than one such unit; (b) the premises occupied as the living quarters of five persons or less who unite to establish a common dwelling place for their own personal comfort and convenience on a cost-sharing basis; (c) the premises owned by a church, and primarily designated or set aside for, and actually occupied and used as, the dwelling place of a priest, rabbi, pastor, rector, nun or other functioning Church Divine, and the resident associates; (d) private dwellings in which a portion of the space if used for the conduct of business by a person residing therein; (e) farm purpose uses by an individual employing the natural processes of growth for the production of grain, stock, dairy, poultry, garden truck, or other agricultural products.

The term "residence service" does NOT include service to: (a) premises institutional in character including Clubs, Fraternities, Orphanages or Homes; (b) premises defined as a rooming house or boarding house in the Municipal Code for Cities of the First Class enacted by Act of General Assembly; (c) a premises containing a residence unit but primarily devoted to a professional or other office, studio, or other gainful pursuit; (d) farms operated principally to sell, prepare, or process products produced by others, or farms using air conditioning for climatic control in conjunction with growth processes (except those customers receiving such service as of August 2, 1969); (e) electric furnaces or welding apparatus other than a transformer type "limited input" arc welder with an input not to exceed 37-1/2 amperes at 240 volts.

(Not available when the source of supply is service purchased from a neighboring Company under Rate BLI Borderline Interchange Service.)

METERING/BILLING PROVISIONS.

A customer may select one of the following two billing and metering options:

(a) A ratcheted meter may be installed that records only energy sales to the customer. If the solar panels or other device generate more electricity than the customer uses in any billing month, then the customer will not be charged for any energy usage, but the customer will not be paid by the Company for the excess energy delivered to PECO Energy. No dual metering charge shall apply.

(b) Two meters may be installed. One will measure the energy delivered by the Company that the customer uses, and the other will measure the energy delivered to the Company from the customer that is generated by the customer's solar panels or other qualified device. If, in any billing month, the amount of energy delivered by the Company that the customer uses is greater than the amount of energy the customer delivered to the Company, then the Company will bill the customer for the difference. If, in any billing month, the amount of energy delivered by the Company that the customer uses is less than the amount of energy the customer delivered to the Company, the Company will pay the customer for the excess using the monthly average PJM billing rate. A monthly meter charge shall apply if this billing and metering option is selected. A customer may sell any excess energy to an Electric Generation Supplier other than PECO Energy. However, the customer must pay the appropriate transmission and distribution service charges on this excess energy.

CURRENT CHARACTERISTICS.

Standard single-phase secondary service.

MONTHLY RATE TABLE FOR NET ENERGY USED BY CUSTOMER.

FIXED DISTRIBUTION SERVICE CHARGE: $5.10

DUAL METERING CHARGE: $4.46

VARIABLE DISTRIBUTION SERVICE CHARGE:

SUMMER MONTHS. (June through September)
4.68¢ per kWh for the first 500 kWh per dwelling unit
5.43¢ per kWh for additional kWh.

WINTER MONTHS. (October through May)
4.68¢ per kWh

RATE R-S SOLAR RESIDENCE SERVICE-CONTINUED

COMPETITIVE TRANSITION CHARGE:
SUMMER MONTHS. (June through September)
4.89¢ per kWh for the first 500 kWh per dwelling unit
5.67¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
4.89¢ per kWh

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.
SUMMER MONTHS. (June through September)
2.92¢ per kWh for the first 500 kWh per dwelling unit
3.15¢ per kWh for additional kWh.
WINTER MONTHS. (October through May)
2.92¢ per kWh.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Service Charge and the Dual Service Charge where applicable.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

CONTRACT TERM.
Not less than twelve months.

PAYMENT TERMS.
Standard

RATE-GS GENERAL SERVICE

AVAILABILITY.

Electric Delivery Service through a single metering installation for offices, professional, commercial or industrial establishments, governmental agencies, and other applications outside the scope of the Residence Service rate schedules.

CURRENT CHARACTERISTICS.

Standard single-phase or polyphase secondary delivery service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE:

$ 6.63 for single-phase delivery service without demand measurement, or
$ 8.67 for single-phase delivery service with demand measurement, or
$23.45 for polyphase delivery service.

VARIABLE DISTRIBUTION SERVICE CHARGE:

3.59¢ per kWh for the first 80 hours' use of billing demand
* 1.70¢ per kWh for the next 80 hours' use of the billing demand
1.08¢ per kWh for additional use; except
0.49¢ per kWh over both 400 hours' use of billing demand and 2,000 kWh

COMPETITIVE TRANSITION CHARGE:

11.87¢ per kWh for the first 80 hours' use of billing demand
* 5.62¢ per kWh for the next 80 hours' use of billing demand
3.57¢ per kWh for additional use; except
1.61¢ per kWh over both 400 hours' use of billing demand and 2,000 kWh.

* During October through May this block is eliminated.

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

5.39¢ per kWh for the first 80 hours' use of billing demand
* 3.31¢ per kWh for the next 80 hours' use of billing demand
2.63¢ per kWh for additional use; except .
1.98¢ per kWh over both 400 hours' use of billing demand and 2,000 kWh.

* During October through May this block is eliminated.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate.

DETERMINATION OF DEMAND.

The billing demand will be measured where consumption exceeds 1,100 kilowatt-hours per month for three consecutive months; or where load tests indicate a demand of five or more kilowatts; or where the Customer requests demand measurement. Measured demands will be determined to the nearest 0.1 of a kilowatt but will not be less than 1.2 kilowatts, and will be adjusted for power factor in accordance with the Rules and Regulations.

For those customers with demand measurement, during October through May the billing demand will not be less than 40% of the highest billing demand in the preceding months of June through September, nor less than the minimum value stated in the contract for service. If a measured demand Customer has less than 1,100 monthly kilowatt-hours of use, the monthly billing demand will be the measured demand or the metered monthly kilowatt-hours divided by 175 hours, whichever is less, but not less than 40% of the highest billing demand in the preceding months of June through September, nor less than 1.2 kilowatts.

For those customers without demand measurement, the monthly billing demand will be computed by dividing the metered monthly kilowatt-hours by 175 hours. The computed demand will be determined to the nearest 0.1 of a kilowatt, but will not be less than 1.2 kilowatts.

MINIMUM CHARGE.

The monthly minimum charge for customers without demand measurement will be the Fixed Distribution Service Charge. The monthly minimum charge for customers with demand measurement will be the Fixed Distribution Service Charge, plus a charge of $6.17 per kW of billing demand.

HEATING MODIFICATION.

Wood, solar, wind, water, and biomass systems may be used to supply a portion of the heating requirements in conjunction with service supplied hereunder. Any Customer system of this type that produces electric energy may not be operated concurrently with service supplied by the Company except under written agreement setting forth the conditions of such operation as provided by and in accordance with the provisions of the Auxiliary Service Rider.

RATE-GS GENERAL SERVICE-CONTINUED

METERING.

A. Single Meter.

Applicable where an area is heated solely by permanently connected electric space heating installations (1) acceptable to the Company, (2) sensitive to outdoor temperature and (3) not less than 5 kilowatts. Qualifying electric heating systems are (1) electric resistance coils, (2) electric resistance baseboards, (3) electric boilers and (4) heat pumps with electric back-up.

During October through May the monthly maximum measured demand shall be reduced by one-half of the difference between the peak winter measured demand and the base load demand over the most recent two year billing period. The base load demand will be defined as the lowest measured demand during the period from October to May. During this period, the billing demand shall never be less than 15 kilowatts; except for those customers in service as of February 18, 1971, the billing demand during October through May shall not be less than one-half of the monthly measured demand.

A customer whose demand reduction was calculated under the methods in effect on September 20, 1996, will continue to receive the same reduction until June 1, 1999 unless the current method (described in the preceding paragraph) yields a smaller measured demand for the customer.

A customer who adds new electrical connected heating load will receive the same proportion of forgiven demand to total demand that they currently receive.

This demand modification will only be applicable within 30 days of the date that the customer requests billing under this provision. It shall be the responsibility of the customer to notify the Company of any subsequent changes to its heating equipment or requirements.

B. Separate Meters.

At the option of the Customer, electricity supplying permanently connected space heating installations or heating equipment sensitive to outdoor temperature with a total capacity of not less than 5 kilowatts, which are acceptable to the Company, will be measured apart from the Customer's other requirements for electric service at the premises. Air conditioning equipment of rated electrical capacity up to twice that of the heating equipment also may be supplied through this separate heating circuit.

During October through May the usage of this separate circuit shall be billed at the charges listed below in lieu of the pricing of the basic Monthly Rate Table.

DISTRIBUTION CHARGE:	2.06¢ per kWh
COMPETITIVE TRANSITION CHARGE:	2.31¢ per kWh
ENERGY CHARGE:	1.73¢ per kWh

During June through September the combined usage shall be billed under the price provisions of the basic Monthly Rate Table.

OFF-PEAK THERMAL STORAGE PROVISION.

Off-peak energy may be supplied exclusively for qualifying Thermal Storage applications only in conjunction with this rate schedule when the load supplied is separately metered. This service will be billed separately at the rate of $11.21 per month, plus the charges listed below.

OFF-PEAK ENERGY DURING THE WINTER AND SUMMER MONTHS:

DISTRIBUTION CHARGE:	1.34¢ per kWh
COMPETITIVE TRANSITION CHARGE:	1.51¢ per kWh
ENERGY CHARGE:	1.13¢ per kWh

ON-PEAK ENERGY DURING THE WINTER MONTHS:

DISTRIBUTION CHARGE:	2.06¢ per kWh
COMPETITIVE TRANSITION CHARGE:	2.31¢ per kWh
ENERGY CHARGE:	1.73¢ per kWh

During the summer months, any on-peak demand and energy will contribute to the pricing of the basic Monthly Rate Table. To qualify for this provision, the Customer must submit an engineering study performed by a professional engineer registered in the Commonwealth of Pennsylvania to the Company for technical review and approval. On-peak hours are defined as the hours between 8:00 a.m. and 8:00 p.m., Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 p.m. on Fridays. Off-peak hours are defined as the hours other than those specified as on-peak hours. For Cooling Thermal Storage applications, during the months of June through September, on-peak hours will commence at 10:00 a.m. instead of 8:00 a.m.

RATE-GS GENERAL SERVICE-CONTINUED

SPECIAL PROVISION.

In accordance with Section 1511, Title 66 Public Utilities, a volunteer fire company or a non-profit senior citizen center may, upon application, elect to have its electric service billed at the pricing of Rate R Residential Service, Rate RT Residential Time of Use, Rate R-H Residential Heating Service, or Rate OP Off-Peak Service as appropriate for the application. The execution of a contract for a minimum term of one year will be required.

For the purposes of this provision, the following words and terms shall have the following meanings, unless the context clearly indicates otherwise:

VOLUNTEER FIRE COMPANY - a separately metered service location consisting of a building, sirens, a garage for housing vehicular fire fighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The use of electric service at this location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.
The Customer of record at this service location must be a predominantly volunteer fire company recognized by the local municipality or PEMA as a provider of fire fighting services.

NON-PROFIT SENIOR CITIZEN CENTER - a separately metered service location consisting of a facility for the use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided.
The Customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) as non-profit and recognized by the Pennsylvania Department of Aging as an operator of a senior citizen center.

PAYMENT TERMS.

Standard.

RATE-PD PRIMARY-DISTRIBUTION POWER

AVAILABILITY.
Untransformed Electric Delivery Service from the primary supply lines of the Company's distribution system where the Customer installs, owns, and maintains any transforming, switching and other receiving equipment required. However, standard primary delivery service is not available in areas where the distribution voltage has been changed to either 13 kV or 33 kV unless the Customer was served with standard primary delivery service prior to the conversion of the area to either 13 kV or 33 kV. This rate is available only for service locations served on this rate on July 6, 1987 as long as the original primary service has not been removed. PECO may refuse to increase the load supplied to a customer served under this rate when, in PECO's sole judgment, any transmission or distribution capacity limitations exist. If a customer changes the billing rate of a location being served on this rate, PECO may refuse to change that location back to Rate PD when, in PECO's sole judgment, any transmission or distribution capacity limitations exist.

CURRENT CHARACTERISTICS.
Standard primary delivery service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE:	\$275.28
VARIABLE DISTRIBUTION SERVICE CHARGE:	\$1.84 per kW of billing demand 1.65¢ per kWh of the first 150 hours' use of billing demand 0.99¢ per kWh of the first next 150 hours' use of billing demand 0.33¢ per kWh for additional use.
COMPETITIVE TRANSITION CHARGE:	\$5.15 per kW of billing demand 4.63¢ per kWh of the first 150 hours' use of billing demand 2.76¢ per kWh for the next 150 hours' use of billing demand 0.93¢ per kWh for additional use.

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

\$1.69 per kW of billing demand
2.99 per kWh of the first 150 hours' use of billing demand
2.38¢ per kWh for the next 150 hours' use of billing demand
1.78¢ per kWh for additional use.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

MINIMUM CHARGE.
The monthly minimum charge shall be the Fixed Distribution Service Charge, plus the Variable Distribution Charge for the monthly billing demand.

PAYMENT TERMS.
Standard.

RATE-HT HIGH-TENSION POWER

AVAILABILITY.
Untransformed Electric Delivery Service from the Company's standard high-tension lines, where the Customer installs, owns, and maintains, any transforming, switching and other receiving equipment required.

CURRENT CHARACTERISTICS.
Standard high-tension delivery service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $286.86

VARIABLE DISTRIBUTION SERVICE CHARGE: $1.79 per kW of billing demand
0.97¢ per kWh of the first 150 hours' use of billing demand
0.58¢ per kWh of the first 150 hours' use of billing demand, but not more than 7,500,000 kwh
0.19¢ per kWh for additional use.

COMPETITIVE TRANSITION CHARGE:
$7.63 per kW of billing demand
4.15¢ per kWh for the first 150 hours' use of billing demand
2.48¢ per kWh for the next 150 hours' use of billing demand, but not more than 7,500,000 kwh
0.83 per kWh for additional use.

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.
$2.50 per kW of billing demand
2.72¢ per kWh for the first 150 hours' use of billing demand
2.17¢ per kWh for the next 150 hours' use of billing demand, but not more than 7,500,000 kwh
1.63¢ per kWh for additional use.

TIME-OF-USE ADJUSTMENT:
Customers with measured demand of 2,000 kW or greater will be given a credit for energy use during off-peak hours and will be subject to an additional charge for energy use during on-peak hours. On-peak hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-peak hours are defined as the hours other than those specified as on-peak hours. The credits and charges are as follows:

	Summer Months (June through September)	Winter Months (October through May)
Off-peak credit...........	0.21¢ per kWh	0.21¢ per kWh
On-peak charge..........	0.57¢ per kWh	0.22¢ per kWh

HIGH VOLTAGE DISCOUNT:
For customers supplied at 33,000 volts: 7¢ per kW of measured demand.
For customers supplied at 69,000 volts: 30¢ per kW for first 10,000 kW of measured demand.
For customers supplied over 69,000 volts: 30¢ per kW for first 100,000 kW of measured demand.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

DETERMINATION OF BILLING DEMAND.
The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 25 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

DELIVERY POINTS.
Where the load of a Customer located on single or contiguous premises becomes greater than the capacity of the standard circuit or circuits established by the Company to supply the Customer, an additional separate delivery point may be established for such premises upon the written request of the Customer and billing continued as if the service were being delivered and metered at a single point, provided such multi-point delivery is not disadvantageous to the Company.

MINIMUM CHARGE.
The monthly minimum charge shall be the Variable Distribution Service Charge, plus the capacity charge for the monthly billing demand, less the supply voltage discount where applicable.

PAYMENT TERMS.
Standard.

RATE SL-P STREET LIGHTING IN CITY OF PHILADELPHIA

AVAILABILITY.

Only to a governmental agency, municipal, state or federal, for outdoor lighting of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder, for the safety and convenience of the public within the City of Philadelphia by incandescent filament, mercury-vapor, fluorescent or sodium-vapor lamps of standard sizes and types approved by the Company where the Customer installs, owns and maintains all Utilization Facilities as hereinafter defined. Service will be supplied under this rate for street Lighting Units supported in a conventional manner such as on poles, posts, brackets or hangers, and under conditions of installation and supply acceptable to the Company.

CHARACTERISTICS OF SUPPLY.

Service under this rate will be from series 6.6 ampere circuits or from standard single-phase secondary circuits, as specified by the Company, except that, where conditions require, or where existing standard secondary circuits are not available, the Company at its option may supply service from nonstandard secondary circuits, providing nominally 240 volts.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE:

For Lighting Units in service as of the fifteenth day of the month.

- \$ 8.64 per Lighting Unit supplied from standard secondary (aerial or underground) circuits where the Customer owns the individual control for such Lighting Unit.
- \$ 9.24 per Lighting Unit supplied from aerial (series or secondary) circuits where the Company provides group controls.
- \$12.89 per Lighting Unit supplied from underground (series or secondary) circuits where the Company provides group controls.

VARIABLE DISTRIBUTION SERVICE CHARGE: 0.062¢ per Watt
0.411¢ per kWh

COMPETITIVE TRANSITION CHARGE: 0.135¢ per Watt
0.888¢ per kWh

ENERGY CHARGE PRICE: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

0.150¢ per Watt
2.39¢ per kWh

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

LIGHTING UNIT

A Lighting Unit shall comprise each lighting installation which is separately connected to a delivery point on the Company's series or secondary circuit.

DETERMINATION OF BILLING DEMAND.

The wattage, expressed to the nearest tenth of a watt, of a Lighting Unit shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of wattages of all Lighting Units in service as of the fifteenth day of a month shall constitute the billing demand for the month.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Lighting Unit shall be computed to the nearest kilowatt-hour as the product of one-thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules approved by the authorized representatives of the Customer and the Company. The aggregate of the kilowatt-hours thus computed for all Lighting Units in service as of the fifteenth day of a month shall constitute the energy billed for the month.

(Continued)

RATE SL-P STREET LIGHTING IN CITY OF PHILADELPHIA - CONTINUED

TERMS AND CONDITIONS.

1. Ownership and Type of Control Facilities.
   a. Lighting Units Supplied from Standard Secondary Circuits: Customer shall provide, own and maintain for each of such Lighting Units, the individual control of a type approved by the Company except that, at the option of the Customer, the Company will continue to provide group control facilities presently in service.
   b. Lighting Units Supplied from Series and from Nonstandard Secondary Circuits: Company will provide, own and maintain group control facilities.

2. Ownership of Utilization Facilities.
   a. Lighting Units Supplied from Aerial Circuits: Customer shall provide, own and maintain the Utilization Facilities comprising the brackets, hangers, luminaries, lamps, ballasts, transformers, individual controls (where used) and other components required for the operation of such Lighting Units, conductors, molding and supporting insulators between the map receptacles and line wires of the Company's distribution facilities.

      Company shall provide the supporting pole or post for such aerially supplied Lighting Unit and will issue authorization to permit the Customer to install thereon the said Utilization Facilities.

   b. Lighting Units Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities comprising the supporting pole or post, foundation with 90-degree pipe bend, brackets or hangers, luminaries, lamps, ballasts, transformers, individual controls (where used) and other components required for the operation of such Lighting Units, conductors and conduits from the lamp receptacles to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a delivery point designated by the Company on its secondary voltage circuit, and shall assume all costs of installing such Utilization Facilities.

      Where vertical extensions are required on foreign-owned posts for the support of such underground supplied Lighting Units, the extension shall be provided and owned by the Customer. Rentals incurred on such foreign-owned posts shall be the responsibility of the Customer.

      Except as provided in 5 hereof, the Company shall own conduit from the distribution circuit to the 90-degree pipe bend, shall own conductors from its distribution system to the designated delivery point or the sidewalk level as specified in 2b, and shall provide sufficient length of conductors for splicing at the designated delivery point or in the post base where sidewalk level access is provided. Where a splicing chamber is provided in the post base, the Customer shall provide space for any relays or similar devices required for the operation on the street lighting circuit.

3. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

4. Power Factor. The Utilization Facilities provided by the Customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

5. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment, including group control facilities where required, installed at the cost and expense of the Company and owned and controlled by it, except that in locations (such as bridges, overpasses, underpasses and limited access highways) where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control, the Customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

RATE SL-P STREET LIGHTING IN CITY OF PHILADELPHIA - CONTINUED

6. Connection of Lighting Units. For new Lighting Units, relocated Lighting Units and for any modernization or maintenance work involving connections to the Company's distribution circuits. In accordance with the provisions of 2, the Customer shall provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit, or at the splicing chamber in the post base (where provided), or at the nearest available manhole, handhole or splice box (where such splicing chamber is not provided). In the latter case, the Customer will bill the Company for the cost of the conductors from the sidewalk level to the manhole, handhole or splice box. All work done by the Customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

7. Location and Type of Installation. The prices of the rate apply to street lighting service under conditions named herein at locations designated by the properly authorized representatives of the Customer.

8. Service. Lighting service will be operated on all-night, every-night lighting schedules, to be approved by the authorized representatives of the Customer and the Company, under which lights normally are turned on after sunset and off before sunrise. Extended lighting service during all daylight hours will be supplied for lamps specified by the Customer.

9. Change in Size of Type of Lighting Units. Written notice of any planned change in size or type of any components of Lighting Units by locations shall be furnished by the Customer to the Company or less than 10 days prior to the effective date of such change. The Customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings of Lighting Units used.

10. Service Maintenance. Upon receipt of report of Lighting Unit or Units not burning, the Company will determine the cause of failure and will restore service on street lighting or distribution circuit and control equipment, disconnecting if necessary any faulty Lighting Units from the circuit. Customer will make necessary repairs between the lamp receptacle of the faulty Lighting Unit or Units and the point of connection to the Company's street lighting or distribution circuit. In the event the fault is located in the Company owned facilities, the Customer will bill the Company for this portion of the replace facilities.

11. Authorization and Protection. The Customer shall, to the extent of ability, furnish any requisite authority for the requisite authority for the erection and maintenance of poles wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the light system.

12. Additional Lighting. Lighting service for additional lamps installed by the Customer will be supplied by the Company upon written notice from the Customer specifying the locations of the installations unless the proposed additional lighting makes the investment or cost of providing distribution equipment excessive. In which case a portion of the investment or cost shall be borne by the Customer subject to agreement between the Customer and the Company.

13. Relocation of Lighting Units. Where a pole is replaced by the Company at its own option, it shall be the Customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

14. Outage Allowance (Applicable only to customers who purchase their electric energy from PECO Energy). Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service and the Customer will use reasonable diligence to protect the lighting system. In lieu of determination of the actual hours of Lighting Unit outages resulting from a failure of any light to burn for any reason, a deduction of 0.20% of the monthly capacity and energy charges will be made on the monthly bill. Company shall not be liable for service interruptions as a result of the Customer's failure to protect the lighting system, or as a result of riot, fire, storm, flood, interference by civil or military authorities or any other cause beyond its control.

TERM OF CONTRACT.
The initial contract term for each lighting unit shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

RATE SL-E STREET LIGHTING CUSTOMER-OWNED FACILITIES

AVAILABILITY.

To any governmental agency outside of the City of Philadelphia for outdoor lighting of streets, highways, bridges, parks or similar places, including directional highway signs at locations where other outdoor lighting service is established hereunder for the safety and convenience of the public where all of the utilization facilities, as defined in Terms and Conditions in this rate schedule, are installed, owned and maintained by a governmental agency.

This rate is also available to community associations of residential property owners both inside and outside the City of Philadelphia for the lighting of streets that are not dedicated. This rate is not available to commercial or industrial customers. All facilities and their installation shall be approved by the Company.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE:	$10.01
VARIABLE DISTRIBUTION SERVICE CHARGE:	0.212¢ per Watt 0.230 ¢ per kWh
COMPETITIVE TRANSITION CHARGE:	*0.018 ¢ per kWh*

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

1.461¢ per kWh

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

SERVICE LOCATION.

A service location shall comprise each lighting installation and must be separately connected to a delivery point on the Company's secondary circuit.

DETERMINATION OF BILLING DEMAND.

The wattage, expressed to the nearest tenth of a watt, of a Service Location shall be composed of manufacturer's rating of its lamps, ballasts, transformers, individual controls and other load components required for its operation. The aggregate of wattages of all Service Locations in service shall constitute the billing demand for the month.

DETERMINATION OF ENERGY BILLED.

The energy use for a month of a Service Location shall be computed to the nearest kilowatt-hour as the product of one-thousandth of its wattage and the effective hours of use of such wattage during the calendar month under the established operation schedules as set forth under Terms and Conditions, Paragraph 6 Service. The aggregate of the kilowatt-hours thus computed for all Active Service Locations shall constitute the energy billed for the month.

TERMS AND CONDITIONS.

1. Ownership of Utilization Facilities.
   a. Service Locations Supplied from Aerial Circuits: Customer shall provide, own and maintain the Utilization Facilities comprising the brackets, hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors, molding and supporting insulators between the lamp receptacles and line wires of the Company's distribution facilities and any other components as required for the operation of each Service Location.
   The Company shall provide the supporting pole or post for such aerially supplied Service Location and will issue authorization to permit the Customer to install thereon the said Utilization Facilities.
   b. Service Locations Supplied from Underground Circuits: Customer shall provide, own and maintain the Utilization Facilities comprising the supporting pole or post, foundation with 90-degree pipe bend, brackets or hangers, luminaries, lamps, ballasts, transformers, individual controls, conductors and conduits from the lamp receptacles to sidewalk level, or in special cases, such as Federally and State financed limited access highways, to a delivery point designated by the Company on its secondary voltage circuit, and shall assume all costs of installing such utilization facilities.

Except as provided in Paragraph 4 Supply Facilities, the Company shall own conduit from the distribution circuit to the 90-degree pipe bend, shall own conductors from its distribution system to the designated delivery point and shall provide sufficient length of conductors for splicing at the designated delivery point or in the post base where sidewalk level access is provided.

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RATE SL-E STREET LIGHTING CUSTOMER-OWNED FACILITIES - CONTINUED

2. Standards of Construction for Utilization Facilities. Customer construction shall meet the Company's standards which are based upon the National Electrical Safety Code. Designs of proposed construction deviating from such standards shall be submitted to the Company for approval before proceeding with any work.

3. Power Factor. The Utilization Facilities provided by the Customer shall be of such a nature as to maintain the power factor of each Lighting Unit at not less than 85%.

4. Supply Facilities. Lighting service shall be supplied from distribution facilities and equipment installed, owned and maintained by the Company. A Customer contribution for new, additional or relocated lighting service may be required as described in Paragraph 10. Where Company ownership of conduit, manholes or vaults may not be practical for reasons beyond its control (such as bridges, overpasses, underpasses and limited access highways), the Customer shall make available at no expense to the Company, space for the Company's distribution facilities required in rendering service under this rate.

5. Connection of Service Location. For new, additional or relocated Service Locations and for any modernization or maintenance work involving connections to the Company's distribution circuits, the Customer will provide sufficient length of conductors to permit the Company to make taps at the top of the pole for aerial circuits, or for splices to underground circuits at the designated delivery point on the Company's secondary voltage circuit. All work done by the Customer that may involve Company street lighting, control, and other distribution circuits shall be performed under Company permit and blocking procedures.

6. Service. Lighting service will be operated on all-night, every-night lighting schedules, under which lights normally are turned on after sunset and off before sunrise with approximately 4,100 annual operating hours. Extended lighting service during all daylight hours will be supplied for lamps specified by the Customer.

7. Change in Size and Type of Service Locations. Written notice of any planned change in size or type of any components of Service Locations shall be furnished by the Customer to the Company not less than 10 days prior to the effective date of such change. The Customer shall be responsible for notification to the Company of any changes made in manufacturer's wattage ratings at any Service Location.

8. Service Maintenance. Upon receipt of report of a Service Location not receiving power, the Company will determine the cause of power failure and will restore service to the distribution circuit and control equipment, disconnecting, if necessary, any faulty Service Location from the circuit. Customer will make necessary repairs between the lamp receptacle of the faulty utilization facilities and the point of connection to the Company's distribution circuit. In the event the fault is located in the Company owned facilities, the Customer will bill the Company for this portion of the replaced facilities.

9. Authorization and Protection. The Customer shall, to the extent of one's ability, furnish any requisite authority for the erection and maintenance of poles, wires, fixtures and other equipment necessary to operate the lights at the locations and under the conditions designated, and shall protect the Company from malicious damage to the lighting system.

10. New, Additional or Relocated Lighting. The total costs to provide lighting service for new, additional or relocated lamps installed by the Customer shall be subject to a revenue test. If the costs exceed the estimated revenue for four years less all fuel cost, a Customer contribution for all excess costs will be required.

11. Relocation of Service Locations. Where a pole is replaced by the Company at its own option, it shall be the Customer's responsibility to have the Utilization Facilities transferred from the old to the new pole.

TERM OF CONTRACT.
The initial contract term for each service location shall be for at least one year.

PAYMENT TERMS.
Bills will be rendered monthly.

RATE TL TRAFFIC LIGHTING SERVICE

AVAILABILITY.
To any municipality using the Company's standard delivery service for electric traffic signal lights installed, owned and maintained by the municipality.

CURRENT CHARACTERISTICS.
Standard single-phase secondary delivery service.

RATE TABLE.

VARIABLE DISTRIBUTION SERVICE CHARGE: 4.57¢ per kWh

COMPETITIVE TRANSITION CHARGE: 4.01¢ per kWh

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.
2.36¢ per kWh

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rate.

SPECIAL RULES AND REGULATIONS.
The use of energy will be estimated by the Company on the basis of the size of lamps and controlling apparatus and the burning-hours. The Customer shall immediately notify the Company whenever any change is made in the equipment or the burning-hours, so that the Company may forthwith revise its estimate of the energy used.

The Company shall not be liable for damage to person or property arising, accruing or resulting from the attachment of the signal equipment to its poles, wires, or fixtures.

MINIMUM CHARGE.
$3.56 per month per signal light.

TERM OF CONTRACT.
The initial contract term for each signal light installation shall be for at least one year.

PAYMENT TERMS.
Standard.

RATE EP ELECTRIC PROPULSION

AVAILABILITY.

This rate is available only to the National Rail Passenger Corporation (AMTRAK) and to the Southeastern Pennsylvania Transportation Authority (SEPTA) for untransformed Electric Delivery Service from the Company's standard high-tension lines, where the Customer installs, owns, and maintains any transforming, switching and other receiving equipment required and where the service is supplied for the operation of electrified transit and railroad systems and appurtenances.

CURRENT CHARACTERISTICS.

Standard sixty hertz (60 Hz) high-tension delivery service.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION SERVICE CHARGE: $1,243.85 per delivery point

VARIABLE DISTRIBUTION SERVICE CHARGE: $3.14 per kW of billing demand
0.26¢ per kWh

COMPETITIVE TRANSITION CHARGE: $9.31 per kW of billing demand
0.77¢ per kWh

ENERGY CHARGE PRICE: The following energy charge will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

$2.98 per kW of billing demand
1.62¢ per kWh

TIME-OF-USE ADJUSTMENT:

There will be a credit for energy use during off-peak hours and an additional charge for energy use during on-peak hours. On-peak hours are defined as the hours between 8:00 am and 8:00 pm, Eastern Standard Time or Daylight Saving Time, whichever is in common use, daily except Saturdays, Sundays and holidays; except that the on-peak hours will end at 4:00 pm on Fridays. Off-peak hours are defined as the hours other than those specified as on-peak hours. The credits and charges are as follows:

	Summer Months (June through September)	Winter Months October through May)
Off-peak credit	0.21¢ per kWh	0.21¢ per kWh
On-peak charge	0.57¢ per kWh	0.22¢ per kWh

HIGH VOLTAGE DISCOUNT:

For delivery points supplied at 33,000 volts: 7¢ per kW
For delivery points supplied at 69,000 volts: 30¢ per kW for first 10,000 kW of measured demand.
For delivery points supplied over 69,000 volts: 30¢ per kW for first 100,000 kW of measured demand.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT applies to this rate.

DETERMINATION OF BILLING DEMAND.

The billing demand will be computed to the nearest kilowatt and will never be less than the measured demand, adjusted for power factor in accordance with the Rules and Regulations, nor less than 5,000 kilowatts. Additionally, during the eight months of October through May the billing demand will not be less than 40% of the maximum demand specified in the contract nor less than 80% of the highest billing demand in the preceding months of June through September.

CONJUNCTIVE BILLING OF MULTIPLE DELIVERY POINTS

If the load of a Customer located at a delivery point becomes greater than the capacity of the circuits established by the Company to supply the Customer at that delivery point, upon the written request of the Customer, the Company will establish a new delivery point and bill the Customer as if it were delivering and metering the two services at a single point, as long as installation of the new service is, in the Company's opinion, less costly for the Company than upgrading the service to the first delivery point.

STANDARD RIDERS - CONTINUED

Applicable to rates as indicated in Applicability Index of Riders

ALLEY LIGHTING RIDER

APPLICABILITY. To multiple, unmetered lighting delivery service supplied the City of Philadelphia to operate incandescent lamps and appurtenances installed, owned and maintained by the City, which assumes the cost involved in making the connections to the Company's facilities.

SERVICE DEFINED. All-night outdoor lighting of alleys and courts by incandescent lights installed on poles or supports supplied by the City.

NOTICE TO COMPANY. The City shall give advance notice to the Company of all proposed new installations or of the replacement or reconstruction of existing installations. The City shall advise the Company as to each new installation or change in the equipment or connected load of an existing installation, including any change in burning hours and the date on which such new or changed operation took effect.

MONTHLY RATE TABLE.

VARIABLE DISTRIBUTION SERVICE CHARGE: 5.09¢ per kWh

COMPETITIVE TRANSITION CHARGE: 4.47¢ per kWh

ENERGY CHARGE PRICES: The following energy charges will apply to customers that purchase their electric energy from PECO Energy and not applicable to customers who purchase energy from Electric Generation Suppliers other than PECO Energy.

2.63¢ per kWh

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE, SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rider.

PLAN OF MONTHLY BILLING. Bills may be rendered in equal monthly installments, computed from the calculated annual use of energy, adjusted each month to give effect to any new or changed rate of annual use, by reason of changes in the City's installation, with charge or credit for fractional parts of the month during which a change occurred.

LIABILITY PROVISION. The Company shall not be liable for damage, or for claims for damage, to persons or property, arising, accruing or resulting from, installation, location or use of lamps, wires, fixtures and appurtenances; or resulting from failure of any light, or lights, to burn for any cause whatsoever.

TERM OF CONTRACT. The initial contract term for each lighting unit shall be for at least one year.

STANDARD RIDERS - CONTINUED

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER

APPLICABILITY. Service to customers, including but not limited to qualifying facilities of small power producers and cogenerators as defined in the Public Utility Regulatory Policies Act, whose electrical requirements are partially or wholly provided by facilities not owned by the Company and when such facilities operate in parallel with the Company, will be supplied only under the provisions of this rider.

EXTENT OF SUPPLY. The maximum firm supply available from the Company will be defined by contract except for customers served on Rates R, R-H and GS-without demand measurement.

PARALLEL OPERATION. The Customer shall not commence initial operation of any other source of supply in parallel with the Company's service until written permission is given by the Company for such parallel operation. Written permission is not necessary for reestablishing parallel operation, but the Customer shall notify the Company when resuming any parallel operation after an outage. The Company shall have the right to inspect the Customer's installation in accordance with Tariff Rule 9.3.

TYPE OF SUPPLY. The following types of power supply are available:

Supplementary Power supply is available to add to alternative generating capacity whether or not owned by the Customer. All power provided pursuant to this Rider shall be Supplementary Power unless it is provided within the definition of Back-up Power or Maintenance Power.

Back-Up Power supply is available to replace alternative generating capacity whether or not owned by the Customer during a forced outage of all or part of such generating capacity. Back-Up Power (firm and interruptible) shall be limited to 15% of the hours in any twelve-month period after which any additional power utilized shall be billed at Supplementary Power. The Customer must orally notify the Company immediately when Back-Up Power is used, and within one business day after the forced outage giving rise to the need for Back-Up Power, shall furnish the Company with a letter verifying the outage, specifying the time at which the outage commenced, the reason for the outage, and providing the best estimate possible of its duration. Oral and written notice shall also be provided to the Company within one business day following the conclusion of the forced outage. The Company may require verification of the cause of such forced outage. The foregoing 15% limitation on the number of hours in which Back-Up Power may be received shall not apply during the following periods, nor shall such periods be taken into account in determining whether Back-Up Power use in any subsequent period has exceeded such limitation: (a) in the case of an alternative generating facility with rated capacity of 1 MW or less, the three-month period commencing on the date such facility is first operated in parallel with the Company's service; and (b) in the case ofan alternative generating facility with rated capacity in excess of 1 MW; the six-month period commencing on the date such facility is first operated in parallel with the Company's service.

Maintenance Power is available to replace alternative generating capacity whether or not owned by the Customer during periods of scheduled maintenance. Maintenance Power will be supplied on a scheduled basis in one of the following manners:

(a) Upon mutual agreement, at any time.
(b) Upon at least 60 days written notice and not more than 180 days written notice by the Customer, the Company will advise the Customer, within 30 days of the receipt of the request, of the availability of the requested Maintenance Power, for power required for a period of more than 48 hours duration. If the power is unavailable during the requested period, the Company will provide Maintenance Power within 30 days prior or subsequent to the beginning of the requested period and will so inform the Customer.
(c) Upon 360 days written notice by the Customer, the Company will provide Maintenance Power during the requested period, unless the cumulative total of all such power requested during such time period will exceed 5% of the Company's operable generating capacity, in which case the provisions of (b) above will apply.
(d) For Maintenance Power required for a period of 48 hours or less duration, at a demand of 50 MW or less, the Company will supply such power on a least 30 days written notice.
(e) The Company in its sole discretion may refuse to schedule firm Maintenance Power during the months of June through September except that Maintenance Power as defined in (d) above will be made available during June through September as long as it can be scheduled during off-peak hours.

STANDARD RIDERS - CONTINUED

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER - CONTINUED

Maintenance Power will be limited to no more than 120 days in any twelve-month period, and no more than 60 consecutive days, after which any additional power utilized shall be billed as Supplementary Power. The foregoing limitations on the number of days in which Maintenance Power may be received shall not apply during the following periods, nor shall such periods be taken into account in determining whether Maintenance Power use in any subsequent period has exceeded such limitations: (a) in the case of an alternative generating facility with rated capacity of 1 MW or less, the three-month period commencing on the date such facility is first operated in parallel with the Company's service; and (b) in the case of an alternative generating facility with rated capacity in excess of 1 MW, the six-month period commencing on the date such facility is first operated in parallel with the Company's service. The supply of Maintenance Power will be terminated when generating capacity from which the Customer is supplied is returned to operation as indicated by the recorded demands on the Company's metering equipment, or upon notification to the Company by the Customer, or upon the expiration of the maximum maintenance period, whichever occurs first.

INTERRUPTIBLE POWER FOR BACK-UP OR MAINTENANCE. Customers with a minimum of 1,000 KW of interruptible Back-Up or Maintenance Power may contract for interruptible supply. When a Customer contracts for interruptible supply,
such supply shall be interrupted when, in the sole judgment of the Company, any production, transmission or distribution capacity limitations exist. The Customer shall interrupt such load after a minimum of sixtyminutes prior notice by the Company. When a Customer is notified by the Company to interrupt service and the Customer fails to interrupt, a penalty of $24 per kilowatt shall be applicable to each kilowatt of demand that has not been interrupted.

RATE AND BILLING.
All monthly bills for service on this rider shall include one application of the Fixed Distribution Service Charge of the applicable rate. All other Demand and Energy Charges of the applicable rate shall be modified as set forth below.

SUPPLEMENTARY POWER.
Billing shall be under the provisions of the applicable rate and riders.

FIRM BACK-UP POWER.
Charges are per kilowatt of demand specified in the contract for back-up supply. This charge shall include energy use equal in cost to the total monthly demand charge.

	Distribution Charge:	$0.42 per kW
	Competitive Transition Charge:	$1.79 per kW
	Energy Charge:	$0.59 per kW
For service billed at:		
High Tension Voltage:		
	Distribution Charge:	1.01 per kWh
	Competitive Transition Charge:	4.02¢ per kWh
	Energy Charge:	2.36¢ per kWh
Primary Voltage:		
	Distribution Charge:	1.87¢ per kWh
	Competitive Transition Charge:	4.35¢ per kWh
	Energy Charge:	3.19¢ per kWh
Secondary Voltage:		
	Distribution Charge:	2.04¢ per kWh
	Competitive Transition Charge:	6.21¢ per kWh
	Energy Charge:	3.52¢ per kWh

INTERRUPTIBLE BACK-UP POWER. (Interruptible back-up power is available only to customers who purchase their electric energy from PECO Energy.)
Demand Charge: None.
Energy Charge for service billed at:

	High Tension Voltage:	2.74¢ per kWh
	Primary Voltage:	3.14¢ per kWh
	Secondary Voltage:	4.25¢ per kWh

STANDARD RIDERS - CONTINUED

Applicable to rates as indicated in Applicability Index of Riders

AUXILIARY SERVICE RIDER - CONTINUED

FIRM MAINTENANCE POWER.

June through September: Same as Supplementary Power.
October through May: Same as Interruptible Back-Up Power.

INTERRUPTIBLE MAINTENANCE POWER. (Interruptible maintenance power is available only to customers who purchase their electric energy from PECO Energy).
Same as Interruptible Back-Up Power.

STATE TAX ADJUSTMENT CLAUSE, INTANGIBLE TRANSITION CHARGE SECURITIZATION RATE REDUCTION and TRANSITION BOND EXPENSE ADJUSTMENT apply to this rider.

BILLING. Bills rendered to the Customer shall distinguish between the Customer's use of Supplementary Power, Back-Up Power and Maintenance Power. In the event that the Customer receives two or more types of supply during the billing period, the billing characteristics shall be determined as follows:

(a) the billing demand will be the maximum measured demand, adjusted for power factor in accordance with the Rules and Regulations, occurring during any unscheduled outage period of the month less the Supplementary Power billing demand; less the Scheduled Maintenance Power Capacity for the month if one or both of these additional services are provided at the time of maximum measured demand.

(b) the energy use billed as Back-Up and/or Maintenance Power shall be one-half of the sum of the Back-Up and/or Maintenance half-hour demands;

(c) the total energy use, less the energy use determined in (b) shall be the energy use for Supplementary Power;

(d) if only one type of power is used, billing shall be in accordance with the total recorded demand and energy use.

DISTRIBUTION FACILITIES. Any investment in additions or changes to the Company's distribution facilities required to provide auxiliary service (in excess of such investments normally made by the Company to provide equivalent service to the Customer) will be paid by the Customer before the interconnection of Company and Customer facilities. In addition, when necessary, the cost of communications equipment, such as telemetering or telephone, will be paid by the Customer.

POINTS OF SERVICE. The Company shall not be required to serve customers receiving electric power from alternative generating facilities at multiple points of service that were used prior to the parallel operation of the alternative generating facilities if after the introduction of these alternative generating facilities the multiple points of service are disadvantageous to the Company or pose unacceptable risks.

DATA. The Customer shall furnish such detailed load data and data on forced outage rates as the Company shall, from time to time, require, together with such supporting documentation as the Company shall request, in order for the Company to collect data and prepare such reports as may be required by the Pennsylvania Public Utility Commission.

TERM. Annual, except where otherwise specified by the firm rate.

R00973953

PECO STATEMENT NO. 4-R

Phila 10/14,15,16/97
E. Holbert

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

JOHN F. BUSTARD

Providing An Update Of PECO's Market Value Analyses; Comparing Various Market Value Projections; Identifying Areas Of Agreement Among Analyses; Critiquing PAIEUG And OCA Analyses; Responding To Criticisms Regarding The EDS Analysis; And Responding To Comments Regarding Integrated T&D Planning And Energy Conservation Programs.

July 18, 1997

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is John F. Bustard. My business address is PECO Energy Company ("PECO"), 2301 Market Street, Philadelphia, PA 19103.

Q. Have you previously participated in this proceeding?

A. Yes. I submitted direct testimony (PECO Statement No. 4) and various supporting exhibits (Exhibits JFB-1 through JFB-10) with PECO's April 1, 1997 filing of its restructuring plan. A statement of my qualifications is contained in my direct testimony.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony I will first provide a general overview of material modifications to the three PECO market value analyses made since the initial filing to reflect more current fuel price projections, to incorporate publicly available information regarding heat rates, and to respond to some valid criticisms and proposals of the intervenors. I will then provide an updated market value projection. Next, I will compare the various projections of market value which have been submitted to date for PECO's generation region. I will then identify facets of the market value analyses on which there appears to be general agreement among the parties. I will then critique the modeling methodology and input assumptions of the market value testimony and models submitted by the

Philadelphia Area Industrial Energy Users Group ("PAIEUG"), through witness Randall Falkenberg, and the Office of Consumer Advocate ("OCA"), through witnesses Richard LaCapra and Douglas Smith. Next, I will address, as follows, specific proposals and criticisms of intervenors with respect to the EDS market value analysis:

- validity of heat rates;
- validity of fuel price assumptions; and
- appropriateness of the markets modeled.

In general, I will address only those criticisms directed specifically at the EDS or PROMOD IV models and/or my testimony. Criticisms directed to more than one model will be addressed in the rebuttal testimony of Dr. Hieronymus (PHB model) and Mr. Rose (ICF model). Finally, I will address comments by the Environmentalists concerning integrated transmission and distribution ("T&D") planning and energy conservation programs.

Q. **Please summarize the major points you will make in your testimony.**

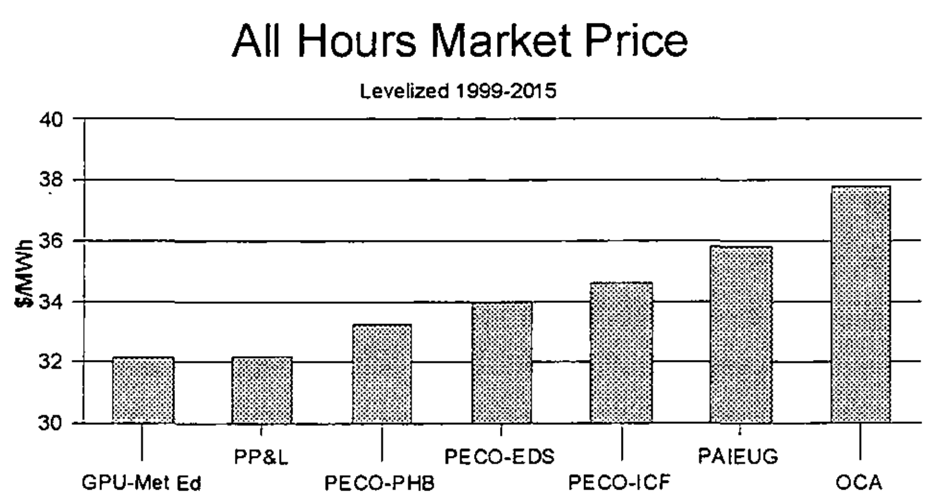
A. First, PECO has updated its three market value projections and quantified the effect of using EIA fuel price projections. In doing so, PECO has attempted to eliminate as much controversy as possible from its market value projections. As shown below, the result of these updates, which include changes suggested by the intervenors, is a *decrease* in PECO's market value projection from $2.862 billion in the initial filing to $2.303 billion presently.

Net Present Value of PECO Generation
$ Million NPV 1999

	PECO-PHB
Baseline Direct Testimony Claim	2,862
Change for Updates and Corrections	515
Change for DRI Spring 1997 Fuel Forecast	(640)
Change for Accounting Related Differences	(434)
Result with All Changes	2,303
Change for EIA Fuel Forecast	(438)

Thus, the update supports the reasonableness of PECO's initial market price forecast, and indicates a trend toward lower market value.

Second, I have compared PECO's updated market value projections with the other projections currently before the Commission in this or other restructuring proceedings. PECO's current projections fall in the middle of the range of projections, as shown below.



PECO's position in the middle of the range supports the validity and reasonableness of PECO's market value projections.

Third, Mr. Falkenberg and Mr. Smith are only able to arrive at their significantly overstated market value projections due to their use of incorrect assumptions and overly simplistic, and therefore inexact, models. Using their own spreadsheets, I have approximately quantified the errors in their market value projections in order to show how Mr. Falkenberg's $4.81 billion projection and Mr. Smith's $4.65 projection are properly reduced to PECO's $2.3 billion projection of market value.

Mr. Falkenberg's overstated projection can be corrected by progressively calculating the effect of the following inputs:

Corrections to Mr. Falkenberg's Projection

Market Value - $ Billion NPV 1999

	Change*	Running Total**
Falkenberg Direct Testimony		4.81
Discount Rate	0.55	4.26
Capacity Prices	0.51	3.79
A&G Decommissioning	0.46	3.36
PECO Marginal Units	0.26	3.14
Half year NPV in 1999	0.23	2.94
Other	0.64	2.30

* Change from Direct Testimony

** Running total incorporating changes previously listed

Similarly, Mr. Smith's overstated projection can be corrected by progressively calculating the effect of the following inputs:

Corrections to Mr. Smith's Projection

Market Value - $ Billion NPV 1999

	Change*	Running Total**
Smith Direct Testimony		4.65
Discount Rate	0.65	3.99
A&G and Decommissioning	0.40	3.64
Half year NPV in 1999	0.21	3.48
Energy Revenue Growth	0.47	3.12
DRI Revised Fuel	0.64	2.48
Other	0.18	2.30

* Change from Direct Testimony

** Running total incorporating changes previously listed

These corrections are further explained in Section V of my testimony.

II. UPDATE OF GENERATION MARKET VALUE ANALYSES

Q. **Why has PECO decided to update the three market value analyses which it has submitted in this proceeding?**

A. PECO believes that it submitted a range of reasonable market value projections with its initial filing. However, in the interest of resolving the market value issue, PECO has attempted, in its rebuttal case, to eliminate as much controversy from its market value projections as possible while sustaining the integrity of its models. Therefore, as to all three market value analyses, PECO has incorporated a more current fuel forecast, has utilized only publicly available data for heat rates and has responded to valid criticisms and proposals of the intervenors. I set forth below the general nature and reasons for these changes as well as the effect these changes have on PECO's market value projections. Dr. Hieronymus and Mr. Rose will also address in their rebuttal testimony the effect of these changes on the PHB and ICF analyses. Exhibit JFB-11 provides further detail regarding the effects of the changes on the three PECO models.

Q. **What are the most significant revisions PECO has made to its market value analyses?**

A. With respect to all three of its market value analyses, PECO has substituted the more current Spring 1997 DRI McGraw-Hill fuel forecast and used EIA Form 860 heat rates. PECO's other market value witnesses will discuss changes of lesser importance in their rebuttal testimony.

Q. **Why has PECO decided to utilize EIA Form 860 heat rates as the basis of heat rates in its models?**

A. PECO considers EIA Form 860 heat rates to be appropriate heat rates, such that they can be substituted into the PECO models without compromising the integrity of their results. Additionally, PECO seeks to eliminate as much controversy as possible from its market value analyses. Thus, rather than continuing to use the unique and partly confidential data bases utilized by each of PECO's market value models for PECO's direct testimony, PECO requested that PHB, ICF and EDS modify their data bases such that projections of heat rates are based on the 1995 EIA Form 860 data (the most current EIA Form 860 data available). The EIA

Form 860 data is used to establish full load heat rates for existing units. This modification should enable the Commission to compare more meaningfully the three PECO models against each other and against those of the intervenors.

Q. **Now that all three PECO models are utilizing the most current EIA Form 860 data, will their heat rates be identical?**

A. No. Differences will remain due to the fact that the each of the three PECO market value witnesses uses a different means to develop the heat rates based on the capabilities of each witness's model and on whether incremental (PHB and EDS) or average (ICF) heat rates are modeled. Nonetheless, the EIA Form 860 importantly provides a consistent and reasonable starting point for the heat rates used in each model.

Q. **You also stated that PECO updated its fuel forecast. Why was this necessary?**

A. The Fall/Winter 1996 DRI forecast used in PECO's QRO proceeding, and in the direct testimony in this proceeding, has been updated by DRI to a Spring 1997 forecast since the time of the initial filing. Thus, a fuel forecast update was warranted.[1/]

1/ "Fuel forecast" is referred to as the "escalator" by several other witnesses, because it represents the general escalation rate of fuel prices.

Q. **Generally, what does the new DRI fuel forecast reflect?**

A. As shown in Exhibit JFB-12, the Spring 1997 DRI forecast shows a further decrease in fuel prices.

Q. **In addition to the changes in heat rate source and fuel forecast discussed above, it appears that the PHB and EDS analyses include modified calculations of fixed charge rates for new generation. Why did PECO decide to make this revision?**

A. PECO accepts Mr. Falkenberg's suggestion that the fixed charge rate for new units should include the cost of state income taxes. The projections presented in this rebuttal testimony and that of Dr. Hieronymus incorporate those costs. As a result, the PECO market value of the units increased somewhat. The ICF projection presented in PECO's direct testimony already incorporated state income taxes into the fixed charge rate for new units, and thus did not require revision on this point.

Q. **Did EDS make any other revisions to its market value analysis?**

A. Yes. After the initial filing, EDS became aware of an omission in its analysis, and accordingly corrected the analysis to account for the magnitude of the transmission limits between regions.

Q. **With respect to PECO's market value models, what results were obtained by making the changes discussed above?**

A. Exhibit JFB-11 presents revised market value analyses based on the modifications discussed above. Use of the EIA Form 860 heat rates and the incorporation of state income taxes had the effect of increasing PHB's market value projection by $515 million from the initial filing, EDS's by $225 million, and ICF's by $25 million. However, these increases were more than offset by decreases of $640 million (PHB), $654 million (EDS) and $429 million (ICF) resulting from use of the updated DRI fuel forecast.

Q. **Did PECO make any other modifications to the market value analyses set forth in its initial filing?**

A. Yes. In addition to the market value related changes made by PHB, ICF and EDS at PECO's request, PECO made some internal changes to the analysis, at the suggestion of the intervenors, relating to the allocation of A&G expenses, fossil decommissioning charges when units are life extended and the appropriateness of PECO's discount rate. As these changes are not directly related to the issue of market value, but are more of an accounting nature, they are discussed in Mr. Hill's testimony, PECO Statement No. R-1. Exhibit JFB-11 includes a revised market value analysis incorporating these additional modifications into the market price projections of PHB, EDS and ICF. PHB's current projection of market value is $2.303 billion.

Q. **What exhibits are you submitting with your testimony to illustrate the updates and modifications you have described?**

A. I am submitting the following exhibits: (a) Exhibit JFB-13 presents PECO's Generation All Hours Market value, (b) Exhibit JFB-14 presents PECO's Generation All Hours Market value for Energy and PECO's Generation Market value for Capacity, (c) Exhibit JFB-15 presents PECO's Generation Market value, (d) Exhibit JFB-16 presents PECO's Generation Market Revenue, and (e) Exhibit JFB-17 presents PECO's Generation Market Revenue Net of Fuels. Collectively, these exhibits incorporate all changes and adjustments and present the current best estimate of PHB, EDS and ICF of the value of PECO generation.

Q. **PAIEUG has utilized the Energy Information Administration ("EIA") fuel forecast. OCA witnesses, either in past testimony or in discussions with you, generally support the use of the EIA fuel forecast. Has PECO compared the results of its updated analyses to the results that would be obtained by substituting the EIA forecast for the updated DRI forecast?**

A. Yes. PECO requested that PHB, EDS and ICF run their models using the current EIA forecast.

Q. **Why did PECO request this comparison "run" when PECO is sponsoring the updated DRI fuel forecast in its testimony?**

A. PECO hopes, that by providing a run using the EIA fuel forecast, it will be able to remove fuel forecasting as a source of controversy in PECO's market value projections. PECO also believes that showing a run using the EIA fuel price forecast in all three of PECO's models will facilitate comparisons among the PECO models themselves, and among all models submitted in the proceeding.

Q. **With respect to the PECO models, what results were obtain by substituting the EIA fuel forecast for the DRI updated fuel forecast?**

A. Exhibit JFB-11 presents a revised market value analysis based on this change. Generally, EIA forecasts lower gas prices, and higher or lower coal and oil prices, depending upon the year, compared to the updated DRI forecast. Using the EIA forecast in the PHB model resulted in a significant decrease in PECO's market value. Specifically, the change in fuel forecast decreased market value by $438 million. Making the same change in the EDS model resulted in a decrease in market value of $655 million, and in the ICF model a decrease of $384 million.

Q. **The intervenors generally complained that PECO's models contained mistakes and that PECO's market value figure was too low. Yet you seem to be saying that correcting errors and making the above changes suggested by the intervenors, in particular using Mr. Falkenberg's EIA fuel forecast, actually *decreased* PECO's market value further. Is that correct?**

A. Yes. PAIEUG suggested that PECO include state income taxes in the fixed charge rate for new units, and PECO did so. PAIEUG and OCA support the EIA fuel forecast, so PECO ran its models using that forecast. Intervenors questioned PECO's heat rate sources, so PECO substituted publicly available EIA Form 860 heat rate data. Intervenors were unhappy with PECO's allocations of A&G costs, and so PECO modified them. Additionally, PECO and EDS corrected some inadvertent mistakes found in earlier calculations to eliminate as much controversy as possible from their analyses. The net result of all of these modifications was a significant *decrease* in market value compared to the market values presented in PECO's direct testimony. The PHB market value projection decreased by $997 million, the EDS projection by $1.528 billion, and the ICF projection by $1.215 billion.

III. COMPARISON OF MARKET VALUE PROJECTIONS

Q. **How many projections of market value for PECO's generation region have been submitted in this or other restructuring proceedings currently before the Commission?**

A. To date, seven projections of market value have been submitted. Five of these projections are part of the record in this case: three by PECO, one by PAIEUG (through Mr. Falkenberg) and one by OCA (through Messrs. LaCapra and Smith). Two other projections have been presented by PP&L and GPU in their respective restructuring filings. Mr. Falkenberg and Mr. Smith have presented the same projections in PP&L's filing as in this case.

Q. **How do these price projections compare to historical price patterns and to each other?**

A. Exhibit JFB-18 shows the historical all hours market value for energy from 1984 through 1996 and the seven projections of market value for energy from 1999 through 2015. Historical market price for energy has steadily decreased since 1984. Projections steadily increase from 1999 forward. Thus, if historical price patterns continue, all of the projections submitted in this proceeding will have overstated market price.

Q. **How do PECO's updated energy value projections compare to the other projections?**

A. Exhibit JFB-14 presents annual and levelized values for all hours market price for energy. The three PECO analyses fall in the middle of the range of projections. PECO's projections therefore are clearly reasonable, rather than extreme, as suggested by several of the intervenors.

Q. **How do PECO's updated projections of PECO generation market price weighted by output and of market revenue compare to the other studies?**

A. Exhibits JFB-15 and JFB-16 show the three PECO projections falling significantly below PAIEUG's and OCA's projections, strongly suggesting that PAIEUG and OCA overstate market value.

Q. **How do PECO's updated projections of market revenue net of fuel compare to the other projections?**

A. Exhibit JFB-17 presents the market revenue net of fuel projections of PAIEUG, OCA and PECO. Generally, a market revenue projection "net of fuel" is a good indicator of value because such a projection appropriately accounts for the offset of market revenues by inevitable fuel costs. These projections reveal a significant disparity -- Mr. Falkenberg estimates $269 million more annual revenue net of fuel than PHB, and Mr. Smith estimates $765 million more annual revenue net of fuel than PHB.

Q. **What do you conclude from these price and revenue projections?**

A. Due to incorrect assumptions about capacity value and energy value net of fuel, and limitations in their models, as discussed above, Mr. Falkenberg and Mr. Smith project significantly higher revenue from PECO generation than does PECO. On the other hand, based on their estimates of all hours market value, if the PP&L witness and the GPU witness were to project revenue for PECO generators, they would project materially lower revenue than the PECO witnesses have projected.

Q. **What do you conclude from your comparison of the seven energy and capacity price projections which have been submitted to the Commission?**

A. PECO's estimates of market value are reasonable, and, indeed, quite conservative. PECO presented a range of projections in order that the Commission might be in a better position to gauge the reasonableness of the market value projection PECO has presented to the Commission. As this comparison demonstrates, PECO's own range of reasonableness falls in the middle of the range of all market value projections submitted to date, further supporting the validity and reasonableness of PECO's estimates.

IV. AREAS OF AGREEMENT

Q. **Much of the intervenors' direct testimony was dedicated to identifying areas of disagreement with the PECO models. Are there any points on which PECO and the intervenors agree with respect to the calculation of market value?**

A. Yes. In fact, PECO and the intervenors agree substantially on a number of significant points. For example, PECO, PAIEUG and OCA materially agree on the following issues: (1) the PECO methodology for computing stranded costs, (2) load growth, (3) nuclear capacity factor, (4) reserve margin for capacity, (5) the belief that low capacity prices will rise before new capacity will be added, (6) a market clearing price for energy based upon the cost of serving a small increment of load, and (7) a market clearing price for capacity based on the lesser of the fixed annual cost of a combustion turbine or the fixed annual charge of a combustion turbine less its energy benefits.

V. CRITIQUE OF PAIEUG AND OCA MARKET VALUE PROJECTIONS

Q. **Please describe the model used by PAIEUG's witness, Mr. Falkenberg, in this proceeding to project market value.**

A. Mr. Falkenberg uses a "homemade," simplified model for projecting market value that he has developed and added to over time.

Q. **In what contexts and for what purposes is his model generally used?**

A. It is my understanding that no one other than Mr. Falkenberg has ever used his model. Mr. Falkenberg's model was created simply to support his testimony in various regulatory proceedings. To my knowledge, no actual participants in the electric utility market have ever utilized Mr. Falkenberg's model to assist them with planning, purchasing or marketing decisions.

Q. **How does Mr. Falkenberg's model compare to PECO's three models in terms of abilities and limitations?**

A. Mr. Falkenberg's model is much less sophisticated than the models used by PECO. For example, Mr. Falkenberg's model is incapable of performing unit commitment, and simply cannot represent the restrictions on the manner in which units actually operate. His model cannot reflect differences between power levels in a given hour, and ignores time differences over the course of the year by modeling only two periods. Additionally, Mr. Falkenberg's model is not able to determine and model transmission constraints. Importantly, the model also lacks sensitivity with respect to imports and exports. The validity and usefulness in this proceeding of Mr. Falkenberg's projections are seriously compromised by his model's limitations.

Q. **Please describe the model used by OCA's witness, Mr. Smith, in this proceeding to project market value.**

A. Mr. Smith uses the ENPRO model, which is commercially available.

Q. **In what contexts and for what purposes is the ENPRO model generally used?**

A. It is my understanding that the ENPRO model is typically used for multi-regional, multi-company market price analyses, generally for small purchasers of power who desire to model the prices that may be available to them in different regions of the country and from different companies.

Q. **How does Mr. Smith's model compare to PECO's three models in terms of abilities and limitations?**

A. When used properly, the ENPRO model appears to be an adequate model for projecting market value, as indicated above. However, for reasons that are unclear, Mr. Smith opted to pare down the ENPRO model by disregarding many of the model's important features, thereby sacrificing precision in his results. For example, Mr. Smith's model assumes that units can be turned on and off on an hourly basis. While this pattern of operation may be simpler to model, it is certainly not realistic.

Q. **Turning first to the PAIEUG model, Mr. Falkenberg contends that his model is valid because it can replicate the results of PECO's three market analyses. Do you agree?**

A. No. Mr. Falkenberg's model suffers from numerous limitations and is simply not of the same quality or level of sophistication as the three market value models sponsored by PECO in this proceeding. (See Dr. Hieronymus's testimony, PECO Statement No. R-6). Mr. Falkenberg's assertion that his study is validated by the fact that it can replicate three market analyses that he contends are invalid is somewhat puzzling. Even assuming there was logic to this theory, Mr. Falkenberg's results are simply not that close to PECO's results in early years modeled, such as 1999. (See Exhibit RJF-8). The price differences apparent in Exhibit RJF-8 demonstrate that Mr. Falkenberg's model overvalues PECO generation by approximately $150 million compared to each of the three PECO models. Thus, Mr. Falkenberg's model is not able to replicate validly the results of PECO's three market value analyses.

Q. **Mr. Falkenberg projects that PECO generation has approximately $2.5 billion more value than does PECO's PHB analysis, and over $2.2 billion**

more value than PECO's EDS and ICF analyses. What are the reasons for *the discrepancy between the results produced by PAIEUG's model and the* PECO models?

A. There are three assumptions that stand out in the PAIEUG analysis as the basis for the disparity: (1) use of a lower, outdated discount rate; (2) a higher marginal price of new capacity; and (3) higher operation and value for PECO's marginal generating units.

Q. **Can you quantify the effect of these factors on Mr. Falkenberg's projection of market value?**

A. Yes. I generated an estimate of the effect of each factor using Mr. Falkenberg's spreadsheet presented in Exhibit RJF-9. My results are presented in Section I of my testimony. Employing the lower, outdated discount rate and half-year NPV in 1990 results in a market value increase of $783 million. Use of a higher marginal price of new capacity further increases Mr. Falkenberg's projection of market value by $506 million. Finally, using high operation and value for PECO's marginal generating units further increases the market value by $256 million. The overall effect of incorporating interdependencies of these three factors on Mr. Falkenberg's market value projection is to increase it by $1.545 billion.

Q. **With respect to the first major difference between PECO's and PAIEUG's models, do you agree with Mr. Falkenberg's accounting techniques, in particular his discount rate?**

A. No. Mr. Falkenberg proposes a discount rate of 7.6% which is based on Mr. Deardorf's testimony in the QRO proceeding. Mr. Deardorf no longer supports this rate in his testimony in this proceeding. Instead, PECO witness Mr. Brennan supports a discount rate of 8.7%. (See PECO Statement No. 11-R).

Q. **With respect to the next important factor, do you agree with Mr. Falkenberg's valuation of PECO's marginal units?**

A. No. I believe that Mr. Falkenberg has vastly overstated the value of PECO's marginal units. For example, Mr. Falkenberg projects net present values of the sum of six PECO oil or gas steam units -- Cromby 2, Delaware 7 and 8, Eddystone 3 & 4, and Schuylkill 1 -- at $619 million compared to PECO's projected range of $38 to $137.

Q. **What aspect of Mr. Falkenberg's analysis could account for such a sizeable difference in value?**

A. Mr. Falkenberg incorrectly assumes that all hydroelectric resources, all imports into PJM and all output from non-utility generation will enter the market independent of market value, which leads him to project that the energy available from those resources will be consistent over every hour of the year. The problem with Mr. Falkenberg's modeling is that each of these resources has some flexibility to provide more energy during higher cost times (times with higher load). In PECO's case, for example, during 1996, Conowingo hydroelectric station contributed 325 MWh/hr during on-peak times and 245 MWh/hr during off-peak times. As another example, during three representative months in 1996, on-peak MWh western imports into PJM were 11% higher than off-peak hours. As a result of his incorrect assumptions regarding the operation and availability of those resources, Mr. Falkenberg has significantly increased market values during on-peak times, which causes a substantial and improper increase in Mr. Falkenberg's market value calculation.

Q. **What implications does Mr. Falkenberg's projection of consistent hourly energy availability from imports, hydroelectric generation and non-utility generation have in terms of the reliability of supply?**

A. Reliability of supply could not be maintained if the system operated as projected by Mr. Falkenberg because too few resources would be available during on-peak times. In Mr. Falkenberg's model, there are approximately 100 hours per year during which supply is less than demand. In reality, during the last 10 years there have been only 5 hours that supply could not meet demand in PJM -- four hours on January 19 during the unusually brutal winter of 1994, and one hour on July 5, 1990. Mr. Falkenberg's model is simply unsupported by actual system operations and history.

Q. **With respect to the third major difference between the results obtained from the PECO and PAIEUG models, the marginal price of new capacity, do you agree with Mr. Falkenberg's projection of the future costs of combustion turbines?**

A. No. Mr. Falkenberg overstates capital costs for combustion turbines ("CT"s) by using too high an escalation factor, and by commencing this high escalation rate in 1995. Mr. Rose addresses the unreasonableness of these assumptions, and their impact on Mr. Falkenberg's analysis, in his testimony. (See PECO Statement No. 22-R). In short, Mr. Falkenberg's overstated estimates of capital costs increase his market value of generation.

Q. **Mr. Falkenberg contends that EDS's capital costs for new combined cycle units and CT units are \$625/kW and \$325/kW, respectively. Is this a fair characterization of such costs?**

A. No. EDS's analysis reflects an improvement in technology that will lower real costs of combined cycle ("CC") and CT units until 2002. Thus, it becomes necessary to restate 2002 costs in 1996 dollars in order to make a meaningful comparison of EDS's cost estimates during that time period to the cost estimates of other witnesses. The 2002 costs expressed in 1996 dollars are \$536/kW for CCs and \$279/kW for CTs.

Q. **Turning to Mr. Falkenberg's cost estimates for fixed and variable O&M for new capacity, Mr. Falkenberg has estimated for CTs fixed O&M costs of $6 to $7/kW-yr and variable O&M costs of $0/MWh. Do you agree with his estimates?**

A. Absolutely not. It is incredible that Mr. Falkenberg can anticipate absolutely no variable costs in the O&M of new CTs. Instead, he artificially inflates his fixed O&M estimate by lumping any anticipated O&M expenses into fixed O&M.

Q. **What are the implications of moving costs from variable O&M into fixed O&M?**

A. The amount of fixed O&M of a new unit affects the capacity price, and therefore the capacity revenue, for all PECO units for the entire year. The amount of variable O&M of a new unit affects the amount of energy payments to all PECO units only during the hours that the new unit is on the margin and setting the margin price. Obviously capacity revenue for the entire year has a significantly greater effect than energy value for only a small portion of the year on PECO's overall market value. Thus, moving costs from variable O&M to fixed O&M greatly increases market revenue to PECO units in Mr. Falkenberg's analysis, and renders his analysis seriously flawed.

Q. **How important is the accuracy of the fixed O&M cost for new capacity on the overall validity of a market value projection?**

A. Very important. Generally, capacity price is set by the marginal cost of capacity for the year, and currently the cheapest new capacity is a CT unit. With CTs setting the capacity price in the market, fixed O&M costs of CTs are a significant driver in the projection of market value.

Q. How do Mr. Falkenberg's annual capacity prices compare to those of PECO, OCA, GPU and PP&L?

A. Exhibit JFB-14 presents this comparison. Mr. Falkenberg's estimates are consistently higher than those of PECO, OCA, GPU and PP&L.

Q. Turning to OCA's model, do you agree with Mr. Smith's discount rate?

A. No. Like Mr. Falkenberg, Mr. Smith proposes a discount rate of 7.6% which is based on Mr. Deardorf's testimony in the QRO proceeding. As discussed above, Mr. Deardorf no longer supports this rate based on his updated testimony in this proceeding. Instead, PECO supports a discount rate of 8.7%. Mr. Smith's reliance on an outdated discount rate increases his projection of PECO's generation market value by $654.

Q. Is Mr. Smith's projection of the market value of energy and capacity for PECO units consistent with PECO's three analyses?

A. For capacity, yes; but for energy, no. Mr. Smith's projection of the value of capacity is relatively consistent with the projections of the three PECO models.

With respect to the value of energy, his projection is relatively consistent in 1999 but by 2015 is well above PECO's projections. Mr. Smith's projection of all hours market value for energy is 9% higher than the three PECO projections when levelized over the period of 1999 through 2015.

Q. **Does Mr. Smith adequately explain the reason for the difference between his and PECO's projections of the value of energy during the 1999 to 2015 time period?**

A. No. Aside from differences in heat rate methodology, Mr. Smith generally claims to be using publicly available data or the 1996 Fall/Winter DRI fuel price forecast. He does not specify the methodology associated with his model in any meaningful fashion. Thus, his results are little more than an unsupported bottom line figure.

Q. **What factor do you believe is responsible for the difference in value?**

A. I believe that Mr. Smith's modeling of the fuel type used in existing and future generation causes much of the difference. Mr. Smith developed his data base of existing units from FERC Form 1 data. When the FERC Form 1 failed to distinguish the fuel type used by units within a station, Mr. Smith assigned a blend of fuels and a price that is the result of the weighted prices of that blend. For new CTs, Mr. Smith also assigned a blended price of 50% distillate oil and 50% gas.

Q. Is Mr. Smith's blend of gas and distillate oil a reasonable fuel type assumption with respect to new CTs?

A. No. Distillate oil prices are projected by DRI to be approximately 80% higher than gas prices, such that Mr. Smith ends up modeling new CTs, which will increasingly set the market value, using a fuel price that is 40% higher than gas. It is unrealistic to assume that new CTs would be fueled in such an uneconomic fashion. Instead, builders of new capacity will prefer that new units use gas because gas prices are significantly lower. Mr. Smith projects gas availability for new CC units. There is no valid reason to believe that gas will not be available to fuel new CTs as well.

Q. *Can you quantify the differences between Mr. Smith's model and PECO's* PHB model that account for his higher market value?

A. Yes. My table in Section I of my testimony compares Mr. Smith's market value projection to PECO's PHB market value projection. Each major difference between the models is broken out to demonstrate the dollar amount associated with it.

VI. RESPONSE TO CRITICISMS REGARDING THE EDS MODEL

Q. Mr. Falkenberg discusses "heat rates" at great length. Would you explain the term "heat rate"?

A. A heat rate is simply the conversion factor that indicates the amount of fuel that must be used in order to produce a unit of output. That factor varies according to the level of output. Heat rates are most often expressed as incremental heat rates because most generation cannot go from zero output to power production without engaging in an involved start-up procedure. Once a unit is committed to operate, the relevant heat rate (the incremental heat rate) reveals the amount of extra fuel it will take to produce one more unit (or increment) of output.

Q. **Mr. Falkenberg has asserted that the heat rates employed in the EDS model are erroneous and systematically biased such that market energy prices are understated. Do you agree with this assessment?**

A. Absolutely not. The EDS model properly developed heat rates from publicly available FERC Form 1 data and a 1989 EPRI Technology Assessment Guide (TAG), neither of which is systemically biased or has a tendency to understate profit margins.

EDS developed incremental heat rates using factors from EPRI TAG to convert average heat rates as plants operate to full load heat rates to incremental heat rates. These techniques and data remain valid. EPRI TAG is an industry-recognized source of information that was specifically compiled to provide data for analytical studies such as EDS's. The latest 1993 EPRI TAG does not materially change the incremental heat rates at various load levels. Thus, there is simply no basis for Mr. Falkenberg's assertion.

Nonetheless, PECO accepts that using EIA Form 860 heat rates is another reasonable way of developing full load heat rates for generating units from publicly available data. Indeed, Mr. Falkenberg bases his heat rates on EIA Form 860 data. Therefore, as discussed in Section II of my testimony, PECO has adopted these heat rates as well in order to eliminate controversy. The results of that modification to the EDS model are discussed in Section II.

Q. **Mr. Falkenberg asserts that EDS's fuel price assumptions are unrealistic and understate market value. Do you agree?**

A. No. Mr. Falkenberg's main criticism is that the EDS model assumes that gas fuel would be used exclusively for "dual units" -- units that have the capability of using either gas or oil. The simple fact is that fuel price projections all strongly suggest that, going forward, gas will be the fuel of choice. It is true that, historically, dual units have used oil at times when it was cheaper to use oil than gas. However, fuel forecasts suggest that gas will continue to be cheaper than oil, such that it is reasonable to assume that gas, not oil, will be used to fuel dual units.

While it is true that gas supply to dual units is typically interruptible, it is incorrect to assert that such interruptions are frequent enough to override a clear economic incentive to utilize a cheaper fuel. In fact, during the 1993 through 1996 period, PECO averaged only 84 hours of supply interruption per year -- far from a significant curtailment that would materially influence fuel choice or affect electric generation market value.

Additionally, the reasonableness of EDS's assumption that existing residual oil units will convert to gas is clearly supported by the large number of oil units that recently have undergone such conversion and by the relatively low number of residual oil units remaining in the regions modeled. In short, the EDS study and PECO's analysis properly and reasonably project the mix of gas and oil fuel that will be utilized going forward.

Q. **Mr. Smith also criticizes EDS's fuel price analysis, and in particular, appears to suggest that Exhibit JFB-5 is misleading. Please comment.**

A. Mr. Smith is correct, of course, that Exhibit JFB-5 does not represent the fuel prices used by each unit. It was not meant to. However, this is due to the limitations of any one exhibit in explaining a complex issue rather than to intentional misrepresentation. For many reasons, including differences in transportation costs and differences in the quality of fuels, fuel prices differ between units. Exhibit JFB-5 is intended to present underlying assumptions about regional average prices rather than unit-by-unit fuel prices. Mr. Smith is also correct that Exhibit JFB-5 represents a blend of distillate and residual oil prices which varies by year. The actual oil price for each year is shown in Exhibit JFB-12.

Q. **Mr. Falkenberg criticizes EDS's choice of markets to model. Do you agree?**

A. No. EDS not only modeled PJM, but also ECAR and SERC, in order to more realistically reflect imports to and exports from PJM, including imports and exports during on- and off-peak periods. It is curious that Mr. Falkenberg would choose to quibble over whether ECAR, SERC, NYPP or NEPOOL are the better markets to model along with PJM when he chooses in his own model to ignore completely the issue by modeling only PJM. Mr. Falkenberg is, in fact, forced to model only PJM because his model is not sophisticated enough to manage imports and exports from other interconnections.

VII. RESPONSE TO ENVIRONMENTALISTS' COMMENTS REGARDING INTEGRATED T&D PLANNING AND ENERGY CONSERVATION PROGRAMS

Q. **Mr. Schoengold, witness for the Environmentalists, asserts that an integrated approach to T&D planning will be required after PECO generation is deregulated. Is PECO taking steps to ensure that such a plan is in place?**

A. Yes. In anticipation of the transition to restructuring and retail competition, PECO energy has changed its approach to planning to meet future load growth. Currently, and for the foreseeable future, PECO energy will employ spatial growth forecasting to identify load growth trends within the service territory, to forecast load growth and to size distribution capacity to meet load growth. Utilizing land use growth simulation software, PECO has produced a geographically referenced forecast of the locations of future load growth for residential, commercial and industrial customer classes for a twenty-year planning horizon. The simulation software is calibrated to actual land development data (building permit data and subdivision/land development submissions) obtained from the county planning commissions. Areas of future load growth are identified and a forecast of when load growth reaches the firm capacity rating of each 34kV and 13kV substation has been produced.

During the next twenty years (the forecast period), PECO will annually track growth and development by substation service area. As the threshold for load relief approaches, PECO will utilize distribution load flow analysis software and strategic asset management software tools to evaluate and ultimately select the alternative which maximizes remaining available capacity and/or provides any needed additional capacity, in the most cost effective manner.

Q. **Mr. Schoengold's analysis includes several hypothetical energy conservation programs. Are these programs realistic?**

A. No. First, Mr. Schoengold's analysis of the potential for demand side management ("DSM") is based on a study of the electric generation market in Wisconsin which is of questionable applicability to Pennsylvania or PJM markets. Second, Mr.

Schoengold assumes that over 1200 MW of energy conservation programs could be implemented overnight. This is simply unrealistic, as it would take several years to implement the level of demand side management programs Mr. Schoengold envisions. Third, Mr. Schoengold ignores the crucial issue of the cost of such programs. As PECO explained in the QRO proceeding (TR 832-834) in response to the Environmentalists' proposal, the program proposed by Mr. Schoengold easily would cost over $1 billion, more than the purported reduction in stranded costs Mr. Schoengold claims the program would achieve. Finally, to the extent there are sales reductions associated with these energy efficiency programs, customers would continue to pay the same CTC per kWh as they would without such programs. For example, if sales were to drop by 10%, customers would see *no change in the CTC rate. In fact, transmission and distribution rates likely would* have to be increased once the cap on those rates ended. Furthermore, Mr. Schoengold's proposal would result in a shifting of costs between those customers that participate in such programs and those that do not unless the cost of the programs were recovered only from those customers who participated.

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

A. Yes.

Net Present Value of PECO Generation

$ Million NPV 1999			
	PHB	**EDS**	**ICF**
Baseline Direct Testimony Claim	2,862	3,650	3,488
Change for Updates and Corrections	515	225	25
Change for DRI Spring 1997 Fuel Forecast	(640)	(654)	(429)
Results with Market Changes	2,737	3,221	3,084
Change for Accounting Related Differences	(434)	(444)	(427)
Results with All Changes	**2,303**	2,777	2,657
Change for EIA Fuel Forecast	(438)	(655)	(384)
PECO Revised with EIA Fuel	1,865	2,122	2,273

Historical and Expected Fuel Prices

Source: DRI McGraw-Hill World Energy Service U.S.Outlook, Spring 1997 Released May 1997

Price of Fuel Delivered to Middle Atlantic Electric Utilities

(Dollars per Million Btu)				
			Residual	Distillate
	Coal	Natural Gas	Oil	Oil
1990	1.55	2.35	3.47	5.38
1991	1.55	2.18	2.64	4.69
1992	1.50	2.37	2.62	4.33
1993	1.46	2.60	2.51	4.10
1994	1.45	2.22	2.56	3.89
1995	1.39	2.07	2.63	3.87
1996	1.41	2.96	3.17	4.93
1997	1.44	2.65	3.02	4.58
1998	1.46	2.37	2.94	4.54
1999	1.51	2.35	2.89	4.51
2000	1.56	2.39	2.96	4.64
2001	1.59	2.53	3.13	4.89
2002	1.62	2.66	3.28	5.12
2003	1.66	2.76	3.43	5.37
2004	1.69	2.86	3.59	5.62
2005	1.71	2.97	3.82	5.95
2006	1.74	3.09	4.02	6.26
2007	1.77	3.24	4.23	6.59
2008	1.81	3.39	4.45	6.94
2009	1.85	3.57	4.69	7.30
2010	1.90	3.75	4.94	7.68
2011	1.91	3.93	5.22	8.12
2012	1.96	4.11	5.51	8.55
2013	2.01	4.33	5.82	9.02
2014	2.07	4.56	6.15	9.52
2015	2.12	4.82	6.50	10.07

PECO Generation All Hours Market Price

	$/MWh						
	PHB (1)	**EDS (2)**	**ICF (2)**	**OCA**	**PAIEUG**	**PP&L**	**GPU (3)**
1999	22.1	24.2	24.8	24.6	26.7	24.5	23.5
2000	24.3	26.2	27.0	27.1	29.3	26.3	26.4
2001	27.5	29.3	29.5	29.9	31.3	28.3	27.8
2002	28.8	30.5	30.9	31.3	32.3	29.7	29.0
2003	30.2	31.6	31.7	33.2	33.2	30.6	30.3
2004	31.6	32.8	32.8	34.6	34.0	31.5	31.7
2005	32.9	33.8	34.0	37.2	35.1	31.0	33.0
2006	34.3	34.9	35.5	39.7	36.5	32.1	33.8
2007	35.8	36.4	36.8	41.8	37.9	34.7	34.6
2008	37.3	37.8	38.4	44.3	39.3	35.8	35.1
2009	38.6	39.0	39.9	45.8	40.7	37.1	35.8
2010	40.7	41.0	41.7	48.8	42.2	38.2	36.7
2011	42.7	42.4	43.2	50.7	43.8	38.3	38.0
2012	44.8	44.0	44.9	53.0	45.5	39.4	39.0
2013	47.0	45.7	46.9	55.1	47.2	41.5	41.6
2014	49.3	47.8	49.0	57.6	49.0	41.7	43.0
2015	51.7	50.0	50.7	60.4	50.7	42.8	44.6
Levelized	33.2	34.0	34.6	37.8	35.8	32.2	32.1
1999-2015							

(1) Limerick market price for energy plus all hours capacity price. Limerick is a close approximation to PECO generation all hours market price because Limerick operates all hours that it is available and is located in eastern PJM.
(2) PECO generation all hours market price for energy plus all hours capacity price
(3) Met Ed

PHB	PECO Energy Witness Hieronymus
EDS	PECO Energy Witness Bustard
ICF	PECO Energy Witness Rose
OCA	Office of Consumer Advocate Witness D. Smith
PAIEUG	Philadelphia Area Industrial Energy Users Group Witness Falkenberg
PP&L	Pennsylvania Power & Light Witness Jones, PP&L Docket
GPU	GPU Energy Witness Roberts, GPU Energy Docket

PECO Generation All Hours Market Price for Energy

	$/MWh						
	PHB	EDS	ICF	OCA	PAIEUG	PP&L	GPU
1999	20.2	21.5	22.2	22.4	23.9	22.0	20.9
2000	21.3	22.6	23.5	23.6	25.8	23.0	22.3
2001	22.3	24.1	24.5	25.1	26.0	24.0	23.4
2002	23.5	24.9	25.8	26.4	26.7	24.0	24.2
2003	24.7	25.8	26.5	28.1	27.1	25.0	25.4
2004	25.9	26.8	27.4	29.4	27.3	26.0	26.7
2005	27.1	27.6	28.5	31.8	28.3	26.0	27.9
2006	28.3	28.4	29.8	34.1	29.5	27.0	28.5
2007	29.5	29.8	31.0	36.0	30.9	29.0	29.2
2008	30.8	31.1	32.4	38.3	31.9	30.0	29.6
2009	32.1	32.0	33.7	39.6	33.3	31.0	30.1
2010	33.8	33.7	35.3	42.3	34.5	32.0	30.9
2011	35.5	35.0	38.4	44.1	36.0	32.0	32.0
2012	37.3	36.5	40.0	46.1	37.6	33.0	32.9
2013	39.3	37.8	41.9	48.0	38.8	35.0	35.3
2014	41.3	39.7	44.3	50.3	40.2	35.0	36.6
2015	43.4	42.0	46.2	52.8	41.6	36.0	38.0
Levelized	27.7	28.2	29.7	32.7	29.7	27.1	27.2
1999-2015							

PECO Generation Market Price for Capacity

	$/kW-year						
	PHB	EDS	ICF	OCA	PAIEUG	PP&L	GPU
1999	16.0	23.9	23.9	19.7	24.2	22.0	23.1
2000	27.0	31.1	31.1	30.4	30.8	29.0	35.5
2001	45.4	45.1	45.1	41.7	46.5	38.0	38.6
2002	46.7	49.1	46.7	43.1	49.0	50.0	41.9
2003	48.1	50.3	47.8	44.2	53.4	49.0	42.9
2004	49.6	52.7	49.4	45.7	58.2	48.0	44.0
2005	51.3	54.2	51.0	47.1	60.0	44.0	45.1
2006	53.1	57.3	52.9	48.9	61.2	45.0	46.2
2007	55.0	58.0	54.5	50.4	61.3	50.0	47.4
2008	56.9	58.7	56.5	52.2	64.4	51.0	48.5
2009	59.0	61.7	58.4	54.0	64.6	53.0	49.8
2010	61.0	64.1	60.8	56.2	67.4	54.0	51.0
2011	63.2	64.9	62.7	58.0	68.5	55.0	52.3
2012	65.5	65.8	65.1	60.1	69.7	56.0	53.6
2013	67.8	69.4	67.5	62.3	73.6	57.0	54.9
2014	70.2	71.3	69.8	64.5	77.3	59.0	56.3
2015	72.8	70.3	72.2	66.7	80.0	60.0	57.7
Levelized	48.0	50.8	49.0	45.1	53.7	44.6	43.2
1999-2015							

PECO Generation Market Price

Weighted by Output (1)

	$/MWh				
	PHB	**EDS**	**ICF**	**OCA**	**PAIEUG**
1999	24.3	25.1	27.3	27.4	30.3
2000	27.6	27.3	30.1	31.3	33.7
2001	32.6	31.0	34.0	35.5	37.3
2002	34.0	32.4	35.6	36.9	38.9
2003	35.4	33.5	36.5	39.0	40.2
2004	36.9	34.8	37.8	40.7	41.9
2005	38.4	35.8	39.3	43.5	43.1
2006	40.0	37.1	41.0	46.1	45.0
2007	41.6	38.6	42.5	48.1	46.4
2008	43.2	40.0	44.3	50.6	48.3
2009	45.0	41.3	46.1	52.2	49.8
2010	47.1	43.4	48.2	55.4	52.1
2011	49.3	44.9	52.3	57.6	53.7
2012	51.6	46.5	54.4	60.2	55.3
2013	54.0	48.4	56.8	62.5	57.6
2014	57.0	50.6	60.1	66.4	60.4
2015	58.3	52.7	61.5	71.0	60.6
Levelized 1999-2015	47.5	44.0	49.6	54.6	52.7

(1) - Weighted market price is the sum of market revenues for each PECO generating unit divided by the total output from all PECO generating units

PECO Generation Market Revenue

	Million Dollars				
	PHB	EDS	ICF	OCA	PAIEUG
1999	965	1,116	1,092	1,014	1,252
2000	1,105	1,231	1,217	1,156	1,412
2001	1,312	1,424	1,382	1,328	1,563
2002	1,376	1,494	1,450	1,399	1,616
2003	1,444	1,542	1,489	1,479	1,676
2004	1,517	1,602	1,540	1,547	1,725
2005	1,550	1,614	1,561	1,653	1,789
2006	1,618	1,679	1,627	1,771	1,850
2007	1,691	1,737	1,688	1,876	1,914
2008	1,768	1,803	1,762	1,997	1,979
2009	1,849	1,869	1,830	2,064	2,050
2010	1,936	1,961	1,910	2,196	2,108
2011	2,027	1,937	1,979	2,277	2,117
2012	2,123	2,002	2,062	2,392	2,207
2013	2,223	2,088	2,156	2,490	2,290
2014	2,168	2,026	2,099	2,434	2,219
2015	2,042	1,878	1,936	2,381	1,943
Levelized 1999-2015	2,194	2,216	2,199	2,404	2,423

PECO Generation Market Revenue Net of Fuel

Million Dollars					
	PHB	EDS	ICF	OCA	PAIEUG
1999	651	786	789	1,014	918
2000	781	892	893	1,156	1,064
2001	976	1,074	1,049	1,328	1,212
2002	1,024	1,138	1,103	1,399	1,262
2003	1,075	1,179	1,136	1,479	1,316
2004	1,129	1,234	1,179	1,547	1,364
2005	1,166	1,256	1,214	1,653	1,417
2006	1,216	1,304	1,271	1,771	1,467
2007	1,270	1,353	1,319	1,876	1,513
2008	1,326	1,401	1,378	1,997	1,565
2009	1,385	1,450	1,434	2,064	1,617
2010	1,455	1,525	1,501	2,196	1,673
2011	1,530	1,526	1,555	2,277	1,690
2012	1,608	1,579	1,618	2,392	1,756
2013	1,690	1,644	1,692	2,490	1,827
2014	1,642	1,589	1,640	2,434	1,766
2015	1,525	1,452	1,501	2,381	1,537
Levelized 1999-2015	1,639	1,710	1,702	2,404	1,908

PECO Historical All Hours PJM Billing Rate

$/MWh	
1984	44.4
1985	35.4
1986	26.6
1987	30.6
1988	25.8
1989	30.5
1990	26.0
1991	24.1
1992	21.8
1993	23.0
1994	23.6
1995	21.0
1996	21.5

PECO Generation All Hours Market Price for Energy

$/MWh							
	PHB	EDS	ICF	OCA	PAIEUG	PP&L	GPU
1999	20.2	21.5	22.2	22.4	23.9	22.0	20.9
2000	21.3	22.6	23.5	23.6	25.8	23.0	22.3
2001	22.3	24.1	24.5	25.1	26.0	24.0	23.4
2002	23.5	24.9	25.8	26.4	26.7	24.0	24.2
2003	24.7	25.8	26.5	28.1	27.1	25.0	25.4
2004	25.9	26.8	27.4	29.4	27.3	26.0	26.7
2005	27.1	27.6	28.5	31.8	28.3	26.0	27.9
2006	28.3	28.4	29.8	34.1	29.5	27.0	28.5
2007	29.5	29.8	31.0	36.0	30.9	29.0	29.2
2008	30.8	31.1	32.4	38.3	31.9	30.0	29.6
2009	32.1	32.0	33.7	39.6	33.3	31.0	30.1
2010	33.8	33.7	35.3	42.3	34.5	32.0	30.9
2011	35.5	35.0	38.4	44.1	36.0	32.0	32.0
2012	37.3	36.5	40.0	46.1	37.6	33.0	32.9
2013	39.3	37.8	41.9	48.0	38.8	35.0	35.3
2014	41.3	39.7	44.3	50.3	40.2	35.0	36.6
2015	43.4	42.0	46.2	52.8	41.6	36.0	38.0
Levelized 1999-2015	27.7	28.2	29.7	32.7	29.7	27.1	27.2

R-973953

PECO STATEMENT NO. 8-R

Phila 10/14, 15/14/97

B. Holbert

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCUMENT FOLDER

APPLICATION OF PECO ENERGY COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY

OF

THOMAS S. LAGUARDIA

Regarding Stranded Investment (Decommissioning - Nuclear and Fossil)

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF THOMAS S. LAGUARDIA

I. INTRODUCTION

Q. Please state your name and business address.

A. Thomas S. LaGuardia, 148 New Milford Road East, Bridgewater, CT 06752

Q. Have you previously participated in this proceeding?

A. Yes. I submitted direct testimony (PECO Statement No. 8) with PECO's Application for approval of its Restructuring Plan. A statement of my qualifications is contained in my direct testimony.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses issues pertaining to fossil and nuclear decommissioning raised in the testimony of Mr. Darren D. Gill, on behalf of the Office of Trial Staff ("OTS"); Messrs. Thomas S. Catlin and Richard LaCapra, on behalf of the Office of Consumer Advocate ("OCA"); Mr. Kollen, on behalf of the Philadelphia Area Industrial Energy Users Group ("PAIEUG"), and Mr. Bruce Biewald, on behalf of the Environmentalists, as follows:

- **Validity And Accuracy Of The Cost Estimates To Decommission Fossil-Fired Stations** (Mr. Kollen)
- **The Need For, And Appropriateness Of, Contingency** (Messrs. Gill and Catlin)

- **Post-Operation Fund Earnings For Nuclear Decommissioning** (Messrs. Kollen and Catlin)
- **Potential Value Of Retired Generating Sites** (Mr. LaCapra)
- **"Uncertainty" Of Current Decommissioning Estimating Methods And Experience Available to Evaluate Decommissioning Cost Estimates** (Mr. Biewald)

II. FOSSIL DECOMMISSIONING

Q. Do you agree with Mr. Kollen's characterization of TLG's fossil decommissioning studies as "inherently speculative and uncertain"?

A. No, not with the current site-specific cost estimates. The technology and knowledge required to dismantle a fossil-fired station is available today. Proper application of these "resources" reduces the level of uncertainty in planning and, consequently, in cost estimating. Some uncertainty in the ultimate cost of decommissioning is unavoidable until the facility is ultimately shutdown and its final condition determined. Decommissioning plans and estimates are based upon known factors and conditions. "Unknowns" will most likely add to the cost of decommissioning. Consequently, it is unlikely that decommissioning costs are overestimated. The greater probability is that they are underestimated.

Q. Do the retirement dates assumed in the TLG dismantling studies affect the cost calculated to dismantle a fossil-fired station?

A. No. The dismantling studies represent the cost to dismantle the station in current dollars as it is presently constructed and configured, with current technology and under existing regulations. Life extension or premature closure of a fossil-fired facility would not substantially alter the cost to dismantle the structures or remediate the site.

Q. Mr. Kollen cites Commission precedent as consistently rejecting fossil decommissioning costs "because the costs are not known and measurable." Would you agree that the costs are not known or measurable?

A. No. Currently there is sufficient experience in the dismantling of entire fossil-fired stations, as well as the dismantling of major components of such stations as part of unit retrofits and maintenance, to accurately estimate site remediation costs. Public Service Electric & Gas Company and Florida Power & Light Company have actively dismantled retired fossil-fired stations.

Q. Has the Commission previously recognized the need for dismantling conventional structures?

A. Yes. As early as 1985, in Pa. P.U.C. v. Pennsylvania Power Company (Docket R-850267), the Commission evaluated the need to dismantle the non-radioactive portions of nuclear units and decided to include the costs of dismantling these structurally compromised, non-contaminated structures as part of the nuclear decommissioning costs. The Commission determined that such facilities will have to be dismantled or removed in order to adequately protect the public and meet applicable safety requirements imposed by local building ordinances. Thus, in Pa. P.U.C. v. Pennsylvania Power Co., 67 Pa. P.U.C.

91 (1988), the Commission stated: "Given current requirements both in Ohio and Pennsylvania regarding abandoned structures, the prudent course is to plan for the removal of <u>all</u> the structures." The Commission recognized that large operating plant structures even if not radiologically contaminated created a "special" threat to public health and safety that merited an exception to its general policy of not funding prospective net negative salvage of utility property.

Q. Why is this extension of the definition of "special threat to public health and safety" important?

A. If retired fossil-fueled power plants are not secured and maintained with respect to guarding the site, roof repair, painting, vegetation and animal control, etc., the buildings and site will become a hazard to the public health and safety. Asbestos insulation will fall away from the piping and components and become airborne, corrosion of structural steel support members will weaken the buildings, and corrosion of steel floor gratings will make them unsafe for any personnel traffic, much less for use in future dismantling activities.

Accordingly, these conditions represent a "special threat to public health and safety" that justify dismantling of fossil-fired plant structures. The cost of this dismantling should be handled in the same manner as the nuclear decommissioning expense, i.e., properly funded.

Q. Why should the Commission approve the funding of dismantling of fossil-fired stations in advance of the work being performed?

A. The establishment of a fund or reserve for fossil decommissioning will allow PECO to proceed in an expeditious manner once the stations are retired. The longer these units lay dormant, the more difficult and hazardous the process of dismantling becomes. As previously explained asbestos becomes friable and the structural integrity of the building is compromised. The cost of dismantling increases because of these factors and increasingly stringent regulation from state and federal agencies such as EPA, OSHA and the Department of Labor. Prompt dismantling is the most cost-effective solution.

Q. Does the dismantling of fossil-fired stations involve any extraordinary safety problems?

A. Yes. Work in abating and removing asbestos, PCBs, acids and caustics is hazardous work for which trained professional companies must be employed. Asbestos removal work is, in many respects, <u>more</u> hazardous than radioactive equipment removal work. Federal and state regulations require workers to have complete medical examinations including electrocardiograms, x-rays examinations, and pulmonary function tests. All workers must successfully complete 32 hours of asbestos removal training (40 hours for supervisors, additional 8-hour courses for asbestos sampling technicians). Workers are required to wear full protective clothing (coveralls, boots, gloves, caps), use air purifying or supplied air masks for respiratory protection, and carry and monitor portable air samplers. All work must be performed in double-walled tents maintained under negative pressure. Upon leaving an asbestos work area, workers are required to remove their protective clothing (but not their respirator) and shower to remove residual asbestos fibers. After showering, they enter a third enclosure to remove the respirator and change into street clothes. This process is repeated at least four times a day, considering the need for breaks and lunch. All materials brought out of the work area (asbestos materials, tools and equipment) and into a "cargo area" must be double bagged, stripped of the outer bag in the cargo area, and rebagged for disposal or storage.

Similarly, workers involved in cutting lead-painted surfaces by any cutting technique are required to have separate, but similar training for worker safety and lead contamination control.

In summary, this work is hazardous and "special" from the perspective of its potential impact on public health and safety. Accordingly, it should be handled from a financial planning standpoint in the same manner as nuclear power plant decommissioning; namely, by recognizing that it will be done and properly compensating utilities for these costs.

Q. Are the number of assumptions used in the estimates indicative of the overall accuracy of the reported costs?

A. No. TLG has made it a practice to clearly identify the bases for its estimates to eliminate any chance for confusion or misinterpretation. We have attempted to identify every major assumption that can affect the cost estimates either in a positive or negative manner. Clearly identifying each and every assumption minimizes the degree of speculation as to what is, or is not, included in the estimate. Mr. Kollen simply missed the point of our care for accuracy in these estimates. The number of assumptions identified as the basis for an estimate is an affirmation of the validity of an estimate, not a weakness.

Q. Does the future use of a site have a bearing on the extent of site restoration assumed in the current decommissioning cost studies?

A. Whether or not new generation facilities are constructed and operated at the site in the future does not alter the assumptions in PECO's decommissioning studies. Generation technology continues to evolve. It would be unreasonable to assume that facilities developed as much as 40 to 50 years ago will be able to adapt to the prototype generating plant of the future. It simply is not prudent to expect that it would be technologically or economically feasible to mold a new, state-of-the-art generating plant to fit existing, antiquated facilities and equipment not to mention the asbestos removal concerns discussed earlier.

Q. Should collection of fossil decommissioning costs be deferred until PECO identifies a plan for ultimate reuse of the site(s)?

A. It is neither realistic nor equitable to postpone recovery of such costs. Decommissioning activities must take place, and it is appropriate to make basic assumptions about the usefulness of the facilities which will have expended their useful life during the operation of a power plant. However, it is impractical, indeed not feasible, for utilities -- or other property owners, for that matter -- to develop detailed, specific site plans for 30 to 40 years into the future. The uncertainty in forecasting detailed, specific site plans so far into the future simply renders such an undertaking impractical.

III. CONTINGENCY

Q. What is meant by the term "contingency" as used in cost estimating?

A. In simplest terms, "contingency" is equivalent to "experience." Unit factors used to estimate work costs tend to be ideal numbers that must be adjusted to fit the real world of experience. Professional cost engineers use the term contingency to refer to these predictable costs confirmed through experience. TLG considers contingencies to be an integral part of the estimating methods it employs. Accordingly, TLG always recommends inclusion of a contingency in a decommissioning cost estimate.

Q. Is the application of contingency a long established approach to cost estimating?

A. Yes. The NRC standard formula for calculating decommissioning costs for nuclear units provides for contingency, and cost engineers routinely include contingency dollars in project cost estimates.

Q. What level of contingency is incorporated within the decommissioning cost estimates relied upon by the NRC for rulemaking?

A. A 25% contingency factor was applied to the costs estimated for decontaminating and dismantling the nuclear units used as model plants in the estimates prepared for the NRC. While their across-the-board contingency is certainly appropriate, in our studies we have used even more precise line-by-line contingencies.

Q. Did TLG, as Mr. Kollen contend, use contingency to address future uncertainties?

A. Absolutely not. Contingency, as used within the TLG's estimates, addressed events occurring during the decontamination and dismantling process. Contingency is used in the estimation of decommissioning and decommissioning related activities regardless of the schedule for performance, i.e., *contingency (in itself) does not offer protection against* evolving costs and would be equally prudent on an estimate being planned in the near term as it would for future work.

Q. Mr. Catlin eliminates contingency in his calculations of fossil decommissioning costs on the basis that the Commission had eliminated contingencies built into PP&L's nuclear decommissioning cost estimates in Docket No. R-00943271. Do you agree with this rationale?

A. No. Precedent, while appropriate in one instance, may be inappropriate given additional considerations or evidence to the contrary. Thus, in Pa. P.U.C. v. Pennsylvania Power Company (Docket R-850267), the Commission approved TLG's cost estimates for the Beaver Valley Unit 1 and Perry 1 nuclear power plants with the full knowledge that the estimates included a 25% contingency to account for unanticipated difficulties which may be experienced. The Commission did not characterize contingency, in that context, as speculative or its inclusion as inappropriate.

The PP&L ruling needs to be considered in light of my comments in my direct testimony regarding the ALJ's and the Commission's misunderstanding of the nature and purpose of contingency.

Q. Is contingency generally recognized by regulators as a necessary component of a cost estimate?

A. Yes. Contingency is recognized, and its inclusion approved by the Nuclear Regulatory Commission, Federal Energy Regulatory Commission, and numerous state commissions including Alabama, Arizona, California, Connecticut, Florida, Iowa, Louisiana, Michigan, Minnesota, Missouri, North Carolina, New Hampshire, Texas, Virginia and Wisconsin. The California Public Utility Commission mandated a 50 percent contingency for the Diablo Canyon estimates. Southern California Edison Company uses an approved 40 percent contingency in its estimates for the San Onofre nuclear units. While the level of contingency can vary, its inclusion is both prudent and financially responsible.

Q. Are the decommissioning estimates for PECO's nuclear units inflated through the use of contingency, as Mr. Gill contends?

A. No. Contingency funds are expected to be fully expended throughout the program. It is not a "safety factor" or "cushion." An estimate without contingency, or from which contingency has been removed, can disrupt the orderly progression of events and jeopardize the financial success of the project.

Contingency is not an overstatement of costs, but a recognition of actual costs incurred in recent experience with decommissioning activities that were not foreseeable in advance. TLG's actual field experience on large power plant decommissioning projects including Shippingport, Pathfinder, Shoreham and Yankee Rowe have shown that contingency dollars are needed to cover unforeseen costs of events that occur in the field, as I described in my direct testimony.

Q. Does contingency provide protection against future inflation and escalation of the estimates to decommission?

A. No, as I have stated previously, contingency in itself does not offer protection against evolving costs, including inflation and escalation of the estimates to decommission. In addition, it should be noted that the Company's use of a 10% contingency is below that recommended by TLG in its site-specific decommissioning cost studies. Funding to this lower level will ultimately produce a shortfall in the collections needed to decontaminate and dismantle PECO's generating units, based upon the total cost calculated by a site-specific estimate.

Q. Why is contingency, as applied within the decommissioning cost estimates, appropriate and justified?

A. The basis for the inclusion of contingency is provided within my direct testimony. TLG's experience as the largest subcontractor in the decommissioning of the Shippingport Atomic Power Station provided a test for its cost estimating methodology including the use of contingency factors. All work on this program was competitively bid and required the highest degree of accuracy in estimating individual activity costs. (TLG relied upon this same cost estimating methodology in preparing its bids for Shippingport that it used in developing the decommissioning estimates for the PECO units.) Not only was TLG a successful bidder at Shippingport, but it was the only subcontractor to complete its assigned task(s) within budget and on schedule. This success provided field confirmation of TLG's empirical data base used to produce its estimates.

The accuracy of TLG's estimates have also been confirmed in decommissioning activities undertaken at Yankee Rowe, Trojan, Shoreham, Pathfinder, and Rancho Seco. Each estimate contained a level of contingency appropriate with the activities identified for the specified decommissioning program.

IV. POST-SHUTDOWN EARNINGS

Q. Messrs. Catlin and Kollen contend that earnings on the nuclear decommissioning trusts accruing after the shut down of the Company's nuclear plants should be taken into consideration in calculating the Company's annual decommissioning accrual. Would you like to comments upon that proposal?

A. Yes, I would. Current NRC rules require a nuclear decommissioning trust fund to be fully funded in the amount necessary to terminate the NRC license at the time the plant is shut down. Consequently, to comply with that requirement, the Company needs to calculate its accruals without regard to post-shutdown earnings on the decommissioning trust funds. I should note, however, that the NRC has approved for issuance a Proposed Rule that would permit recognition of post-shut down trust fund earnings at an imputed real rate of return of 2% or such other rate of return as is approved by the licensee's rate setting authority to determine the decommissioning expense included in its cost of service. The Proposed Rule has not yet been published in the Federal Register. Upon publication, there will be an opportunity for comment and, thereafter, continued review by the NRC. Unless and until the Proposed Rule is made final, it would be appropriate to calculate PECO's decommissioning funding obligation on the basis of existing NRC requirements.

V. COST ESTIMATING AND DECOMMISSIONING TECHNOLOGY

Q. Do you agree with Mr. Biewald's assessment that "It is not possible now to produce an accurate estimate [of] the cost of decommissioning PECO's nuclear units"?

A. No. Mr. Biewald contends that "The dismantlement process itself involves considerable uncertainty, as experience dismantling commercial nuclear reactors is limited to smaller units or special cases such as the Shoreham unit in Long Island, which operated only at low power for a short period of time. Dismantling a full-scale nuclear unit that has operated for many years will present new challenges." Mr. Biewald misperceives the facts and his contention is without merit.

Q. Do you agree with Mr. Biewald's assessment of the state of decommissioning technology as related to the uncertainties in estimating costs?

A. No. The decommissioning of the Shippingport Atomic Power Station demonstrated "large scale" decommissioning technology. In addition, Mr. Biewald has chosen to ignore the very large data base accumulated from decommissioning related activities. Steam generators have been removed (e.g., at North Anna, Surry, Turkey Point, Millstone 2, Yankee Rowe, Trojan, Point Beach, Palisades, Robinson), reactor internals disassembled and segmented (e.g., at Shoreham, Millstone 2, St. Lucie, Yankee Rowe), reactor recirculation piping replaced (Vermont Yankee, Nine Mile 1), etc. Certainly, one can expect continued advances in technology, but new technology will not necessarily decrease uncertainty and does not guarantee cost savings. In addition, Mr. Biewald's "largest uncertainty" (waste disposal) is not a consequence of the technology of waste disposal, but of political concerns.

Q. Mr. Biewald uses an escalated 1975 estimate for decommissioning a large commercial reactor to support his claim that decommissioning cost estimating "is not a mature, stable undertaking." Is this a valid example?

A. No. Decommissioning costs consist of three major elements of costs as properly identified by the NRC in its Decommissioning Rule (10 CFR Part 50.75(b)(2). These are labor, energy and burial costs. The percentages of each element are specific to each plant and estimate. The appropriate inflation factor for labor, energy and burial differ significantly, and burial represents the largest difference of the three. Using a single inflation factor based on a national Consumer Price Index or other similar factor is wrong and misleading.

Mr. Biewald ignores economic factors beyond general inflation in his manipulation of data. For example, disposal costs for low level radioactive waste in 1975 were less than $2 per cubic foot for burial at the Barnwell, South Carolina facility. Today, costs at this facility exceed $300 per cubic foot. Estimates performed today would have to recognize this increase. However, the increase in waste disposal costs does not, by any means, reflect upon the adequacy of the estimating tools or maturity of the estimating techniques used in assembling a decommissioning estimate. The accuracy of current estimating tools can be shown in their ability to accurately predict the cost of decommissioning and decommissioning related activities that have been accomplished to date. Based upon these criteria, the ability to estimate and accomplish large-scale decontamination and dismantling activities within budget has been demonstrated.

Q. Would you expect, as Mr. Biewald suggests, decommissioning costs to contain the same "institutional uncertainties" evident in nuclear power plant construction?

A. No. The trends of cost overruns exhibited in nuclear plant construction costs are not currently seen in recent decommissioning projects. Furthermore, construction costs of the 1970's and 1980's were plagued with NRC design and backfit changes that caused havoc with construction budgets and schedules. During the late 1970's, plants under construction were experiencing construction interest rates approaching 20 percent. This fly-up in interest rates was a significant cause of plant construction costs exceeding their budgets, considering that the interest was almost 60 percent of the total costs.

Construction activities require each installed component, each weld, each startup test to be inspected and approved/verified with appropriate QA documentation to demonstrate full compliance with its safety function. In decommissioning, once a component or pipe is cut, you are done. There is no going back to reweld it to cut it in a better manner. Accordingly, the problems facing construction costs are not likely to be encountered in decommissioning.

Q. Do you agree with Mr. Biewald that large increases in the estimated cost for decommissioning indicate a high degree of uncertainty in the current decommissioning cost estimates which are developed in the same manner?

A. No. The large increases reflect changes in scope or inflationary factors which are accounted for in periodic updates to the estimate(s). They are not necessarily indicative of uncertainties in the estimate.

VI. LAND VALUE

Q. Mr. LaCapra provides an estimate of the potential value of PECO's generating sites. Did TLG consider the market value of existing generating facilities and the associated property on which they are located?

A. No. The land and infrastructure associated with the fossil generating facilities was not considered to have a net value in the fossil dismantling studies prepared by TLG. The sites are not assumed to be completely restored (i.e., greenfield), with subsurface foundations and buried plant services abandoned. In addition, concrete rubble generated in the dismantling process is assumed to be used as fill for below-grade voids. Ponds will be closed and stabilized, however, their presence and the requirement for continuing monitoring restrict the future use of the site and any potential commercial value.

It is important to note that the dismantling studies addressed only the costs to remediate the primary generating facilities. No allowance was included for the cleanup of possible site areas contaminated by fuel oil, PCBs or other hazardous materials that may be present in the soil from years of operation.

The land and infrastructure associated with the nuclear generating facilities were also not considered to have a net value in the decommissioning studies prepared by TLG. Similar to the assumptions used in the fossil studies, the nuclear sites are not assumed to be completely restored (i.e., greenfield), with subsurface foundations and buried plant services abandoned. Concrete rubble generated in the dismantling process was assumed to be used as fill for below-grade voids. A soil cap was placed over the open foundations to conceal the exposed rebar and concrete debris, and provide a medium for vegetation (for erosion control). Contamination is removed to residual levels, however, the nuclear legacy of the site will, more than likely, depress its commercial value.

The facility's infrastructure degrades without continual maintenance. Unless the site is redeveloped shortly after release of its NRC license, the value in reusing plant facilities quickly diminishes. For example, following NASA's development of TVA's abandoned Yellow Creek nuclear power plant for its Advanced Solid Rocket Motor program, a Lockheed spokesman was quoted as stating: "[t]he abandoned nuclear power plant contributed little to the NASA project. Some of the power and water infrastructure was used but had to be reconstructed after eight years of neglect."

Q. Does "transmission access, with transportation of fuel, and with appropriate zoning" add to the value of the property?

A. Not necessarily. The property only has value if sold or reused for new generation. The suitability of the current sites for future generation has not been determined and will depend upon the generating technologies available in the future, local load growth and demand, and the development of adjacent property. For example, combustion turbines may or may not require the infrastructure of an existing generating site. Typically, this equipment is optimally situated closer to the load or demand points. An existing generating site is unlikely to be the most advantageous location, depending upon the redistribution of industry and commercial customers and load growth in the intervening years, i.e., since the original generating plant was constructed.

Q. Does this conclude your rebuttal testimony?

A. Yes.

R0097395?

PECO STATEMENT NO. 9-R

Phila 10/14, 15/16/97
B. Holbert

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

JAMES I. WARREN

RESPONDING TO OPPOSING PARTY TESTIMONY

WITH RESPECT TO SFAS 109 REGULATORY ASSET

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF JAMES I. WARREN

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James I. Warren. My business address is 40 West 57th Street, New York, New York 10019.

Q. ARE YOU THE SAME JAMES I. WARREN WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to rebut the contention asserted by both Messers. Catlin and Kollen that PECO Energy Company's ("PECO" or the "Company") FAS 109 asset should not be reflected on a "nominal dollar" basis, as the Company has proposed. They assert that it should be discounted to reflect the weighted average remaining useful life of the Company's generating plant (approximately 27 years).

Q. WHAT IS YOUR CONCLUSION REGARDING THIS PROPOSAL?

A. This proposal is erroneous. The Company has provided all possible time value benefits produced by its FAS 109 asset to its customers. Imposing a discount in such a situation would be illogical and economically unjustified.

Q. WILL YOU EXPLAIN AGAIN EXACTLY WHAT IT IS THAT PECO'S FAS 109 ASSET REPRESENTS?

A. As I stated on page 14 of my direct testimony, by claiming on its tax returns the beneficial treatment of certain items of income and expense available to it under the tax law, PECO effectively "borrowed" funds from the federal government. It then passed (or "flowed through") the proceeds of these "loans" on to its customers through the rate process, resulting in lowered rates at the time. However, all parties to this preceeding recognize that these "loans" have to be repaid in the future. The FAS 109 asset represents the regulators' promise that they will cause the Company's customers to restore to the Company (again, through the rate process) the benefits they previously received in order to fund the repayment of the "loans" by the Company to the federal government.

Q. WHAT IS THE TIME FRAMEWORK FOR THIS RESTORATION BY PECO'S CUSTOMERS?

A. In the normal course of events, PECO's customers are called upon to restore the benefit at the time that the Company must repay the "loans."

Q. UNDER THESE CIRCUMSTANCES, DOES THE COMPANY DERIVE ANY VALUE FROM THE USE OF THE FUNDS?

A. If, in fact, the customers restore the benefit only at that point in time when the Company repays the "loans," the Company derives no benefit from the use of funds. The money comes in and goes out concurrently. In such a situation, the customers have received the full benefit of the governmental "loan" the entire time it is outstanding. The Company receives no benefit from it whatsoever.

Q. IF THIS WERE THE CASE, WOULD IT BE APPROPRIATE TO DISCOUNT THE FAS 109 ASSET?

A. Absolutely not. Because the Company would not have the use of any funds prior to the time of the related tax expenditure, there is no logic or support for present valuing.

Q. IF, ON THE OTHER HAND, PECO'S CUSTOMERS WERE TO RESTORE THE PREVIOUSLY RECEIVED BENEFITS PRIOR TO THE TIME WHEN THE COMPANY IS REQUIRED TO REPAY THE RELATED "LOAN", WOULD IT THEN BE APPROPRIATE TO DISCOUNT THE FAS 109 ASSET?

A. In the event that PECO's customers were to restore the benefit in advance of the Company's related tax expenditure, then the Company would have the use of the funds (*i.e.*, the governmental "loan") between the time of the restoration and the time of "loan" repayment. For that period of time, it would be in the same position as if it had not passed the proceeds of the loan through to the customers (*i.e.*, as if it had normalized). Were this so, there is some rationale to support a reduction of the FAS 109 asset to reflect the availability of this cost free capital. This would be the economic equivalent of providing a rate base reduction for accumulated deferred federal income taxes ("ADFIT").

Q. IN LIGHT OF THE ABOVE, IS THE PROPOSAL TO DISCOUNT THE FAS 109 ASSET OFFERED BY MESSERS. CATLIN AND KOLLEN APPROPRIATE?

A. No. Their proposal is only even arguably appropriate if customers provide the Company with the money to repay the governmental "loan" prior to the time the Company is obligated to pay it back. That, as I will show, is not the case. For analytical purposes, it will be helpful to consider the FAS 109 asset in three parts: (1) the "gross-up" portion, (2) the portion related to stranded generating plant and (3) the portion related to non-stranded generating plant. With respect to the "gross-up" portion, it is a mathematical certainty that the customer restoration will exactly coincide with the necessity to repay the "loan." Therefore, no discounting is appropriate. Similarly, with respect to the portion of the FAS 109 asset that relates to stranded generating plant, the customer restoration and the loan repayment will be simultaneous. Again, no discounting is appropriate. With respect to the portion of the FAS 109 asset that relates to non-stranded generating plant, there will, in fact, be a "pre-funding." However, PECO has reflected this benefit appropriately by reducing the amount of stranded generating plant. In this way, the customers have received the full present value benefit of the "pre-funding." Once more, no discounting is appropriate.

II. <u>THE ANALYTICAL STRUCTURE</u>

Q. WHAT FACTORS ARE KEY IN EVALUATING THE PROPRIETY OF THE PROPOSAL OFFERED BY MESSERS. CATLIN AND KOLLEN?

A. There are two such factors - the timing of the collection of the FAS 109 asset (*i.e.*, the "restoration") and the timing of the repayment by the Company of the governmental "loans."

Q. IS THERE ANY CONTROVERSY OR UNCERTAINTY WITH REGARD TO THE TIMING OF THE FAS 109 ASSET COLLECTION?

A. No there is not. Under the Company's proposal, the FAS 109 asset will constitute a component of the CTC and will be recovered ratably over seven years. Thus, there is no dispute over the time framework for the "restoration."

Q. WHAT CONTROLS THE TIMING OF REPAYMENT BY THE COMPANY OF ITS GOVERNMENTAL "LOANS"?

A. This is described in the accounting pronouncement FAS 109 itself. Paragraph 11(d) of that standard explains:

> The cost of an asset (for example, depreciable personal property) may have been deducted for tax purposes faster than it was depreciated for financial reporting. *Amounts received upon future recovery of the amount of the asset for financial reporting will exceed the remaining tax basis of the asset, and the excess will be taxable when the asset is recovered.* (Emphasis added).

It is the recovery of the cost of the underlying asset reflected on financial statements which triggers the "loan" repayment.

Q. WILL YOU PROVIDE A SIMPLE EXAMPLE?

A. Yes. Assume PECO purchases an asset for $500 in Year 1. In that year, PECO charges its customers for $100 of "book" (*i.e.*, regulatory) amortization with respect to the asset but deducts the entire $500 cost on its tax return. PECO thereby enjoys a reduction in its tax liability of $140 ($400 X 35%) on account of the liberalized tax treatment afforded that asset. This, then, is the amount of the governmental "loan." Assume further that PECO flows the benefit of this tax deduction through to its customers. Rates in Year 1 will be reduced on account of the tax benefit of the "extra" $400 deduction available to PECO under the tax law by $215 [$140/(1-35%)]. Under FAS 109, PECO would reflect a $215 FAS 109 asset on its balance sheet. This amount can be viewed as consisting of the principal of the loan ($140) and the "tax gross-up" ($75).[1]

[1] When the $215 is restored to PECO by its customers through the rate process, PECO will pay tax of $75 ($215 X 35%) on the receipt of the restoration and use the remaining funds ($140) to pay off the "loan.".

In Year 2, PECO again charges its customers $100 of "book" amortization with respect to the asset. However, because the cost of the asset was entirely deducted for tax purposes in Year 1, in Year 2 the asset is incapable of producing additional tax deductions. As a consequence, when PECO recovers the $100 in rates on account of amortization, it will incur a $35 tax ($100 X 35%). This imposition of tax represents a partial repayment of the $140 "loan" that was extended in Year 1. In order to pay back this portion of the "loan," the customers must restore $53 of the prior rate reduction. Upon receipt of this amount, PECO will pay a $18 tax ($53 X 35%) and will apply the remaining $35 to the "loan" repayment. The identical situation will ensue each year from Years 3 through 5.

III. THE TAX GROSS-UP PORTION OF THE FAS 109 ASSET

Q. WHAT DOES THIS EXAMPLE ILLUSTRATE ABOUT THE TIMING OF THE "LOAN" REPAYMENT?

A. This example illustrates two important points. The first is that the portion of the FAS 109 asset that is attributable to the "tax gross-up" is used to pay tax on the receipt of the FAS 109 asset itself. Thus, from a timing perspective, the "tax gross-up" portion of the FAS 109 asset **cannot** be collected prior to the necessity to pay the associated tax liability. It is the collection of the FAS 109 asset itself that triggers the payment of the tax. Thus, the "tax gross-up" portion of the restoration is immediately used to fund a tax liability and cannot by its nature produce disposable funds. There can, therefore, be no possible justification for discounting the "tax gross-up" portion of the FAS 109 asset under any circumstances.

Q. HOW MUCH OF PECO'S FAS 109 ASSET BALANCE REPRESENTS THE "TAX GROSS-UP" PORTION?

A. 35% of PECO's FAS 109 asset balance is attributable to the "tax gross-up." In the example above, the $140 of tax benefit flowed through required a $75 "tax gross-up." Thus, of the $215 FAS 109 asset created in the example above, 35% constituted "tax gross-up."

IV. THE PORTION OF THE FAS 109 ASSET RELATING TO STRANDED GENERATING PLANT

Q. WHAT IS THE SECOND POINT ILLUSTRATED BY THE EXAMPLE?

A. The second point illustrated, and it is a critical one, is that the event that triggers the series of repayment obligations is the collection of the $100 of asset amortization in Years 2 through 5. **As described in FAS 109 itself, it is the recovery of the cost of the underlying asset the produces the relevant tax liability.**

Q. IN THE EXAMPLE ABOVE, WHAT IF, AFTER YEAR 1, THE REMAINING BALANCE OF THE ASSET WAS TO BE RECOVERED OVER TWO YEARS INSTEAD OF FOUR YEARS?

A. In this event, in Year 2 the Company would collect $200 due to amortization of the asset. This would produce a tax liability of $70 ($200 X 35%). To fund this liability, the customers would have to restore $107.50 of the FAS 109 asset. Were this to occur, the Company would pay a tax of $37.50 ($107.50 X 35%) on the restoration and would use the remaining $70 to fund the "loan" repayment due. The same process would ensue in Year 3.

Q. WHAT, THEN, IS THE EFFECT OF ACCELERATING THE RECOVERY OF THE COST OF THE ASSET?

A. Accelerating the recovery of the cost of the asset accelerates the "loan" repayment requirement and, thus, the necessity to recover the FAS 109 asset. It does not cause the restoration to precede the necessity to repay the "loan."

Q. WHAT WOULD HAPPEN IF, DESPITE ACCELERATING THE RECOVERY OF THE ASSET COST, THE COMPANY WAS ALLOWED TO RECOVER ITS FAS 109 ASSET OVER THE ORIGINAL FOUR YEARS?

A. If this were to occur, the Company would be economically prejudiced by having to repay the entire governmental "loan" during Years 2 and 3 while, during those same two years, the customers would restore only one-half of the related benefit.

Q. WOULD DISCOUNTING THE FAS 109 ASSET TO REFLECT A FOUR YEAR AMORTIZATION AND ALLOWING RECOVERY OF THE DISCOUNTED AMOUNT OVER TWO YEARS PRODUCE THE SAME DETRIMENT AS THE ONE DESCRIBED ABOVE?

A. Yes it would.

Q. IN WHAT WAY IS THE SITUATION DESCRIBED ABOVE ANALOGOUS TO PECO'S SITUATION WITH RESPECT TO ITS CTC FILING?

A. The effect of designating a portion of the cost of PECO's generating assets as stranded and incorporating them into the CTC charge to be recovered over seven years is to accelerate the recovery of the stranded portion of the cost of those assets. This is exactly analogous to the situation described above. This cost recovery acceleration accelerates the necessity to repay the governmental "loans." The recovery of the related FAS 109 asset must also be accelerated simply to maintain financial neutrality.

Q. WHAT WOULD HAPPEN IF THE FAS 109 ASSET RELATED TO THE STRANDED PORTION OF THE GENERATING PLANT IS DISCOUNTED TO REFLECT THE 27 YEAR PERIOD THAT MESSERS. CATLIN AND KOLLEN PROPOSE?

A. The Company will be denied a portion of the funds that it needs to repay its governmental "loans" when those repayments are required. From an economic perspective, it would be the same as if the Company was required to repay its loans over the seven year CTC period while its customers restored the related benefit over 27 years. Messers. Catlin and Kollen propose the imputation of a time value benefit that does not, in fact, exist. The discounting they propose has no economic logic.

V. THE PORTION OF THE FAS 109 ASSET RELATING TO NON-STRANDED GENERATING PLANT

Q. WILL YOU DESCRIBE THE SITUATION WITH RESPECT TO THE NON-STRANDED PORTION OF THE GENERATING PLANT?

A. Yes I will. Because these costs are not incorporated into the CTC, this proceeding will not effect an acceleration of their recovery. At this point in time, it appears that these costs will proceed to be recovered from the competitive marketplace over the 27 years suggested in the direct testimonies of Messers. Catlin and Kollen. The recovery of the FAS 109 asset which relates to these costs[2] over the seven year CTC period will effect a customer benefit restoration in advance of the necessity to repay the related governmental "loan." Thus, the Company will have the use of these funds for a period of time, just as it would have had the all tax benefits been normalized originally. The amount recovered during the seven year CTC period will diminish over the succeeding 20 years.

[2] Exclusive, as previously indicated, of the "tax gross-up."

Q. HOW HAS PECO REFLECTED THE AVAILABILITY OF THESE FUNDS IN ITS FILING?

A. The Company has reduced its stranded investment by the present value of this positive stream of cash. Mr. Cohn's rebuttal testimony specifically describes and explains the mechanisms used to accomplish this.

Q. WHAT IS THE ECONOMIC EFFECT OF THIS TREATMENT?

A. As regards the portion of the FAS 109 asset relating to non-stranded generating plant, PECO's customers have received the economic equivalent of the proposal put forth by Messers. Catlin and Kollen. Instead of discounting the FAS 109 asset, the Company has "discounted" its stranded plant costs. The effect is the same.

Q. WHAT WOULD BE THE IMPACT OF ADOPTING MESSERS. CATLIN AND KOLLEN'S PROPOSAL AS TO THIS PORTION OF THE FAS 109 ASSET?

A. In light of the incorporation of the economic benefit they describe into the computation of stranded plant, the implementation of their proposal would effect a "double counting" of the benefit. This is, obviously, unwarranted.

VI. CONCLUSION

Q. WHAT THEN IS YOUR CONCLUSION WITH RESPECT TO THE SUGGESTION THAT PECO'S FAS 109 ASSET BALANCE BE DISCOUNTED TO REFLECT THE 27 YEAR REMAINING LIFE OF ITS GENERATING PLANT?

A. I believe this proposal to be without economic foundation. The Company has provided to its customers the full, appropriate measure of benefit associated with its tax posture.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.