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PECO STATEMENT NO. 6-R

Phila 10/14,15/97

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

WILLIAM H. HIERONYMUS

Regarding Updated Market Price Forecast
Using GE MAPS, Assessing Testimony of Intervenors
Regarding Market Price Forecasts,
and Rebutting Other Issues Raised By Intervenors
Related to Stranded Costs.

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TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your full name and business address.

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

Q. Have you submitted testimony previously in this proceeding?

A. Yes. I submitted PECO Statement No. 6 and accompanying Exhibit Nos. WHH-1 to WHH-5. My background and qualifications are set forth in Exhibit No. WHH-1 to that Statement.

Q. What is the subject area of your testimony?

A. I am providing a forecast of the market price of energy for PECO. The future market price of energy is a key ingredient in determining the net stranded generating cost for PECO. The higher the market price, the lower stranded costs will be. The lower the market price, the higher stranded costs will be.

Q. What is the structure of your rebuttal testimony?

A. My rebuttal testimony is divided into three sections. First, I provide an updated forecast of the market price of energy using the General Electric Multi-Area Production Simulation Program ("GE MAPS"). This forecast combines updated information regarding certain input assumptions and fully integrates any valid suggestions made by the intervenors.

Second, I respond to and rebut the testimony of certain intervenors' witnesses regarding market price issues. Specifically, I will address the testimony of PAIEUG witness Randall Falkenberg and OCA witnesses Richard La Capra and Douglas Smith. My testimony responds to criticisms made by these witnesses regarding the GE MAPS model and the input assumptions used, and independently evaluates the models and input assumptions used by the intervenors. Because PAIEUG (through Mr. Falkenberg) touches on almost all of the critiques offered by any other party, I have focused my remarks principally on the PAIEUG testimony.

Third, I rebut certain other specific issues raised by various witnesses. Regarding the issue of proposed "adjustments" to PECO's stranded cost recovery, I respond to the testimony of OSBA witness Brian Kalcic. Regarding the use of auctions to derive the value of stranded generation assets, I address the testimony of David Schoengold, a witness for the Environmentalists. Regarding the subject of the effects of stranded cost recovery on competition in the utility industry, I rebut the testimony of Indianapolis Power & Light witnesses John Brehm and Wilbur Lewellen.

<u>II. UPDATED MARKET PRICE FORECAST</u>

Q. What is the basis for the updated market price forecast you are presenting?

A. Like my analysis in PECO Statement No. 6, my current analysis is made using the GE MAPS model. As before, I have modeled PJM, NYPP, NEPOOL, and imports from ECAR. My model continues to use a PJM dispatch that incorporates transmission constraints. It utilizes the coordinated central commitment and dispatch of generation in effect in PJM. The model allows recovery of negative net cycle costs.[1] It continues to project that generation will be bid into the power exchange at incremental costs.

Q. How does your current analysis differ from the analysis contained in PECO Statement No. 6?

A. We have made several changes. These changes are primarily in response to intervenors' comments. The changes also reflect updated information and relatively minor changes based on further review of my initial assumptions. The main changes are:

1/ Negative net cycle costs are start up and no load costs exceeding amounts recovered as operating profits in the energy market during the day, which I also have referred to in my direct testimony as uplift payments.

- I have revised fuel prices to incorporate the updated Spring/Summer 1997 *DRI/McGraw-Hill fuel forecast.*

- I have derived minimum load incremental heat rates based on EIA Form 860 full load heat rate data preferred by the OCA and PAIEUG. I should stress, however, that I continue to use incremental heat rates and no-load costs for dispatch and price computation. I will show that using EIA Form 860 data has little effect on my results.

- I have increased the cost of the combustion turbines that set the capacity price in PJM, reflecting intervenor criticisms. My new combustion turbine cost is virtually the same as that presented by the OCA and PAIEUG.

- I have increased the fixed charge rate used in computing the price of capacity, reflecting intervenor criticisms that I have accepted. The new rate I am using is the OCA's proposed rate of 12.75 percent.

Q. Can you summarize your new results and compare them to the results contained in PECO Statement No. 6?

A. Yes. These results are summarized in Exhibit WHH-6.

I ran GE MAPS for 1999, 2004, and 2009 -- the same years that were modeled in my analysis in PECO Statement No. 6. A comparison of the average energy plus uplift plus capacity revenues -- the results that I am sponsoring -- for PECO's units during these years are presented in Table 1 below. These average revenues derived in my rebuttal analysis are lower than the projections presented in my original testimony. The primary factor leading to lower revenues is the use of the updated DRI fuel escalators that I discuss in a later section. Had I relied on the EIA escalation factors used by Mr. Falkenberg, the average revenues for PECO's units would have been even lower.

Table 1
Comparison of PECO's Average
Energy, Capacity, Plus Uplift Revenues
($/MWh)

	Direct Testimony	Rebuttal Testimony
1999	24.5	24.3
2004	37.6	36.9
2009	47.0	44.9

The change in average revenues presented in Table 1, together with changes in the discount rate assumed by PECO, cause the net present value of contribution margins (excluding negative values) to decrease from $2.17 billion to $1.79 billion.[2]

Q. **What is your main conclusion concerning the market price forecast that should be used in evaluating PECO's stranded generating costs?**

A. I conclude that my earlier forecast of market prices is a highly conservative measure of the most likely level of market prices. Taking into account updated fuel forecasts, those few intervenor criticisms I have accepted, and adopting some intervenors' data sources and estimates causes the projected market price to fall and, hence, the estimate of PECO's stranded costs to rise. Thus, my revised best estimate of market prices is below the estimate I sponsored in PECO Statement No. 6.

2/ These numbers are taken from the analysis discussed in the rebuttal testimony of PECO witness Thomas P. Hill, Jr. It is my understanding that these numbers include PECO's revision to its discount rate, from approximately 8.4 percent to approximately 8.7 percent.

III. CRITIQUE OF INTERVENORS' TESTIMONY REGARDING MARKET PRICE FORECASTS

A. Introduction and Summary

Q. Dr. Hieronymus, which of the intervenors have introduced models to forecast market price?

A. There are two principal intervenors' models. PAIEUG has introduced a model through Mr. Falkenberg. The OCA has introduced a model through Mr. Smith.

Q. What did you do to familiarize yourself with these models?

A. I and my representatives visited both Mr. Falkenberg and Mr. Smith and investigated the models' structure, input assumptions, and model outputs. In the following section, I discuss the input assumptions used in these models, as well as the working procedures of the models.

Q. Please summarize your conclusions regarding the model sponsored by PAIEUG witness Mr. Falkenberg.

A. There are four substantial errors that we have identified in PAIEUG's market price forecast:

- Mr. Falkenberg uses an incorrect and artificially high base year fuel price. For his base year fuel price, Mr. Falkenberg mistakenly relies upon accounting data rather than actual spot fuel prices.
- Mr. Falkenberg uses full load average heat rates as an input assumption. This assumption inappropriately biases his market price forecast. The PJM rules make provision for the use of incremental heat rates. Given the rules, the use of incremental heat rates in bidding also is economically efficient.
- Mr. Falkenberg incorrectly calculates the market price of capacity in attempting to forecast overall market value. Specifically, Mr. Falkenberg has ignored variable

- O&M costs, and grossly overestimated fixed O&M costs for the new capacity assumed to set the capacity market price. The fixed O&M costs calculated by Mr. Falkenberg are over 200 percent higher than the fixed O&M calculated by any of PECO's models and the OCA. This error results in an excessive valuation of PECO's capacity.

- Mr. Falkenberg's model itself contains several structural flaws and inadequacies. His model cannot perform unit commitment. Because his model is not able to track unit power levels from hour to hour, he incorrectly assumes infinite flexibility in the operation of units. Moreover, Mr. Falkenberg's model cannot determine transmission constraints. Finally, because Mr. Falkenberg apparently lacks the ability to estimate hourly power levels for NUGs or imports and exports, he incorrectly assumes that NUGs or imports and exports will not vary at any hour during the year. In short, the PAIEUG model lacks the reliability and sophistication to be used in making actual business decision in the electric utility industry, and provides a substantially invalid forecast.

Q. Please summarize your conclusions regarding the market price model presented on behalf of the OCA by Mr. Smith.

A. The OCA's model reflects several critical errors:

- Like PAIEUG, the OCA drastically overestimates the base fuel price used to forecast market value. The OCA makes the same error as PAIEUG, using accounting data rather than actual pricing data.

- The OCA model uses average as operated heat rates. However, the PJM rules require bidding based on incremental heat rates. Moreover, the use of average as operated heat rates substantially biases the OCA's market price forecast.

- The OCA model contains structural limitations and biases comparable to the problems with the PAIEUG model. Because the model lacks sensitivity regarding NUGs and imports and exports, the model does not reflect changes in these assumptions across all hours in the year. Moreover, the OCA inexplicably has chosen not to use the model's ability to model multiple interconnected areas and unit commitment, further reducing the validity of the model's results.

B. PECO's Methodology

Q. Have the intervenors provided any comments regarding PECO's overall methodological approach to computing net stranded generation costs?

A. Yes.

Q. Please summarize those comments.

A. The principal intervenors have explicitly endorsed PECO's overall methodology for calculating net stranded generation costs. (See, e.g., Baron Testimony (PAIEUG), p. 22; La Capra Testimony (OCA), p. 5; PAIEUG's response to interrogatory Set M-P.I., Q5; OSBA's response to interrogatory Set II, Q2). As a result, most of the intervenors' testimony consists of arguments regarding the appropriate input assumptions. The remainder of this section of my testimony addresses the intervenors' arguments regarding those assumptions.

C. GE MAPS Model

Q. What type of model is required to forecast the market price for utilities within PJM?

A. A reliable market price model should reflect, as closely as possible, the characteristics of the post-deregulation market. It also should allow market prices properly to reflect the effects of a unit's ability to start up and run, the costs of doing so (i.e., commitment and dispatch); the transmission system's ability to accept generation and to serve load (i.e., load flow/transmission); and the amount, duration and price of interregional flows of energy (i.e., imports and exports).

Q. How well does the GE MAPS model meet these criteria? That is, does the GE MAPS model address all of these issues?

A. Yes. As described in my earlier testimony, the GE MAPS model assesses unit commitment and dispatch, load flow/transmission constraints, and imports and exports. Most importantly, we have been able to use GE MAPS to model the market conditions that exist in PJM.

Q. You already have discussed the importance of incremental bidding. Why is it important to use a model architecture consistent with the proposed PJM rules?

A. Models that cannot dispatch on incremental bids, while also keeping track of no-load and start-up costs for separate recovery, force the modeler into the unfortunate position of relying on simplifications that either overestimate or underestimate PECO's revenues. For example, by using full load average heat rates, the OCA and PAIEUG models overstate PECO's revenues, thereby lowering recoverable stranded costs.

Q. What is unit commitment?

A. Unit commitment refers to one of the functions performed by the system operator. Prior to dispatch, normally a day ahead, a decision is made by the system operator as to which units will be run at a given time over the next day. In order to make this determination, the system operator will assemble information about likely customer load, units that are available to serve load, individual unit bids, and other information such as unit minimum up and down times. Based on this information, the system operator will determine which units to call on (i.e., commit) for the next day.

Q. Why is unit commitment an important modeling feature?

A. Models used by system operators to perform unit commitment must respect the flexibility limits of generators. Simple models that do not perform unit commitment, or do so without respecting the flexibility of units, will mis-state both unit output and revenues. By ignoring the inflexibility of units, the models will bias prices upward in low load hours.

Q. Why is proper transmission modeling important?

A. Failure to properly take into account transmission limits could cause a model to over-predict generation in low cost areas and under-predict it in high cost areas when transmission is constrained. Depending on how the cost of transmission constraints is allocated, it also can lead to mis-forecasts of the prices paid to individual generating stations.

Q. Why is it important to properly model imports and exports when forecasting prices?

A. For PJM, imports tend to depress prices. The level and role of imports and exports typically varies importantly by time period. For example, during off-peak periods, exports and imports will primarily affect the prices earned by baseload units; whereas during higher load hours, the import-export balance will affect the revenues of most units.

D. Deficiencies With the Intervenors' Models

Q. How well do the models presented by the intervenors meet the above-referenced criteria? That is, how well do the models presented by PAIEUG and the OCA address unit commitment, transmission constraints, and imports and exports?

A. Not very well. Addressing the PAIEUG model first, Mr. Falkenberg cavalierly dismisses as unimportant or even improper all elements of price determination that his model can not easily simulate.

Q. How does Mr. Falkenberg model unit commitment?

A. Mr. Falkenberg ignores the need for unit commitment and simply stacks units without regard for limits on their flexibility. This is convenient, since the model he uses cannot perform unit commitment. Specifically, Mr. Falkenberg assumes that, if available, a unit can be turned on at any power level in any hour, independent of all other hours. This implies that a unit, even nuclear units and super critical coal units, can be run for single hours (e.g., off at 10 a.m., on at full power at 11 a.m., and off again at noon). While this might seem more likely to bias his price forecast downward, the actual main effect is in the opposite direction. A substantial part of generation in night-time, low-load hours comes from inflexible units on minimum load. Such units do not set the market clearing price, but their output serves to reduce the need to run increasingly higher cost units to meet load.

Because Mr. Falkenberg's model simply sorts hours by level of load, it literally cannot tell night from day. Limitations on hour to hour changes in output and minimum loading requirements are ignored by Mr. Falkenberg. Therefore, his market price forecasts are biased and unreliable.

Q. How does Mr. Falkenberg model transmission constraints?

A. He does not.

Q. Why does he take this approach?

A. The PAIEUG model simply lacks the appropriate capability. Because Mr. Falkenberg's model cannot determine when transmission within PJM or between PJM and other areas is constrained, or its effects on dispatch and market prices, he simply ignores the issue.

Q. How does Mr. Falkenberg model imports and exports?

A. He assumes that they are the same in every hour of the year. He makes the same assumption about output from non-utility generators ("NUGs") and non-pumped storage hydro units.

Q. How does Mr. Falkenberg's treatment of imports affect his forecast of market prices?

A. Mr. Falkenberg's analysis includes an annual total volume of imports that is based on PJM forecasts. The main problem is that he assumes that imports are spread equally over all hours. This biases the price forecast, since the price impact of his having shifted imports away from high load periods to low load periods is to increase average market prices. This is because the PJM merit order (i.e., economic dispatch) is steeper when load is high than when it is not. Hence, a MW of net imports has a greater price impact in high load hours than in low load hours. As a result, once again the PAIEUG model forecasts in an artificially high market price.

Q. Does the same problem hold for NUGs?

A. Yes. Again, Mr. Falkenberg assumes that NUG generation is constant across all hours, regardless of variations in demand.

Q. Is there another problem with Mr. Falkenberg's modeling of imports?

A. Yes. The driving force behind the development of large, interconnected power systems in the United States has been to provide highly reliable supply to customers. PJM is connected to the East Central Area Reliability Coordination Agreement (ECAR) at 500 kV, to the Northeast Power Coordinating Council (NPCC) at 345 kV, and to the Virginia-Carolina System (VACAR) at 500 kV. These high voltage interconnections allow areas to support each other when power may be in short-supply in one region, and also supports economic transfers that reduce energy costs and energy prices.

Partially as a consequence of the high degree of integration of these other systems with PJM, customers rarely experience outages. PECO has informed me that in the last 10 years, there have been only five hours when PJM demand was not met. Three of those hours were during the winter of 1994 when an extended period of record cold led to very high levels of demand in the PJM. When I visited Mr. Falkenberg to review his results, I noted that his simulation for one year had about 100 hours of unserved energy in PJM. These are hours that his model projects that demand in PJM cannot be met. Thus, Mr. Falkenberg's model is completely unrealistic and historically inaccurate regarding this point.

This erroneous result may be due, in part, to Mr. Falkenberg's inability to model the imports that PJM companies routinely make from ECAR, VACAR, and NYPP. In other words, because the PAIEUG model cannot model transmission constraints, it creates an extremely skewed view of the energy world. The result in terms of price is that, at least during those 100 hours, the PJM price in his model is set by very expensive generators. These generators, in fact, virtually never run to meet PJM energy requirements. Therefore, Mr. Falkenberg's model again artificially inflates the market price.

Q. Dr. Hieronymus, please summarize your opinion regarding the PAIEUG model concerning dispatch, transmission constraints, and imports/exports.

A. PAIEUG either models these factors incorrectly or totally fails to include them. The simple reason for these failures is because PAIEUG's model is functionally unable to use these factors. Rather than attempt to account for these issues, PAIEUG simply assumes away their importance. Given the clear fact that these are significant, the failure of PAIEUG to model them reduces the credibility of its model and results based on it.

Q. Does the model used by OCA have similar limitations and biases?

A. Yes. The OCA assumes that NUG generation is flat across all hours in the year. In addition, although Mr. Smith indicated that his model has the ability to model multiple interconnected areas and unit commitment, Mr. Smith indicated during PHB's visit to his offices that he simplified his run and did not make use of these features. As a result, the OCA's model also fails to account for unit inflexibility. Further, Mr. Smith informed PHB that he relied on average as-operated heat rates from FERC Form 1 to project generator bidding behavior.[3] Average as-operated heat rates are even higher than full load heat rates. Therefore, Mr. Smith assumes that generators will bid at a level even higher than Mr. Falkenberg assumes. As a result, Mr. Smith's model, like Mr. Falkenberg's, systematically overstates market prices.

<u>E. Models Used by Utilities for Business Purposes</u>

Q. Is the GE MAPS model used by utilities and public policy-makers for purposes other than regulatory proceedings?

A. Yes. A number of utilities use GE MAPS for such purposes as price forecasting and transmission planning. Both the California Energy Commission and New York State Energy Office use GE MAPS for various policy analyses. I am also aware of confidential studies being performed for independent generating companies that are bidding to buy utility generating assets based on the use the GE MAPS model. Thus, the GE MAPS model is used in the "real world" of the electric utility industry.

3/ Mr. Smith indicated that the cite to EIA Form 860 data in his testimony was incorrect.

Q. Are the PROMOD and ICF models used by PECO's other market price witnesses also used for business purposes, as opposed to regulatory testimony purposes?

A. Yes.

Q. Is the Falkenberg model presented by PAIEUG used by anyone for any non-regulatory purposes?

A. No. My understanding is that Mr. Falkenberg built his model solely for the purpose of supporting his testimony in various proceedings. I certainly have not encountered it being used by anyone else, nor by Mr. Falkenberg in any context other than presenting testimony.

Q. In your opinion, is the Falkenberg model sufficiently comprehensive in nature that utilities or others would rely on it to make business decisions relating to generation investments?

A. No. It is far too rudimentary. For the reasons I have discussed, it is far less useful for determining the value of investments than the models used by commercial participants in the electricity industry.

Q. Is the ENPRO model presented by the OCA used by industry participants for business purposes?

A. Yes. I know of at least two utilities that use the ENPRO model. However, as I have discussed, Mr. Smith does not utilize many of ENPRO's features that make it a business-quality model.

Q. Mr. Falkenberg contends that he has benchmarked his model against nearly all of the industry-standard models, and that this demonstrates that his model is reliable. Do you agree?

A. No. First, I note that his benchmarking involved "increasing the level of detail [of his model] to that comparable with the most significant assumptions used by the utility model" (Falkenberg Testimony, p. 92). Mr. Falkenberg's "benchmarking" exercise does not demonstrate that his model, as presented in this proceeding, produces results similar to industry models. In fact, by admitting that he was forced to increase the capabilities of his model to perform this "benchmarking," Mr. Falkenberg implicitly admits that his model as actually run is inadequate. His exercise demonstrates that his simplified model cannot replicate, to any reasonable degree, the results of PHB, ICF, or EDS.

Second, while I have not reviewed his other purported benchmarking studies, the results in this case suggest that he has a generous standard for declaring that he has succeeded. Exhibit RJF-8 shows Mr. Falkenberg's benchmarking against the three models used by PECO's experts. Despite having supposedly used our individual assumptions, he misses my 1999 price by 12.4 percent, ICF's by 9.7 percent, and EDS's by 3.5 percent. While later years are closer, all three of the "benchmarks" show the same trend. He overestimates prices (based on supposedly comparable assumptions) in the early years and tends to underestimate them in later years. For all three benchmarks his results show that his model produces higher forecasts than PECO's three models. Because his forecasts are particularly higher in early years, the net present value difference is considerably greater than the simple average shown on his Exhibit RJF-8.

Q. Dr. Hieronymus, please summarize your conclusions regarding the models used by PAIEUG and the OCA.

A. The models used by PAIEUG and the OCA suffer from critical deficiencies. Their models either lack the capability to model important features (<u>e.g.</u>, transmission constraints), or the experts have chosen to ignore rather than model key issues. Moreover, the PAIEUG and OCA models, as presented Mr. Falkenberg and Mr. Smith in this proceeding, lack the reliability and sophistication to be used in making actual business decisions in the electric utility industry. Accordingly, the market price forecasts provided by these models are substantially invalid.

F. Fuel Prices

Q. What are the major issues regarding fuel price forecasts that are raised by the intervenors?

A. The main issues relate to: (1) base year fuel cost; and (2) fuel escalation rates.

1. Base Year Fuel Costs

Q. What are the base year fuel costs relied upon by the respective parties?

A. PHB has relied on spot delivered fuel prices as reported on EIA Form 423 and COALDAT® for residual oil and coal, respectively, and spot prices for gas, distillate, and jet fuel as reported in DRI's updated report. Both PAIEUG and the OCA used FERC Form 1 data on fuel costs.

Q. Is it appropriate to use Form 1 data for market price forecasting?

A. No. FERC Form 1 data are delivered fuel costs derived from accounting data. They are a mixture of spot and contract data. They can include other fixed costs that are in fuel accounts -- for example, costs of utility-owned rail cars and fixed pipeline reservation charges. The Form 1 data also may include adjustment from other years, further skewing the intervenors' results. Conversely, power plants are dispatched based on marginal fuel costs. For most plants, these are spot purchase costs, which PHB utilized.

Q. Please provide examples of how spot prices produce more realistic costing data.

A. A coal station with a one million ton long term coal contract, but the capacity to burn two million tons, will be dispatched based on the spot cost of coal, even if the contract price is much higher. Similarly, a gas-fired plant with fixed annual pipeline charges will be dispatched based on the commodity cost of gas. In both of these examples, the spot price is the actual cost, and will vary substantially from the reported FERC Form 1 data. From the perspective of the daily operation and dispatch of units, out-of-market coal contracts and fixed pipeline charges are "sunk costs" and, therefore, irrelevant.

An example of how FERC Form 1 data overstates the true fuel cost is shown below in Table 2, where I have listed the 1995 delivered prices for contract and spot coal from Form 423 and the 1995 FERC Form 1 average for Baltimore Gas and Electric's C.P. Crane units. In this example, the FERC Form 1 data substantially overestimates the spot price, while slightly underestimating the contract price.

Table 2
Example of Differences Between
FERC Form 423 Prices v. FERC Form 1 Fuel Prices
C.P. Crane Annual 1995 Coal Prices
($/MMBtu)

Source	Coal Price
Spot Coal (FERC Form 423)	1.56
Contract Coal	1.79
FERC Form 1	1.73

Because Baltimore Gas and Electric's cost of purchasing additional coal to produce additional energy is the spot price, $1.56/MMBtu is the appropriate basis for bidding the unit. In any hour in which Crane is on the margin, that bid will set the market energy price. Using Form 1 data would overstate the price by more than 10 percent. While I have shown only a single example, Form 1 data overstate prices for a great many PJM units.

Q. What is the result of PAIEUG and the OCA using Form 1 fuel cost data?

A. Because Form 1 data include fixed and contract costs, and contract costs generally are above spot costs (whether spot purchases or the incremental tonnage prices in contracts), they have overstated the starting year fuel costs for many generating units. They then escalate these too-high costs, resulting in overstated costs throughout their analyses. The overstated variable cost of generation in turn leads to overstated market prices.

Q. Are there other problems with the intervenors' fuel price methodology that leads to overstatement of fuel prices and hence of market prices?

A. Yes. Both Mr. Falkenberg and Mr. Smith use weighted averages of Form 1 oil and gas costs as the single fuel price for the year for dual fueled units. Mr. Falkenberg used the mix of fuels consumed in 1995 as reported in Form 1 for units that used both gas and residual oil in 1995. Mr. Smith assumes a mix of 50% residual oil and 50% gas, and relies on the 1996 Form 1 filings. It must be remembered that both of these approaches use Form 1 "prices" that already tend to be much higher than the true replacement costs of fuel that are used for pricing of units for dispatch purposes.

Winter oil and gas prices are almost always higher than summer and shoulder period prices. The use of annual averages means that winter oil and gas are being used on peak during the summer and setting market prices. This will artificially and significantly increase electricity prices in the PAIEUG and the OCA analyses during the summer months when demand in PJM is at its maximum and oil and gas prices are typically at their lowest.

Using Eddystone Units 3-4 as an example, Mr. Smith's weighting method would result in a summer fuel price of \$3.55/MMBtu (50% oil and 50% gas from 1996 Form 1), as compared with the summer (June - August) fuel prices of about \$2.83/MMBtu for actual deliveries of gas and oil to Eddystone in 1996 as reported in FERC Form 423. This would increase energy prices set by these units using Mr. Smith's methodology by about \$8/MWh in 1996 and \$12/MWh in 2009. As a result, Mr. Smith's market price forecast would be very substantially biased upwards, thereby reducing PECO's stranded costs.

Mr. Smith's method further compounds this error by escalating the high 1996 starting fuel price out over time using the escalation implied by the old DRI prices.

Q. Does Mr. Falkenberg make the same mistake regarding the use of annual average fuel costs?

Yes, he does. As noted above, he used 1995 Form 1 as his starting point and the mix of fuels as reported in 1995 Form 1 filings. Other than that, his methodology is the same as Mr. Smith's and suffers from the same flaws.

2. Fuel Price Escalators

Q. What are fuel price escalators?

A. Escalators are simply forecasts of the rate of inflation in the price of a fuel product. Forecasts of future prices are the product of multiplying a base price times the escalator. The higher the escalation factor, the higher the forecast of future prices will be.

Q. What escalators were used by PHB in running the GE MAPS model?

A. My direct testimony relied on fuel price forecasts from DRI/McGraw-Hill, which were published over a year ago and have since been updated.

Q. For purposes of these proceedings going forward, which escalator has PHB used?

A. I have updated my analysis to reflect DRI's latest escalators, the 1997 DRI forecast. The most significant difference is that DRI's updated forecast projects gas prices will rise at a slower rate than was projected in the prior forecast. This, in turn, lowers the forecasted market price for PECO.

Q. What fuel price escalators were used by PAIEUG and the OCA?

Mr. Falkenberg relies on the EIA fuel price forecasts produced by the U.S. Department of Energy; Mr. Smith relies on the old DRI forecast that was used in my direct testimony. However, the OCA subsequently has stated that it regards the EIA escalators as reasonable.[4]

Q. Is it reasonable for Mr. Falkenberg to rely on the EIA escalators?

A. We believe that the EIA forecast is a credible alternative to DRI. At PECO's request, I have run a sensitivity analysis in my rebuttal testimony that relies on the EIA escalators. This sensitivity analysis yields lower market prices, and therefore higher stranded costs for PECO,

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4/ PECO informs me that when OCA requested various sensitivity analyses, it wanted them run with the EIA fuel prices. OCA has represented to PECO that EIA provides a reasonable basis for escalators.

than my rebuttal case. Therefore, I believe that my reliance on the updated DRI forecast produces a conservative forecast.

Q. How is Mr. Smith's analysis affected by his reliance on the old DRI escalator forecast?

A. Given the trend in the market price of gas, DRI and other forecasters have reduced their projections for future gas prices. Lower future fuel prices implies lower future electricity prices, all else being equal. Therefore, Mr. Smith's reliance on the old DRI forecast will result in a higher market price of energy than if he were to update his analysis using the updated DRI forecast.

G. <u>Heat Rates</u>

Q. A major focus of criticisms by PAIEUG and the OCA concerning PECO's forecast was the use of incremental heat rates rather than full load average heat rates. Why did you use incremental heat rates for these proceedings?

A. We used incremental heat rates in part based on the "pool rules" which have been proposed to govern the relevant market. In short, we used these input assumptions because they reflect the rules of operation for generators in PJM.

Q. Please explain your decision to use incremental heat rates in greater detail.

A. In making market price forecasts, it is necessary and appropriate to utilize the best available information <u>applying the rules of the market in which market prices will be set</u>. The relevant information is provided in the instant case by the market rules for PJM -- in relevant part these are the rules that FERC ordered to be implemented in the spring of 1997. This proposal permits multi-part bids; consequently, marginal prices in the power exchange will be based on incremental energy bids. This filing does not anticipate any changes in these rules. Both the logic of the market rules and the initial requirement for cost-based bidding mandate that bids for incremental energy will be based on incremental heat rates and fuel costs.

Therefore, in using incremental heat rates, the assumptions used in GE MAPS to model how generators will bid into the pool are fully consistent with the basic economics of power system operations and the "pool rules" that will apply in the real world of electricity generation.

Q. Dr. Hieronymus, please summarize your position regarding the use of incremental heat rates and fuel costs to forecast market price.

A. Incremental heat rates and fuel costs are the appropriate basis for producing a valid forecast of market price <u>within</u> <u>PJM</u>. The pool rules result in bidding based on incremental heat rates, and such bidding behavior is economically efficient. Different pool rules, such as those that might develop in other regions, might legitimatize modeling other bidding behaviors, including a departure from incremental pricing. However, given the proposed PJM rules, price forecasts based on non-incremental fuel costs and heat rates will produce higher prices, and, in my opinion, will not produce valid market price forecasts for utilities within PJM, such as PECO.

Q. In addition to criticizing the overall use of incremental heat rates, PAIEUG also commented on the source of PHB's heat rates. What was this criticism?

A. PAIEUG claims that PHB "manufactured" estimates of incremental heat rates, and, in the process, relied on poorly documented and unreliable GE estimates.

Q. Is PAIEUG's criticism valid?

A. No. GE informs me that their data were derived from the 1979 EPRI Technical Assessment Guide ("EPRI TAG"). The heat rates for the existing combined cycle and combustion turbine units were based on the estimates of GE's turbine manufacturing division for state-of-the art units as of the early 1980's. The EPRI TAG is the industry standard "bible" used for generation planning. GE is a major manufacturer of turbines and it is reasonable to rely on GE as a source for combined cycle and combustion turbine heat rate data.

Q. If you regard these data as reliable, why and how did you modify them?

A. Both the EPRI TAG data and the turbine data we previously used were for state-of-the-art units with late 1970's and early 1980's design. Most of the coal units in PJM are older than this, with somewhat higher heat rates. Further, as noted in my direct testimony, the EPRI TAG estimates for certain types of coal units were optimistic relative to actual performance. To compensate for these factors, I increased the heat rates for existing fossil steam units, most by 5 percent and a few by 10 percent.

Q. In the analysis summarized in your Exhibit WHH-6, do you continue to rely on GE data as the source for heat rates?

A. Only in part. In order to remove an issue of dispute from this proceeding, I have adopted heat rates derived from EIA Form 860. This is the same data source used by PAIEUG. However, the EIA Form 860 data are for full load heat rates, not the incremental and no-load heat rates required for properly modeling unit commitment and PJM price formation. I am continuing to rely on the GE data for the relationship between full load and incremental heat rates. Also, EIA Form 860 data were not available for certain units; where Form 860 data were not available, I continue to rely on GE heat rate data.

Q. How important is the dispute about your use of GE data versus EIA Form 860 data?

A. The answer to that question must be given in two parts. First, it is important that I used, and continue to use, incremental rather than full load heat rates. For the reasons I have discussed and will discuss further, this is the only proper way to model price formation in PJM. The second issue is whether differences in the GE and EIA Form 860 full load heat rates are important. This question can be answered by comparing prices based on the two sources of input data.

Table 3 compares the weighted average full load heat rates as used in my original testimony for PJM, by unit type, to the weighted average full load heat rates reported in EIA Form 860 for the same units. This comparison shows that the EIA Form 860 full load heat rates are very similar to full load heat rates that were the basis for the incremental heat rates used in my original analysis.

Table 3
Comparison of Full Load Heat Rates
GE/PHB v. EIA Form 860
(BTUs/kWh)

	GE/PHB	Form 860
Coal	9,548	9,668
Gas/Oil	10,110	10,379
CTs	13,873	14,070

Table 4 compares PECO's average energy, capacity plus uplift revenues estimated by the model used in my direct testimony, PECO Statement No. 6, to an analysis in which EIA Form 860 full load heat rates are substituted for GE full load heat rates. As Table 4 below illustrates, the difference is small.

Table 4
Comparison of PECO's Average Energy, Capacity Plus Uplift
Assuming Different Underlying Full Load Heat Rates
GE/PHB v. EIA Form 860
($/MWh)

	GE/PHB	Form 860
1999	24.5	24.5
2004	37.6	37.6
2009	47.0	47.2

Table 4 graphically demonstrates that Mr. Falkenberg's criticism of the GE heat rates is unfounded. The GE heat rates closely parallel the Form 860 heat rates used by Mr. Falkenberg himself. Thus, Mr. Falkenberg's argument here is of no consequence for purposes of forecasting market price.

H. Bidding Incremental Costs

Q. How will owners of generation bid under the proposed market structure?

A. PJM market rules allow market sellers (i.e., generators selling into the pool) to submit separate bids for start-up, no-load, and incremental generation. If a generator submits separate bids for no-load, start-up, and energy, the pool rules assure that the generators receive the system marginal price and, in addition, a further payment designed to assure that it will at worst break even, as I describe in greater detail below. The ability to bid separately for no-load, start-up, and energy will provide generators with the opportunity to bid their incremental cost at all times without risking unprofitable operation.

By breaking their bids into three components and submitting bids based on their incremental costs, generators can assure that their units are committed when it is economic, and that, once committed, they will run during all hours when market prices will allow some contribution above incremental cost. This is the bidding strategy that a rational market player wishing to maximize profit would adopt.[5]

Generators who bid their actual start-up, no-load, and incremental energy costs at worst break even in any commitment cycle. If a unit that has been committed by PJM does not earn sufficient energy revenues to recover its bid for start-up, no-load, and energy produced, that generator will receive an operating reserve payment to compensate for making the unit available to PJM. This payment is what I referred to in my direct testimony as the negative net cycle cost collected through uplift.

5/ A generator owner who bids at higher than incremental cost may well lose available profits since bidding above incremental cost will sometimes lead to curtailed dispatch of the unit during those hours in which market prices are higher than the incremental cost of production, but lower than the owner's bid.

To summarize, the incremental heat rates and negative net cycle costs I have used in my price forecast are the best available assumptions. They realistically reflect the proposed pool rules and protect market efficiencies.

Q. Dr. Hieronymus, please comment specifically on the testimony of PAIEUG and the OCA regarding heat rates and negative net cycles.

A. Mr. Falkenberg from PAIEUG claims that we "hypothesized" the concept of negative net cycle days. (Falkenberg Testimony, p. 34). Respectfully, Mr. Falkenberg appears to lack full knowledge of the present PJM rules. For this testimony, we relied on those rules which are now in effect. PJM refers to this as "operating reserves." Payment for operating reserves is specified as follows:

> At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller: the total offered price for start-up and no-load fees and Spot Market Energy, determined on the basis of the resource's actual output or available and requested time and type of operation, shall be compared to the total value of the resource's Spot Market Energy. If the total offered price exceeds the total value, the difference shall be credited to the Market Seller (para. 3.2.3b, Schedule 7.01 of the PJM Operating Agreement).

Mr. Smith of the OCA also appears to be misinformed regarding the operative pool rules. He testified that PHB has assumed "an awkward uplift payment process that yields an economically inefficient price signal." (Smith Testimony, p. 7). The existence of the operating reserve payment covering negative net cycle costs is not an assumption, but an established fact of the rules. It also is not inefficient. Quite to the contrary, the purpose of the separate payment for unrecovered start-up and no-load costs is to avoid the inefficiency of bidding above incremental cost, as discussed above.

Q. Mr. Smith also quotes you as suggesting that a higher bid price is an alternative to the pool rule about negative net cycle recovery and criticizes you for not having analyzed this solution. Why didn't you address this alternative way of dealing with the problem?

A. To clarify, my direct testimony was that the negative cycle cost problem would have to be resolved either through pool rules or through owners bidding higher costs. PJM, like the New York Power Pool, allows such costs to be recovered separately from market energy prices. The alternative is for the owner to determine its pricing in a manner that avoids the problem. This solution is less efficient and is not the same as Mr. Smith's assumption that owners will bid full load average heat rate-based costs.

Q. How would an owner bid if there were no negative net cycle payments?

A. If an owner believes that the payments it will earn over a commitment cycle (e.g., a day) will cover its start-up and no-load costs, it will bid the unit at incremental cost. This maximizes profits. If, despite maximizing its profits by bidding at its incremental cost, the unit cannot avoid negative net cycle costs, the most attractive alternative for the unit's owner is to not be committed and not to run. Assuming that the owner can freely bid what it wishes, it will bid a very high price to assure that the unit will not run. For the reasons discussed below in responding to Mr. Falkenberg, bidding full load costs (as Mr. Smith and Mr. Falkenberg both assume owners will do) is not a profit-maximizing strategy.

Q. Mr. Falkenberg alleges that owners of generation will bid based on their average full load costs. Is this assumption correct?

A. No. There is no reason to do so. Market participants will receive the market clearing price, not merely their bid price.[6] For instance, if a generator bids $20/MWh and the market price is $28/MWh, it is paid $28/MWh.

6/ Of course, the bid price submitted by an individual unit generally is not equal to the market price. In any hour, only one or a few units will have prices at the market price. All other units either will be earning a contribution to profits or not running. Even the unit that sets the price in one hour generally will not set the price in the next hour.

Throughout his testimony Mr. Falkenberg mistakenly implies that market participants receive their individual bid price, not the market clearing price. This misconception leads Mr. Falkenberg to conclude that, under PHB's modeling, PJM generation owners can at best recover costs. This error is seen most clearly on page 42 of his testimony: "generators will . . . see that bidding incremental cost (and receiving an uplift payment) assures [that] at best they will break even, while bidding at average cost will at worst break even and probably make a profit." This statement clearly is untrue. Because they receive market clearing prices, not bid prices, generators do <u>not</u> risk "leaving something on the table" by bidding incremental cost. Further, bidding incremental cost increases the likelihood that the generator will be dispatched, thereby reducing the risk that the something is left on the table due to their having bid above incremental costs and not being dispatched.

Mr. Falkenberg is fully aware that units in PJM receive market clearing prices, not their bid price. His own analysis reflects this since PECO units are assumed to earn market prices, not bids. Why he assumed otherwise for purposes of criticizing PHB's analysis is not apparent. Clearly, had I made the assumption upon which his criticisms are based (<u>i.e.</u>, that each generator earns its bid price rather than the market price), PECO units would have earned zero energy market profits, since bids are based on costs and under that assumption there would be no profit.

Q. Does Mr. Falkenberg recognize the economic validity of the principle that competitive sellers will bid incremental costs?

Yes. Mr. Falkenberg recognizes that, in a competitive market, suppliers will set bids based on their incremental cost. However, he claims that suppliers will change their definition of incremental costs to equal average full load costs. (Falkenberg Testimony, p. 26). Full load average cost is above incremental costs in almost all cases. Even in a market structure that forbids bidding start-up, no-load, and incremental costs separately, this will not be the strategy adopted by generators.

Q. Why won't sellers bid full load cost in a market that ignores start-up and no-load costs?

A. For three reasons:

1. Contrary to Mr. Falkenberg's assertion, it does not guarantee that the generator will "at worst break even." If the generator bids full load costs but is dispatched at part load, it can lose money.

2. The strategy is not profit-maximizing. In fact, on a day when the unit owner confidently expects to cover its cycle costs, it will bid its incremental costs. On a day when it does not expect to cover its net cycle costs, it will bid high enough not to be dispatched.

3. Most importantly, bidding full load average costs will lead to an often infeasible and generally uneconomic (i.e., non-profit maximizing) dispatch of the unit. Most of the units in merit (i.e., dispatched) are somewhat to very substantially inflexible. A unit that must run at minimum load at night in order to be available the next day generally cannot expect to be dispatched if it is bid at full load cost. Yet, it cannot shut down at night and produce energy during the day.

Q. Does PAIEUG give any other reasons for rejecting incremental cost bidding?

A. Yes. Mr. Falkenberg also argues that current PJM rules are based on continued regulation, not market pricing. Without a shred of evidence, he seems to assume that if PJM petitioned FERC to lift the cost-based bidding requirement, and if FERC granted such authority, that PJM would jump to a single element bid system and that members would bid full-load average costs.

Q. Do any of the proposed regional power pools that do not require cost-based bidding retain the separate bidding of start-up, no-load and incremental prices?

A. Yes. The proposed rules of the New York Power Exchange structure bids in a manner essentially identical to the current PJM rules. The New York pricing system also allows recovery of negative net cycle costs.

Q. Independent of current PJM rules, is Mr. Falkenberg correct in assuming that PJM generation owners would bid full load average costs during overnight hours?

A. No. If the bids were stacked to determine who runs in the hour (the procedure in Mr. Falkenberg's model), an owner of a unit that must run at night to be available the next day would be required to bid low enough to remain on at minimum load. Hence, the overnight dispatch in such a system would include units bidding well below their full-load average costs and, in many cases, below even their incremental costs.

Q. If the assumed bidding behavior is not profit maximizing and the dispatch is technically infeasible, how does Mr. Falkenberg produce forecasts of market prices?

A. He simply ignores the infeasibility of the dispatch. His "solution" to the problem that his assumed bidding behavior is not profit maximizing for competitive producers is to assume the same non-competitive behavior for all producers. By assuming that all generators bid illogically and uneconomically, he creates prices high enough that much of this illogical behavior becomes justified. Thus, if I am the owner of a unit that must run overnight and know that other owners of similar units will bid their full load costs, I can bid higher than I otherwise could and remain dispatched. This tacitly collusive arrangement boosts market prices and, hence, the value of PECO's generation that he computes. However, it still will be true that the dispatch he relies on will be technically infeasible.

Q. Dr. Hieronymus, please summarize you opinion regarding the bidding of incremental costs.

A. Bidding incremental costs and heat rates is required by the current PJM pool rules, and such bidding behavior is economically efficient.

I. Variable O&M Costs

Q. Do PAIEUG and the OCA comment on the variable O&M costs used in the GE MAPS model?

A. Yes. PAIEUG alleges that PHB overstated variable O&M costs for PECO coal and CT units, relative to other units in PJM. Similarly, the OCA criticizes the differences between PECO's and other utilities' O&M costs.

Q. How did PHB establish the variable O&M for PECO and other companies?

A. Variable O&M data are not published. Therefore, we based our forecasts on actual data for PECO steam units and on GE data for non-PECO steam units. In most cases, differences between PECO estimates and the estimates used for non-PECO companies were not significant. Mr. Smith identified a few units where PECO's variable O&M was well above the more general estimates. PECO informed us that these particular units employ magnesium-oxide scrubbers, a technology that has high variable O&M (and is not used by any other PJM unit). Hence, the variable O&M for these units actually is higher than for other units, and we properly reflect this in our model. In addition, we applied PECO's assumption for variable O&M to all existing PJM combustion turbines.

J. Monte Carlo Simulations

Q. For what purpose are Monte Carlo simulations run to determine market price?

A. Monte Carlo simulation is one method of taking variable conditions into account. Most commonly, the variable investigated is the forced outage timing of generators.

Q. Mr. Falkenberg attempts to criticize the PHB analysis on the ground that it uses a single Monte Carlo simulation rather than multiple simulations. Is this criticism valid?

A. No. Mr. Falkenberg's criticism and supposed demonstration of its significance are absolutely invalid. He alleges that his Monte Carlo simulations (shown in Exhibit RJF-6) demonstrate that the average market price derived by GE MAPS could vary between iterations by as much as $3/MWh or 15 percent. (Falkenberg Testimony, p. 87). However, Mr. Falkenberg's analysis is based on a complete mischaracterization of what PHB did. Specifically, for each of his simulations, Mr. Falkenberg assumes that each PJM unit either has no forced outages or is out-of-service <u>for an entire year</u>. It is this unrealistic assumption, wholly of his own construction, that leads to extreme differences between his Monte Carlo iterations.

Q. Please explain exactly how PHB ran its Monte Carlo simulation.

A. What PHB actually did was to constrain the number of days of forced outages at each unit to its expected value. Thus, if the expected value of forced outage for a unit is five weeks per year, it is forced out in the GE MAPS run for exactly five weeks. GE MAPS then randomly selects a set of weeks for each generating unit to represent that unit's forced outages over the year. Unlike the situation in Mr. Falkenberg's Exhibit RJF-6, wherein a unit is out either zero or 365 weeks, the <u>number of weeks per year is not selected by random draw, only the timing of the outages</u>.

For example, assume that Cromby-1 is expected to be forced out for a total of four weeks during the year. MAPS will select four different weeks per year at random. These will be weeks in which Cromby-1 is unavailable. Next, assume that Limerick-1 is expected to experience five weeks of forced outages during the year. MAPS will select at random (and independently of Cromby-1) five weeks during the year for Limerick-1's forced outages. This is done independently for each unit in PJM (as well as NEPOOL and NYPP), for a total of over 1,000 units.

Q. Please explain the significance of how PHB actually ran the Monte Carlo simulation.

A. Because only a single run of MAPS is used for a given year, the GE MAPS analysis is based on a single time pattern of outages. The total amount of outage for each unit is at its expected value. Hence, each PECO unit will be available to earn revenues the proper number of hours per year. The particular time pattern selected may cause prices to be high in one week, relative to expected value (because of a concentration of forced outages), but it also will cause them to be low in another (because the random draw resulted in few outages). Since we are interested in revenues over the year, these week-to-week variations, similar to those experienced in reality, are unimportant. Moreover, because of the large number of units involved, the statistical "law of large numbers" means that even the week-to-week variations in prices caused by the pattern of outages will be small.

Q. Did PHB do any further runs of the simulation to verify this point?

A. Yes. To demonstrate that using a single Monte Carlo simulation provides an accurate and robust estimate of market price, we re-ran the 1999 simulation 11 times with randomly generated forced outages and computed the average revenues earned by indicative PECO units. The results are shown in Exhibit WHH-7. The important thing to note is that even for each single PECO unit, the range and variance of prices is small. Even this small variance exaggerates the importance of Mr. Falkenberg's criticism. What is ultimately of interest is the market value of PECO's generation units in the aggregate. The variance in the average price earned by all of PECO's units is smaller still than the variance in prices for individual units.

Q. Please summarize your response to Mr. Falkenberg's comments on Monte Carlo simulations.

A. First, the difference between the models' results for a single run versus multiple runs is de minimis, and should be ignored. The net difference is virtually impossible to note. Second, the issue is a total red herring. Mr. Falkenberg clearly misunderstood how the GE MAPS model used the Monte Carlo simulation. As clarified above, even Mr. Falkenberg should concede that this is a non-issue.

K. Cost of New Capacity

Q. The OCA and PAIEUG criticize PHB's estimates of the cost of new combined cycle and combustion turbine units. What are their main criticisms?

A. The OCA suggests that we did not include two types of costs in our estimates: interest during construction and project development "soft" costs. The OCA then bases its estimate of new capacity costs on PHB's estimate with these two adjustments, resulting in estimates a few percentage points higher. For combustion turbines, the OCA used $290/kW compared to PHB's $276/kW. PAIEUG had a number of criticisms, most of which relate to PHB's estimated cost for combined cycle units. Since my analysis builds only CTs in PJM (and NYPP), these criticisms generally are irrelevant. With respect to combustion turbines, PAIEUG noted also that our estimate did not include construction interest or a sufficient allowance for non-hardware costs, and made reference (without support) to contingencies, and the depletion of over-supplies of such units, etc. PAIEUG then selected a cost estimate of $300/ kW.

Q. Do you accept that you left some costs out of your combustion turbine cost estimate?

A. Yes. We have recalculated the cost of the combustion turbines used in our analysis, adding costs for a pipeline extension and construction interest, in addition to such items as transformers and switchgear, a distillate tank, land, other infrastructure that were already included in my estimate. As the OCA notes, we now may be overstating costs, since these cost items assume a greenfield site, which may not be necessary. (Smith Testimony, p. 19).

As a result of these changes, our new cost for combustion turbines is $298/kW. This is the costing estimate that we have used in the GE MAPS model for my rebuttal testimony. This forecast is just below PAIEUG's estimate ($300/kW) and is higher than the OCA's estimate ($290/kW). Therefore, the issue of the cost of a combustion turbine unit is no longer a substantial difference between our analysis and those of PAIEUG and the OCA.

Q. Have you also adjusted PHB's forecast to address criticisms of the fixed charge rates used to determine the annualized cost for combustion turbines?

A. Yes. The OCA asserts that we did not include state income taxes in the financing component of the fixed charge rate, nor did we take into account property taxes and insurance or capital additions. These assertions are not entirely true -- our levelized 12 percent capital charge rate includes a charge for just such other costs, equal to one percentage point of book net asset value. However, we accept that some costs were left out, particularly state income taxes. Therefore, we have adjusted our forecasts to address these issues. Specifically the OCA suggested a capital charge rate of 12.75 percent, and we have adopted this rate for our rebuttal analysis.

Q. Do the OCA and PAIEUG raise any other related concerns?

A. Yes. The OCA argues that some allowance needs to be made for A&G expense. The OCA uses a 10 percent adder to fixed O&M in deriving their estimate. Mr. Falkenberg raises some of these same criticisms. We have adopted this A&G estimate of a 10 percent adder in calculating fixed O&M for our rebuttal analysis.

Q. In terms of the value of capacity, what is the consequence of the changes in combustion turbine capital costs, fixed charge rate, and A&G that you have made?

A. We have used the annualized cost of a combustion turbine to estimate the value of capacity. These changes increase that value from the $35/kW used in my direct testimony to $40.2/kW in 1996 dollars.

Q. Given the revisions that you describe above, your capital cost assessment for a new combustion turbine is very similar to Mr. Falkenberg's. Are the other elements of your cost of new combustion turbines similar to Mr. Falkenberg's?

A. No. We are assuming $2/kW-yr (1996 dollars) for fixed O&M and, as noted above, $0.2/kW-yr for A&G, based on Mr. Smith's assessment. Thus, we have annual recurring fixed costs (beyond capital) of $2.2/kW-yr, which is slightly higher than Mr. Smith's, ICF's and EDS's estimates of $1.9/kW-yr.

In contrast, Mr. Falkenberg assumes that fixed O&M is approximately $6-7/kW-yr in 1996, which he then escalates over time.[7] This estimate is materially higher than the costs assumed by all other parties to this proceeding. In fact, Mr. Falkenberg's assumed fixed O&M costs are three times higher than the fixed O&M costs of the OCA and the PECO models, a totally unrealistic figure.

Q. Why are Mr. Falkenberg's estimated fixed costs so much higher than all the other models?

A. Mr. Falkenberg derived this value by assuming a base cost of $2-3/kW-yr for fixed O&M for new combustion turbines, which he then increased to reflect several adjustments. First, Mr. Falkenberg converted PECO's estimate of variable O&M to additional fixed O&M of approximately $2/kW-yr. He did this by assuming a certain number of hours of operation (as I recall based on our conversation, he assumed 500-1000 hours). Next, Mr. Falkenberg added about $1/kW-yr for A&G and $1/kW-yr for capital additions. This

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7/ This description is based on my understanding from my meeting with Mr. Falkenberg on June 25, 1997.

results in a \$4-\$5/kW-yr increase in the market price of capacity in 1996. In effect, Mr. Falkenberg has converted all variable O&M into fixed O&M.

Q. Do you agree with the additions that Mr. Falkenberg has made to the fixed costs of a new combustion turbine?

A. No, I do not. First, there really is variable O&M associated with these units, and it is unrealistic to assume otherwise. The frequency of required maintenance (and hence its cost) is determined by how many times these units are started and how much time they run. If they are used infrequently, significant O&M costs are avoided. Thus, it is not appropriate to "convert" variable O&M to fixed O&M, which artificially inflates market prices for capacity.

Second, I understand that there are virtually no capital additions associated with combustion turbines. My understanding is consistent with TVA's assumptions on which I relied. TVA breaks out fixed O&M and capital additions separately for each unit type. TVA shows no capital additions for combustion turbines. Thus, Mr. Falkenberg's use of captial additions is unwarranted.

IV. OTHER REBUTTAL ISSUES

Q. Are you responding to and rebutting the testimony of any other intervenors, in addition to PAIEUG and the OCA?

A. Yes. I have focused so far on those witnesses who have critiqued my analyses and presented their own forecasts. The remainder of my testimony responds to aspects of the testimony of parties whose rebuttal is at best tangential to the question of the market value of PECO's generation.

A. "Adjustments" to Stranded Costs Recovery

Q. OSBA witness Kalcic has suggested a stranded cost recovery "adjustment." Please explain this testimony.

A. Mr. Kalcic proposed that the PUC should implement a stranded cost "adjustment," to "share the risks between customer and shareholder" associated with the uncertainty of future market price estimates. In essence, the OSBA is simply suggesting that the PUC reduce PECO's stranded cost recovery because the OSBA believes that market price forecasting is somewhat uncertain.

Q. What is the OSBA's alleged proof of this uncertainty?

A. The OSBA asserts that running multiple, unspecified "sensitivity analyses" with the GE MAPS model might demonstrate that certain key variables cause asymmetric results compared to a reasonable base case. The OSBA asserts that the asymmetric results demonstrate uncertainty in the models used and may show bias in the base forecast.

Q. Do you agree with the OSBA's position?

A. I agree with part of what the OSBA is suggesting. PECO's stranded cost recovery should be based on the expected value of the market value of its generation. If the expected value can validly be demonstrated to be above or below the best estimate of a modal or median case, this should be reflected in stranded cost recovery.

However, the OSBA also proposes such an adjustment if the record in this case "remains incomplete" due to limited investigation of this issue. This betrays a presumption that asymmetry, should it exist, causes the expected level of market value to be above the best point estimate. This presumption is unwarranted. Many sensitivities, for example those relating to fuel costs, are likely to be symmetric. More importantly, some sensitivities will unambiguously cause expected values to be <u>below</u> the best estimate, such as: premature retirement or expensive retrofit of nuclear units for unit-specific or more general reasons, changes in environmental policies requiring expensive additions or premature shutdown of coal units, and technological changes that reduce the value of all existing generation. There are specific examples of each of these events over the past two decades; indeed, a major reason for the stranded costs of Pennsylvania utilities is precisely these sorts of forces. Thus, the asymmetries proposed by the OSBA could just as easily be used to support <u>increasing</u> the stranded cost recovery of PECO.

Mr. Kalcic's introduction of the concept of "risk sharing" to motivate a reduction in allowed stranded costs lacks even this weak foundation. His proposal can be interpreted as a simple attempt to provide a foundation for reducing PECO's stranded cost recovery by distorting a simple issue. In most modeling, there will be some asymmetries if variables are changed. However, such asymmetries are not a per se reason to discount or reduce the results of the model.

B. <u>Auctions of Generating Units</u>

Q. Do any of the witnesses for the intervenors suggest alternative approaches to calculating the value of generation assets?

A. The great majority of the witnesses accept the methodology used by PECO's models to calculate such value. However, Mr. Schoengold of the Environmentalists proposes an "auction" approach.

Q. Please describe Mr. Schoengold's proposal.

A. Mr. Schoengold proposes that, in view of the difficulty of forecasting market prices, PECO should be required (or induced) to sell its generation units at auction. Because he is concerned that the auction price will be too low, he recommends deferring the auction, with an interim stranded cost recovery to be "trued-up" to the auction price when the auction takes place.

Q. Separately from the fact that such an auction is not authorized under the Competition Act, does the auction proposal solve any problems associated with the uncertainty of the proper market price forecast to use for stranded cost calculation?

A. No. Substituting a sale price for a Commission-determined market value merely substitutes one estimate of future market revenues for another. In evaluating how much to pay for an asset, a bidder must first determine the future cash flows that it will generate. This is essentially the same enterprise in which the parties to this proceeding are engaged. There is no reason to believe the acquirer in an auction will be any more prescient than the participants in this proceeding.

The Environmentalists' auction proposal is further undermined because it requires a substantial delay period. The Competition Act requires a determination of stranded costs, then permitting the generation aspects of the industry to be deregulated. By requiring a delayed auction, thereby necessarily delaying deregulation, the Environmentalists' proposal would violate the intent of the Competition Act.

C. <u>Testimony by Indianapolis Power & Light</u>

Q. Mr. Brehm and Dr. Lewellen submit testimony on behalf of IPL in this proceeding addressing various stranded generating cost issues. Have you reviewed that testimony?

A. Yes. IPL simply has re-submitted the testimony of Mr. Brehm and Dr. Lewellen from the Securitization Proceeding.

Q. Did you fully respond to and rebut the testimony of Mr. Brehm and Dr. Lewellen in the Securitization Proceeding?

A. Yes. Therefore, rather than burden the record with repetitive testimony, I simply will re-submit my rebuttal testimony to Mr. Brehm and Dr. Lewellen from the Securitization Proceeding, attached hereto as Exhibit WHH-8.[8]

Q. Dr. Hieronymus, does this complete your rebuttal testimony?

A. Yes.

8/ I am re-submitting the rebuttal testimony from the Securitization Proceeding attached as Exhibit WHH-8 for the sole and limited purpose of rebutting the re-submitted testimony of Mr. Brehm and Dr. Lewellen. To the extent that the testimony in WHH-8 addresses other witnesses, such testimony may no longer be relevant, as most of the witnesses (such as Mr. Falkenberg), have substantially altered their testimony from the Securitization Proceeding.

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Capacity (MWs)		352	512	144			279	302	760	355	1,155	1,115
Capacity												
Factor	1999	85%	38%	61%			54%	63%	23%	85%	75%	75%
%	2000											
	2001											
	2002											
	2003											
	2004	86%	38%	74%			69%	72%	26%	86%	75%	75%
	2005											
	2006											
	2007											
	2008											
	2009	85%	38%	81%			79%	78%	25%	85%	75%	75%
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Energy												
Output	1999	2,631,789	1,693,000	764,156			1,319,310	1,662,404	1,524,535	2,657,446	7,595,118	7,332,084
MWh	2000											
	2001											
	2002											
	2003											
	2004	2,640,237	1,692,999	927,816			1,674,771	1,908,093	1,725,450	2,661,394	7,620,205	7,356,302
	2005											
	2006											
	2007											
	2008											
	2009	2,632,305	1,693,000	1,016,596			1,938,206	2,058,879	1,653,823	2,657,446	7,595,118	7,332,084
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
880	464	464	471	471		829	8,553			**Capacity (MWs)**
										Capacity
3%	75%	75%	75%	75%		0%		53%	1999	**Factor**
									2000	**%**
									2001	
									2002	
									2003	
8%	75%	75%	75%	75%		0%		55%	2004	
									2005	
									2006	
									2007	
									2008	
16%	75%	75%	75%	75%		0%		56%	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								Capacity		**Energy**
227,136	3,051,138	3,051,138	3,097,529	3,097,529		12,253	39,716,565	53%	1999	**Output**
							39,996,288	53%	2000	**MWh**
							40,277,982	54%	2001	
							40,561,660	54%	2002	
							40,847,336	55%	2003	
581,356	3,061,216	3,061,216	3,107,760	3,107,760		8,450	41,135,023	55%	2004	
							41,333,593	55%	2005	
							41,533,121	55%	2006	
							41,733,612	56%	2007	
							41,935,071	56%	2008	
1,258,063	3,051,138	3,051,138	3,097,529	3,097,529		4,648	42,137,502	56%	2009	
							42,340,911	57%	2010	
							42,545,302	57%	2011	
							42,750,679	57%	2012	
							42,957,047	57%	2013	
							43,164,412	58%	2014	
							43,372,778	58%	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Average Market Price of Energy $/MWh												
	1999	20.4	21.2	21.3			21.7	21.2	21.5	20.3	20.1	20.4
	2000											
	2001											
	2002											
	2003											
	2004	26.0	27.2	26.6			27.0	26.4	27.4	26.2	25.9	26.0
	2005											
	2006											
	2007											
	2008											
	2009	32.2	33.6	32.5			32.6	32.1	33.9	32.3	32.0	32.2
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Energy Revenues millions$												
	1999	$54	$36	$16			$29	$35	$33	$54	$153	$149
	2000	$56	$38	$18			$31	$38	$35	$57	$161	$157
	2001	$59	$40	$19			$34	$41	$38	$60	$169	$165
	2002	$62	$42	$21			$38	$44	$41	$63	$178	$173
	2003	$65	$44	$23			$41	$47	$44	$66	$187	$182
	2004	$69	$46	$25			$45	$50	$47	$70	$197	$191
	2005	$72	$48	$26			$48	$53	$49	$73	$206	$200
	2006	$75	$50	$28			$52	$56	$51	$76	$214	$208
	2007	$78	$52	$29			$55	$59	$52	$79	$224	$217
	2008	$81	$54	$31			$59	$63	$54	$82	$233	$227
	2009	$85	$57	$33			$63	$66	$56	$86	$243	$236
	2010	$89	$60	$35			$66	$70	$59	$90	$255	$249
	2011	$94	$63	$37			$70	$73	$62	$95	$269	$261
	2012	$99	$66	$38			$73	$77	$65	$100	$282	$275
	2013	$104	$69	$40			$77	$81	$69	$105	$297	$289
	2014	$109	$73	$43			$81	$85	$72	$110	$312	$304
	2015	$115	$77	$45			$85	$89	$76	$116	$328	$319

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
								($/MWh)		Average
25.7	20.3	20.3	20.3	20.3		26.2		20.5	1999	Market
									2000	Price of
									2001	Energy
									2002	$/MWh
									2003	
30.9	25.9	25.9	25.9	25.8		33.2		26.2	2004	
									2005	
									2006	
									2007	
									2008	
37.2	32.3	32.1	32.3	32.1		41.3		32.5	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								($/MWh)		Energy
$6	$62	$62	$63	$63		$0	$814	20.5	1999	Revenues
$7	$65	$65	$66	$66		$0	$861	21.5	2000	millions$
$9	$68	$68	$69	$69		$0	$910	22.6	2001	
$11	$72	$72	$73	$73		$0	$962	23.7	2002	
$14	$75	$75	$77	$77		$0	$1,018	24.9	2003	
$18	$79	$79	$81	$80		$0	$1,078	26.2	2004	
$22	$83	$83	$84	$84		$0	$1,130	27.3	2005	
$26	$87	$86	$88	$87		$0	$1,184	28.5	2006	
$32	$90	$90	$92	$91		$0	$1,242	29.8	2007	
$39	$94	$94	$96	$95		$0	$1,303	31.1	2008	
$47	$99	$98	$100	$99		$0	$1,368	32.5	2009	
$49	$104	$103	$105	$104		$0	$1,438	34.0	2010	
$52	$109	$108	$110	$110		$0	$1,512	35.5	2011	
$54	$115	$114	$116	$115		$0	$1,590	37.2	2012	
$57	$121	$120	$122	$121		$0	$1,672	38.9	2013	
$60	$127	$126	$128	$128		$0	$1,758	40.7	2014	
$63	$133	$132	$135	$134		$0	$1,849	42.6	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Uplift												
Revenues	1999	$0	$0	$0			$0	$0	$10	$0	$0	$0
millions$	2000	$0	$0	$0			$0	$0	$11	$0	$0	$0
	2001	$0	$0	$0			$0	$0	$11	$0	$0	$0
	2002	$0	$0	$0			$0	$0	$11	$0	$0	$0
	2003	$0	$0	$0			$0	$0	$11	$0	$0	$0
	2004	$0	$0	$0			$0	$0	$12	$0	$0	$0
	2005	$0	$0	$0			$0	$0	$12	$0	$0	$0
	2006	$0	$0	$0			$0	$0	$13	$0	$0	$0
	2007	$0	$0	$0			$0	$0	$13	$0	$0	$0
	2008	$0	$0	$0			$0	$0	$14	$0	$0	$0
	2009	$0	$0	$0			$0	$0	$15	$0	$0	$0
	2010	$0	$0	$0			$0	$0	$15	$0	$0	$0
	2011	$0	$0	$0			$0	$0	$16	$0	$0	$0
	2012	$0	$0	$0			$0	$0	$16	$0	$0	$0
	2013	$0	$0	$0			$0	$0	$17	$0	$0	$0
	2014	$0	$0	$0			$0	$0	$17	$0	$0	$0
	2015	$0	$0	$0			$0	$0	$18	$0	$0	$0
Energy												
Plus	1999	$54	$36	$16			$29	$35	$43	$54	$153	$149
Uplift	2000	$56	$38	$18			$31	$38	$46	$57	$161	$157
Revenues	2001	$59	$40	$19			$34	$41	$49	$60	$169	$165
millions$	2002	$62	$42	$21			$38	$44	$52	$63	$178	$173
	2003	$65	$44	$23			$41	$47	$55	$66	$187	$182
	2004	$69	$46	$25			$45	$50	$59	$70	$197	$191
	2005	$72	$48	$26			$48	$53	$61	$73	$206	$200
	2006	$75	$50	$28			$52	$56	$63	$76	$214	$208
	2007	$78	$52	$29			$55	$59	$66	$79	$224	$217
	2008	$81	$54	$31			$59	$63	$68	$82	$233	$227
	2009	$85	$57	$33			$63	$66	$71	$86	$243	$236
	2010	$89	$60	$35			$66	$70	$74	$90	$255	$249
	2011	$94	$63	$37			$70	$73	$78	$95	$269	$261
	2012	$99	$66	$38			$73	$77	$81	$100	$282	$275
	2013	$104	$69	$40			$77	$81	$85	$105	$297	$289
	2014	$109	$73	$43			$81	$85	$89	$110	$312	$304
	2015	$115	$77	$45			$85	$89	$94	$116	$328	$319

Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	**Total**	**Average**	**Year**	
								($/MWh)		**Uplift**
$0	$0	$0	$0	$0		$3	$13	0.3	1999	**Revenues**
$0	$0	$0	$0	$0		$3	$13	0.3	2000	**millions$**
$0	$0	$0	$0	$0		$3	$14	0.3	2001	
$0	$0	$0	$0	$0		$3	$14	0.3	2002	
$0	$0	$0	$0	$0		$3	$14	0.3	2003	
$0	$0	$0	$0	$0		$2	$15	0.4	2004	
$1	$0	$0	$0	$0		$2	$15	0.4	2005	
$1	$0	$0	$0	$0		$2	$16	0.4	2006	
$1	$0	$0	$0	$0		$2	$16	0.4	2007	
$1	$0	$0	$0	$0		$2	$17	0.4	2008	
$2	$0	$0	$0	$0		$2	$18	0.4	2009	
$2	$0	$0	$0	$0		$2	$19	0.4	2010	
$2	$0	$0	$0	$0		$2	$19	0.5	2011	
$2	$0	$0	$0	$0		$2	$20	0.5	2012	
$2	$0	$0	$0	$0		$2	$21	0.5	2013	
$2	$0	$0	$0	$0		$2	$21	0.5	2014	
$2	$0	$0	$0	$0		$2	$22	0.5	2015	
								($/MWh)		**Energy**
$6	$62	$62	$63	$63		$3	$828	20.8	1999	**Plus**
$7	$65	$65	$66	$66		$3	$874	21.9	2000	**Uplift**
$9	$68	$68	$69	$69		$3	$923	22.9	2001	**Revenues**
$11	$72	$72	$73	$73		$3	$976	24.1	2002	**millions$**
$14	$75	$75	$77	$77		$3	$1,032	25.3	2003	
$18	$79	$79	$81	$80		$3	$1,093	26.6	2004	
$22	$83	$83	$84	$84		$3	$1,145	27.7	2005	
$27	$87	$86	$88	$87		$2	$1,200	28.9	2006	
$33	$90	$90	$92	$91		$2	$1,258	30.1	2007	
$40	$94	$94	$96	$95		$2	$1,320	31.5	2008	
$48	$99	$98	$100	$99		$2	$1,386	32.9	2009	
$51	$104	$103	$105	$104		$2	$1,457	34.4	2010	
$53	$109	$108	$110	$110		$2	$1,532	36.0	2011	
$56	$115	$114	$116	$115		$2	$1,610	37.7	2012	
$59	$121	$120	$122	$121		$2	$1,693	39.4	2013	
$62	$127	$126	$128	$128		$2	$1,780	41.2	2014	
$65	$133	$132	$135	$134		$2	$1,871	43.1	2015	

	Year	Conemaugh	Conowingo	Cromby1	Cromby 2	Delaware	Eddystone	Eddystone	Eddystone	Keystone1&2	Limerick 1	Limerick 2
		Cone 1&2	Cono	Cromby1	Cromby 2	Dela 7&8	Eddy 1	Eddy 2	Eddy 3&4	Key 1&2	Limerick 1	Limerick 2
Capacity												
Price	1999	16.0	16.0	16.0			16.0	16.0	16.0	16.0	16.0	16.0
$/KW	2000	27.0	27.0	27.0			27.0	27.0	27.0	27.0	27.0	27.0
	2001	45.4	45.4	45.4			45.4	45.4	45.4	45.4	45.4	45.4
	2002	46.7	46.7	46.7			46.7	46.7	46.7	46.7	46.7	46.7
	2003	48.1	48.1	48.1			48.1	48.1	48.1	48.1	48.1	48.1
	2004	49.6	49.6	49.6			49.6	49.6	49.6	49.6	49.6	49.6
	2005	51.3	51.3	51.3			51.3	51.3	51.3	51.3	51.3	51.3
	2006	53.1	53.1	53.1			53.1	53.1	53.1	53.1	53.1	53.1
	2007	55.0	55.0	55.0			55.0	55.0	55.0	55.0	55.0	55.0
	2008	56.9	56.9	56.9			56.9	56.9	56.9	56.9	56.9	56.9
	2009	59.0	59.0	59.0			59.0	59.0	59.0	59.0	59.0	59.0
	2010	61.0	61.0	61.0			61.0	61.0	61.0	61.0	61.0	61.0
	2011	63.2	63.2	63.2			63.2	63.2	63.2	63.2	63.2	63.2
	2012	65.5	65.5	65.5			65.5	65.5	65.5	65.5	65.5	65.5
	2013	67.8	67.8	67.8			67.8	67.8	67.8	67.8	67.8	67.8
	2014	70.2	70.2	70.2			70.2	70.2	70.2	70.2	70.2	70.2
	2015	72.8	72.8	72.8			72.8	72.8	72.8	72.8	72.8	72.8
Capacity												
Revenues	1999	$6	$8	$2			$4	$5	$12	$6	$19	$18
millions$	2000	$9	$14	$4			$8	$8	$20	$10	$31	$30
	2001	$16	$23	$7			$13	$14	$34	$16	$52	$51
	2002	$16	$24	$7			$13	$14	$35	$17	$54	$52
	2003	$17	$25	$7			$13	$15	$37	$17	$56	$54
	2004	$17	$25	$7			$14	$15	$38	$18	$57	$55
	2005	$18	$26	$7			$14	$15	$39	$18	$59	$57
	2006	$19	$27	$8			$15	$16	$40	$19	$61	$59
	2007	$19	$28	$8			$15	$17	$42	$20	$63	$61
	2008	$20	$29	$8			$16	$17	$43	$20	$66	$63
	2009	$21	$30	$8			$16	$18	$45	$21	$68	$66
	2010	$21	$31	$9			$17	$18	$46	$22	$71	$68
	2011	$22	$32	$9			$18	$19	$48	$22	$73	$71
	2012	$23	$34	$9			$18	$20	$50	$23	$76	$73
	2013	$24	$35	$10			$19	$20	$52	$24	$78	$76
	2014	$25	$36	$10			$20	$21	$53	$25	$81	$78
	2015	$26	$37	$10			$20	$22	$55	$26	$84	$81

Muddy Run	**PeachBotto**	**PeachBotto**	**Salem 1**	**Salem 2**	**Schuylkill**	**CT's**				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	**Total**	**Average**	**Year**	
								($/KW)		**Capacity**
16.0	16.0	16.0	16.0	16.0		16.0		16.0	1999	**Price**
27.0	27.0	27.0	27.0	27.0		27.0		27.0	2000	**$/KW**
45.4	45.4	45.4	45.4	45.4		45.4		45.4	2001	
46.7	46.7	46.7	46.7	46.7		46.7		46.7	2002	
48.1	48.1	48.1	48.1	48.1		48.1		48.1	2003	
49.6	49.6	49.6	49.6	49.6		49.6		49.6	2004	
51.3	51.3	51.3	51.3	51.3		51.3		51.3	2005	
53.1	53.1	53.1	53.1	53.1		53.1		53.1	2006	
55.0	55.0	55.0	55.0	55.0		55.0		55.0	2007	
56.9	56.9	56.9	56.9	56.9		56.9		56.9	2008	
59.0	59.0	59.0	59.0	59.0		59.0		59.0	2009	
61.0	61.0	61.0	61.0	61.0		61.0		61.0	2010	
63.2	63.2	63.2	63.2	63.2		63.2		63.2	2011	
65.5	65.5	65.5	65.5	65.5		65.5		65.5	2012	
67.8	67.8	67.8	67.8	67.8		67.8		67.8	2013	
70.2	70.2	70.2	70.2	70.2		70.2		70.2	2014	
72.8	72.8	72.8	72.8	72.8		72.8		72.8	2015	
								($/MWh)		**Capacity**
$14	$7	$7	$8	$8		$13	$137	3.5	1999	**Revenues**
$24	$13	$13	$13	$13		$22	$231	5.8	2000	**millions$**
$40	$21	$21	$21	$21		$38	$388	9.6	2001	
$41	$22	$22	$22	$22		$39	$399	9.8	2002	
$42	$22	$22	$23	$23		$40	$411	10.1	2003	
$44	$23	$23	$23	$23		$41	$425	10.3	2004	
$45	$24	$24	$24	$24		$43	$439	10.6	2005	
$47	$25	$25	$25	$25		$44	$454	10.9	2006	
$48	$26	$26	$26	$26		$46	$470	11.3	2007	
$50	$26	$26	$27	$27		$47	$487	11.6	2008	
$52	$27	$27	$28	$28		$49	$504	12.0	2009	
$54	$28	$28	$29	$29		$51	$522	12.3	2010	
$56	$29	$29	$30	$30		$52	$541	12.7	2011	
$58	$30	$30	$31	$31		$54	$560	13.1	2012	
$60	$31	$31	$32	$32		$56	$580	13.5	2013	
$62	$33	$33	$33	$33		$58	$601	13.9	2014	
$64	$34	$34	$34	$34		$60	$622	14.4	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Energy												
Plus	1999	$59	$44	$19			$33	$40	$55	$60	$171	$167
Uplift	2000	$66	$52	$22			$39	$46	$66	$66	$192	$187
Plus	2001	$75	$63	$26			$47	$54	$83	$76	$222	$215
Capacity	2002	$79	$66	$28			$51	$58	$87	$79	$232	$225
Revenues	2003	$82	$68	$30			$55	$61	$92	$83	$243	$236
millions$	2004	$86	$71	$32			$59	$65	$97	$87	$255	$247
	2005	$90	$74	$34			$63	$69	$100	$91	$265	$257
	2006	$93	$77	$35			$66	$72	$104	$95	$276	$267
	2007	$97	$80	$37			$71	$76	$108	$99	$287	$278
	2008	$101	$84	$39			$75	$80	$111	$103	$299	$290
	2009	$106	$87	$42			$80	$84	$115	$107	$311	$302
	2010	$111	$91	$44			$83	$88	$120	$112	$326	$317
	2011	$116	$95	$46			$87	$92	$126	$117	$342	$332
	2012	$122	$100	$48			$92	$97	$131	$123	$358	$348
	2013	$128	$104	$50			$96	$101	$137	$129	$375	$365
	2014	$134	$109	$53			$101	$106	$143	$135	$393	$382
	2015	$140	$114	$55			$106	$111	$149	$142	$412	$401

Muddy Run Muddy R	**PeachBotto** Peach B 2	**PeachBotto** Peach B 3	**Salem 1** Salem 1	**Salem 2** Salem 2	**Schuylkill** Schuylk 1	**CT's** CT's	**Total**	**Average**	**Year**	
								($/MWh)		**Energy**
$20	$69	$69	$70	$71		$16	$965	24.3	1999	**Plus**
$31	$78	$78	$79	$79		$25	$1,105	27.6	2000	**Uplift**
$49	$89	$89	$91	$91		$41	$1,312	32.6	2001	**Plus**
$53	$94	$94	$95	$95		$42	$1,376	33.9	2002	**Capacity**
$57	$98	$98	$99	$99		$43	$1,444	35.3	2003	**Revenues**
$62	$102	$102	$104	$104		$44	$1,517	36.9	2004	**millions$**
$67	$107	$106	$108	$108		$45	$1,584	38.3	2005	
$74	$111	$111	$113	$112		$46	$1,654	39.8	2006	
$81	$116	$116	$118	$117		$48	$1,728	41.4	2007	
$90	$121	$120	$123	$122		$49	$1,807	43.1	2008	
$100	$126	$125	$128	$127		$51	$1,890	44.9	2009	
$105	$132	$131	$134	$133		$53	$1,979	46.7	2010	
$109	$138	$138	$140	$140		$54	$2,073	48.7	2011	
$114	$145	$144	$147	$146		$56	$2,170	50.8	2012	
$119	$152	$151	$154	$153		$58	$2,273	52.9	2013	
$124	$159	$158	$161	$161		$61	$2,380	55.1	2014	
$129	$167	$166	$169	$168		$63	$2,493	57.5	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Average												
Fuel	1999	12.1	0.0	16.2			16.3	15.8	27.7	11.9	4.5	4.5
Cost	2000											
$/MWh	2001											
	2002											
	2003											
	2004	14.0	0.0	18.8			18.8	18.6	33.6	17.5	4.6	4.6
	2005											
	2006											
	2007											
	2008											
	2009	15.4	0.0	20.6			20.6	20.6	42.0	21.0	5.4	5.4
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Fuel												
Cost	1999	$32	$0	$12			$21	$26	$42	$32	$34	$33
million$	2000	$33	$0	$13			$23	$28	$45	$34	$34	$32
	2001	$34	$0	$14			$25	$30	$48	$37	$34	$32
	2002	$35	$0	$15			$27	$32	$51	$40	$34	$33
	2003	$36	$0	$16			$29	$33	$54	$43	$35	$33
	2004	$37	$0	$17			$32	$36	$58	$47	$35	$34
	2005	$38	$0	$18			$33	$37	$60	$48	$36	$34
	2006	$38	$0	$19			$35	$38	$62	$50	$37	$36
	2007	$39	$0	$19			$36	$40	$65	$52	$39	$37
	2008	$40	$0	$20			$38	$41	$67	$54	$40	$39
	2009	$40	$0	$21			$40	$42	$70	$56	$41	$40
	2010	$41	$0	$21			$41	$43	$73	$57	$43	$41
	2011	$42	$0	$22			$42	$44	$77	$58	$44	$43
	2012	$43	$0	$22			$43	$45	$81	$60	$46	$44
	2013	$44	$0	$23			$44	$46	$85	$61	$48	$46
	2014	$45	$0	$23			$45	$48	$89	$63	$49	$48
	2015	$46	$0	$24			$46	$49	$94	$64	$51	$49

Muddy Run	**PeachBotto**	**PeachBotto**	**Salem 1**	**Salem 2**	**Schuylkill**	**CT's**				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	**Total**	**Average**	**Year**	
								($/MWh)		**Average**
25.0	5.8	5.8	5.8	5.8		257.1		7.9	1999	**Fuel**
									2000	**Cost**
									2001	**$/MWh**
									2002	
									2003	
31.7	5.8	5.8	5.8	5.8		320.7		9.4	2004	
									2005	
									2006	
									2007	
									2008	
38.5	6.8	6.8	6.8	6.8		405.3		11.5	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	
								($/MWh)		**Fuel**
$6	$18	$18	$18	$18		$3	$313	7.9	1999	**Cost**
$7	$18	$18	$18	$18		$3	$323	8.1	2000	**million$**
$9	$17	$17	$18	$18		$3	$336	8.3	2001	
$12	$17	$17	$18	$18		$3	$352	8.7	2002	
$15	$18	$18	$18	$18		$3	$369	9.0	2003	
$18	$18	$18	$18	$18		$3	$388	9.4	2004	
$22	$18	$18	$18	$18		$3	$403	9.7	2005	
$27	$19	$19	$19	$19		$2	$421	10.1	2006	
$33	$20	$20	$20	$20		$2	$441	10.6	2007	
$40	$20	$20	$21	$21		$2	$462	11.0	2008	
$48	$21	$21	$21	$21		$2	$485	11.5	2009	
$51	$22	$22	$22	$22		$2	$502	11.9	2010	
$54	$22	$22	$23	$23		$2	$519	12.2	2011	
$56	$23	$23	$24	$24		$2	$537	12.6	2012	
$59	$24	$24	$24	$24		$2	$556	12.9	2013	
$62	$25	$25	$25	$25		$2	$575	13.3	2014	
$65	$26	$26	$26	$26		$3	$595	13.7	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Revenues												
Minus	1999	$27	$44	$6			$12	$14	$13	$28	$137	$134
Fuel	2000	$33	$52	$8			$16	$18	$21	$32	$158	$155
Costs	2001	$41	$63	$12			$22	$25	$35	$39	$188	$183
million$	2002	$44	$66	$12			$24	$26	$36	$40	$198	$192
	2003	$46	$68	$13			$25	$28	$37	$40	$208	$202
	2004	$49	$71	$14			$27	$30	$39	$41	$220	$213
	2005	$52	$74	$15			$30	$32	$40	$43	$229	$222
	2006	$55	$77	$17			$32	$34	$41	$44	$239	$232
	2007	$58	$80	$18			$34	$36	$43	$47	$248	$241
	2008	$62	$84	$19			$37	$39	$44	$49	$259	$251
	2009	$65	$87	$21			$40	$42	$46	$51	$270	$262
	2010	$69	$91	$22			$43	$45	$47	$55	$283	$275
	2011	$74	$95	$24			$46	$48	$49	$59	$297	$289
	2012	$78	$100	$25			$49	$51	$50	$63	$312	$303
	2013	$83	$104	$27			$52	$55	$52	$68	$328	$319
	2014	$88	$109	$29			$56	$59	$53	$73	$344	$334
	2015	$94	$114	$31			$60	$63	$55	$78	$361	$351

Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average	Year	
								($/MWh)		Revenues
$14	$52	$52	$52	$52		$13	$651	16.4	1999	Minus
$24	$60	$60	$61	$61		$22	$781	19.5	2000	Fuel
$40	$72	$72	$73	$73		$38	$976	24.2	2001	Costs
$41	$76	$76	$77	$77		$39	$1,024	25.2	2002	million$
$42	$80	$80	$82	$81		$40	$1,075	26.3	2003	
$44	$84	$84	$86	$86		$41	$1,129	27.5	2004	
$45	$88	$88	$90	$89		$43	$1,181	28.6	2005	
$47	$92	$92	$94	$93		$44	$1,233	29.7	2006	
$48	$96	$96	$98	$97		$46	$1,288	30.9	2007	
$50	$101	$100	$102	$101		$47	$1,345	32.1	2008	
$52	$105	$104	$106	$106		$49	$1,406	33.4	2009	
$54	$110	$110	$112	$111		$51	$1,477	34.9	2010	
$56	$116	$115	$117	$117		$52	$1,554	36.5	2011	
$58	$122	$121	$123	$123		$54	$1,633	38.2	2012	
$60	$128	$127	$130	$129		$56	$1,717	40.0	2013	
$62	$134	$134	$136	$135		$58	$1,805	41.8	2014	
$64	$141	$140	$143	$142		$60	$1,898	43.8	2015	

	Year	Conemaugh Cone 1&2	Conowingo Cono	Cromby1 Cromby1	Cromby 2 Cromby 2	Delaware Dela 7&8	Eddystone Eddy 1	Eddystone Eddy 2	Eddystone Eddy 3&4	Keystone1&2 Key 1&2	Limerick 1 Limerick 1	Limerick 2 Limerick 2
Variable												
O&M Cost	1999	2.2	0.0	3.6			4.3	3.4	0.5	2.2	0.6	0.6
$/MWh	2000											
	2001											
	2002											
	2003											
	2004	2.5	0.0	4.1			4.9	3.9	0.6	2.5	0.7	0.7
	2005											
	2006											
	2007											
	2008											
	2009	2.9	0.0	4.8			5.8	4.6	0.7	2.9	0.9	0.9
	2010											
	2011											
	2012											
	2013											
	2014											
	2015											
Variable												
O&M Cost	1999	$6	$0	$3			$6	$6	$1	$6	$5	$5
million$	2000	$6	$0	$3			$6	$6	$1	$6	$5	$5
	2001	$6	$0	$3			$7	$6	$1	$6	$5	$5
	2002	$6	$0	$3			$7	$7	$1	$6	$5	$5
	2003	$6	$0	$4			$8	$7	$1	$6	$5	$5
	2004	$7	$0	$4			$8	$7	$1	$6	$6	$5
	2005	$7	$0	$4			$9	$8	$1	$7	$6	$5
	2006	$7	$0	$4			$9	$8	$1	$7	$6	$6
	2007	$7	$0	$4			$10	$9	$1	$7	$6	$6
	2008	$7	$0	$5			$11	$9	$1	$7	$6	$6
	2009	$8	$0	$5			$11	$10	$1	$8	$6	$6
	2010	$8	$0	$5			$12	$10	$1	$8	$7	$6
	2011	$8	$0	$5			$12	$10	$1	$8	$7	$7
	2012	$9	$0	$5			$13	$11	$1	$9	$7	$7
	2013	$9	$0	$6			$13	$11	$1	$9	$8	$7
	2014	$9	$0	$6			$13	$11	$1	$9	$8	$7
	2015	$10	$0	$6			$14	$12	$1	$10	$8	$8

Muddy Run Muddy R	PeachBotto Peach B 2	PeachBotto Peach B 3	Salem 1 Salem 1	Salem 2 Salem 2	Schuylkill Schuylk 1	CT's CT's	Total	Average	Year	
								($/MWh)		Variable
0.0	0.6	0.6	0.6	0.6		2.3		1.1	1999	O&M Cost
									2000	$/MWh
									2001	
									2002	
									2003	
0.0	0.7	0.7	0.7	0.7		2.7		1.3	2004	
									2005	
									2006	
									2007	
									2008	
0.0	0.9	0.9	0.9	0.9		3.2		1.6	2009	
									2010	
									2011	
									2012	
									2013	
									2014	
									2015	

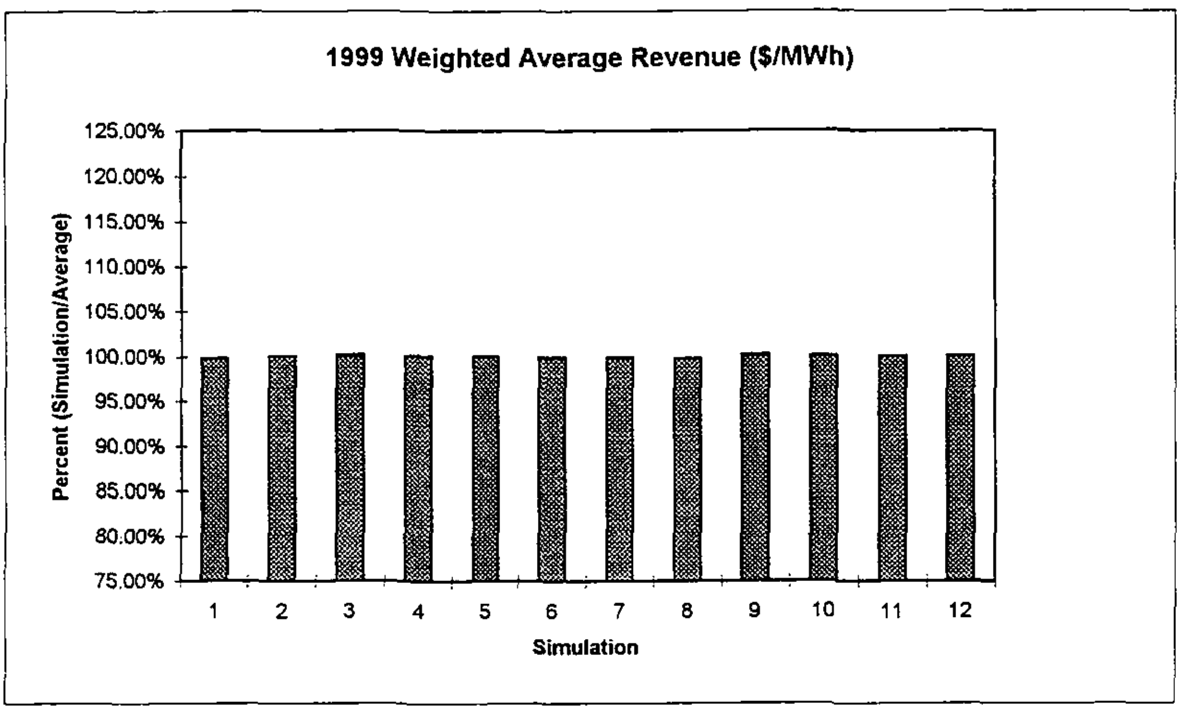
								($/MWh)		Variable
$0	$2	$2	$2	$2		$0	$44	1.1	1999	O&M Cost
$0	$2	$2	$2	$2		$0	$46	1.1	2000	*million$*
$0	$2	$2	$2	$2		$0	$48	1.2	2001	
$0	$2	$2	$2	$2		$0	$50	1.2	2002	
$0	$2	$2	$2	$2		$0	$52	1.3	2003	
$0	$2	$2	$2	$2		$0	$54	1.3	2004	
$0	$2	$2	$2	$2		$0	$56	1.4	2005	
$0	$2	$2	$2	$2		$0	$59	1.4	2006	
$0	$3	$3	$3	$3		$0	$61	1.5	2007	
$0	$3	$3	$3	$3		$0	$64	1.5	2008	
$0	$3	$3	$3	$3		$0	$66	1.6	2009	
$0	$3	$3	$3	$3		$0	$69	1.6	2010	
$0	$3	$3	$3	$3		$0	$71	1.7	2011	
$0	$3	$3	$3	$3		$0	$74	1.7	2012	
$0	$3	$3	$3	$3		$0	$76	1.8	2013	
$0	$3	$3	$3	$3		$0	$79	1.8	2014	
$0	$3	$3	$3	$3		$0	$82	1.9	2015	

	Year	*Conemaugh* Cone 1&2	*Conowingo* Cono	*Cromby1* Cromby1	*Cromby 2* Cromby 2	*Delaware* Dela 7&8	*Eddystone* Eddy 1	*Eddystone* Eddy 2	*Eddystone* Eddy 3&4	*Keystone1&2* Key 1&2	*Limerick 1* Limerick 1	*Limerick 2* Limerick 2
Total												
Incremental	1999	$38	$0	$15			$27	$32	$43	$37	$39	$37
Costs	2000	$39	$0	$16			$29	$34	$46	$40	$39	$37
million$	2001	$40	$0	$17			$32	$36	$49	$43	$39	$37
	2002	$41	$0	$19			$34	$38	$52	$46	$40	$38
	2003	$42	$0	$20			$37	$41	$55	$50	$40	$39
	2004	$44	$0	$21			$40	$43	$59	$53	$41	$39
	2005	$44	$0	$22			$42	$45	$61	$55	$42	$40
	2006	$45	$0	$23			$44	$46	$63	$57	$43	$42
	2007	$46	$0	$24			$46	$48	$66	$59	$45	$43
	2008	$47	$0	$25			$49	$50	$68	$61	$47	$45
	2009	$48	$0	$26			$51	$52	$71	$64	$48	$46
	2010	$49	$0	$27			$52	$53	$74	$65	$50	$48
	2011	$51	$0	$27			$54	$55	$78	$67	$52	$50
	2012	$52	$0	$28			$55	$56	$82	$68	$53	$52
	2013	$53	$0	$29			$57	$57	$86	$70	$55	$53
	2014	$55	$0	$29			$58	$59	$91	$72	$57	$55
	2015	$56	$0	$30			$60	$60	$95	$74	$59	$57
Margin												
million$	1999	$22	$44	$4			$6	$8	$12	$22	$132	$130
	2000	$27	$52	$5			$10	$12	$20	$26	$153	$150
	2001	$35	$63	$8			$15	$18	$34	$33	$183	$178
	2002	$38	$66	$9			$17	$20	$35	$33	$192	$187
	2003	$40	$68	$10			$18	$21	$37	$34	$203	$197
	2004	$43	$71	$11			$19	$22	$38	$34	$214	$207
	2005	$45	$74	$11			$21	$24	$39	$36	$223	$217
	2006	$48	$77	$12			$22	$26	$40	$37	$233	$226
	2007	$51	$80	$13			$24	$28	$42	$39	$242	$235
	2008	$54	$84	$15			$26	$30	$43	$41	$252	$245
	2009	$57	$87	$16			$28	$32	$45	$43	$263	$256
	2010	$61	$91	$17			$31	$35	$46	$47	$276	$268
	2011	$65	$95	$18			$34	$38	$48	$51	$290	$282
	2012	$70	$100	$20			$36	$41	$49	$55	$305	$296
	2013	$74	$104	$22			$39	$44	$51	$59	$320	$311
	2014	$79	$109	$23			$43	$47	$52	$63	$336	$327
	2015	$84	$114	$25			$46	$51	$54	$68	$353	$343

Muddy Run	PeachBotto	PeachBotto	Salem 1	Salem 2	Schuylkill	CT's				
Muddy R	Peach B 2	Peach B 3	Salem 1	Salem 2	Schuylk 1	CT's	Total	Average	Year	
								($/MWh)		Total
$6	$20	$20	$20	$20		$3	$357	9.0	1999	Incremental
$7	$20	$20	$20	$20		$3	$369	9.2	2000	Costs
$9	$19	$19	$20	$20		$3	$383	9.5	2001	million$
$12	$20	$20	$20	$20		$3	$401	9.9	2002	
$15	$20	$20	$20	$20		$3	$420	10.3	2003	
$18	$20	$20	$20	$20		$3	$442	10.8	2004	
$22	$21	$21	$21	$21		$3	$459	11.1	2005	
$27	$21	$21	$22	$22		$2	$480	11.5	2006	
$33	$22	$22	$22	$22		$2	$502	12.0	2007	
$40	$23	$23	$23	$23		$2	$526	12.5	2008	
$48	$24	$24	$24	$24		$2	$551	13.1	2009	
$51	$24	$24	$25	$25		$2	$571	13.5	2010	
$54	$25	$25	$26	$26		$2	$590	13.9	2011	
$56	$26	$26	$27	$27		$2	$611	14.3	2012	
$59	$27	$27	$28	$28		$2	$632	14.7	2013	
$62	$28	$28	$29	$29		$2	$654	15.2	2014	
$65	$29	$29	$30	$30		$3	$677	15.6	2015	
								($/MWh)		Margin
$14	$50	$50	$50	$50		$13	$608	15.3	1999	million$
$24	$58	$58	$59	$59		$22	$736	18.4	2000	
$40	$70	$70	$71	$71		$38	$928	23.0	2001	
$41	$74	$74	$75	$75		$39	$974	24.0	2002	
$42	$78	$78	$79	$79		$40	$1,024	25.1	2003	
$44	$82	$82	$84	$83		$41	$1,075	26.1	2004	
$45	$86	$86	$87	$87		$43	$1,125	27.2	2005	
$47	$90	$90	$91	$91		$44	$1,174	28.3	2006	
$48	$94	$93	$95	$95		$46	$1,227	29.4	2007	
$50	$98	$97	$99	$99		$47	$1,281	30.6	2008	
$52	$102	$102	$104	$103		$49	$1,339	31.8	2009	
$54	$108	$107	$109	$108		$51	$1,408	33.3	2010	
$56	$113	$112	$115	$114		$52	$1,483	34.9	2011	
$58	$119	$118	$120	$120		$54	$1,560	36.5	2012	
$60	$125	$124	$126	$126		$56	$1,641	38.2	2013	
$62	$131	$130	$133	$132		$58	$1,726	40.0	2014	
$64	$138	$137	$140	$139		$60	$1,817	41.9	2015	

Results of Monte Carlo Simulation
Weighted Average Revenue ($/MWh)

Case	Average	% Average
WHH-4	20.67	99.82%
1	20.72	100.07%
2	20.74	100.20%
3	20.71	100.05%
4	20.71	100.04%
5	20.69	99.92%
6	20.68	99.88%
7	20.66	99.77%
8	20.74	100.16%
9	20.71	100.03%
10	20.71	100.01%
11	20.71	100.05%
Average of 12 Cases	**20.70**	



PROPRIETARY INFORMATION

Docket Number R-00973953

Name of Document Exhibit WHH-7

Date Document Received 10-15-1997

DOCUMENT CONTAINS

PROPRIETARY INFORMATION

EXHIBIT WHH-8

PECO STATEMENT NO. 9-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PECO ENERGY COMPANY
FOR ISSUANCE OF A QUALIFIED RATE ORDER
UNDER SECTIONS 2808 AND 2812 OF THE PUBLIC UTILITY CODE

REBUTTAL TESTIMONY OF

WILLIAM H. HIERONYMUS

REGARDING MARKET PRICES FOR PECO ENERGY GENERATION

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

Q. Please state you full name and business address.

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

Q. Have you submitted testimony previously in this proceeding?

A. Yes. I submitted PECO Statement No. 9 and accompanying Exhibits Nos. WHH-l to WHH-5. My background and qualifications are set forth in Exhibit No. WHH-1 to that Statement.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to aspects of the testimony of various witnesses. On the subject of the effects of stranded cost recovery on competition, I am responding to the testimonies of IPL witness Brehm, "Environmentalists" witness Mendl, and OSBA witness Kalcic. On the subject of policy concerning the calculation of stranded cost I am responding to IPL witnesses Brehm and Lewellen. On the subject of the relationship between market prices and long run marginal cost I am responding to the IPL witnesses and to PAIEUG witness Falkenberg. On the subject of criticisms of the analysis of market prices that I sponsored in Statement No. 9 I am responding to Mr. Falkenberg and OCA witness La Capra.

For purposes of this proceeding I have accepted some of the criticisms made as being either valid or appropriate to use under the circumstances of this securitization proceeding. In consequence, I have rerun the model used in my earlier testimony and produced a new exhibit, Exhibit WHH-6, which is a revised version of Exhibit WHH-4 of that analysis. This new exhibit contains the inputs to PECO's stranded cost analysis that derive from my analysis. It has been provided to PECO for the purpose of quantifying the effects of the changes I have made.

The Effect of Stranded Cost Recovery on Competition

Q. Mr. Brehm asserts that if PECO and other Pennsylvania utilities are allowed to recover their stranded costs, and particularly if stranded cost recovery is based on projected market prices that are below long run marginal costs, then out-of-state competitors and competition will be harmed. Do you agree?

A. No. It is important, first, to be aware that competitive prices are based on short run marginal costs. They also may equal, and indeed will tend over the long term toward, long run marginal costs. However, at any point in time, the price in the market will be set by the short run marginal cost of the most expensive (in terms of marginal cost) generation required to meet load. This is basic economics. The reasoning, quite simply, is that all producers will wish to sell all output for which they can make a contribution to fixed cost and profit. Stated otherwise, the refusal to sell output when the market price is above marginal cost will reduce profits by the amount of such contribution that would have been earned on the output. Competition among sellers, all of whom face these same incentives, will drive the price down to the highest marginal cost of output demanded by consumers at that point in time.

Short run marginal cost is the variable operation and maintenance expense of producing an additional increment of output, including the variable fuel cost of production. It expressly does not include sunk capital costs that exist independently from the level of output. Nor does it include future costs that cannot be avoided by curtailing output. It also does not include other balance sheet costs such as regulatory assets.

Setting aside the extreme case of bankruptcy (which may increase short run marginal costs), the short run marginal costs of Pennsylvania utilities will not be affected by the level of stranded cost recovery (provided only that stranded cost recovery is not conditioned on continuing to operate all facilities irrespective of whether it is economic to do so). It follows that market prices for delivered bulk power in Pennsylvania will not be affected by stranded cost recovery. Neither competition, nor competitors will be injured.

Curiously, Mr. Brehm in a different context acknowledges that sunk costs have nothing to do with market prices. He uses the example of three firms with equal capability to produce output, one of which has a book cost of $2 billion, one a cost of $1 billion and one a cost of $0.5 billion. Each has the same market value because all would face the same prices for their output. Clearly, if the level of sunk cost does not affect prices, it follows also that the recovery of some portion of it outside of the generation market also will not affect prices.

Q. Mr. Brehm argues that in the past utilities may have kept open plant that should have been closed and asserts that PECO may be planning to keep open generating facilities that should be closed or at least not life-extended. Isn't it the case that keeping open uneconomic facilities can depress prices, injuring competitors?

A. In principle, yes. However, this also has nothing to do with stranded cost recovery. If in the past it was necessary to continue to operate uneconomic facilities in order to keep them in rate base, there would have been an incentive to operate them when the value to shareholders of keeping them in rate base exceeded any costs they bore from uneconomic operation. However, my understanding of the situation in Pennsylvania is that stranded cost recovery is not contingent on the continued operation of the facilities with which it is associated if those facilities are rendered uneconomic by virtue of the transition to competition. A Pennsylvania utility will have no incentive to keep open those facilities that do not earn enough in the marketplace to cover their avoidable costs. In this context, avoidable costs include any fixed O&M and capital expenditures that would be required to keep them open. Hence, stranded cost recovery will not create any incentive to keep open generating stations that economically should be closed.

Q. Mr. Brehm specifically objects also to stranded cost recovery that reduces PECO's remaining costs of generation to below LRMC. Are there any competitive implications from basing stranded cost quantification and recovery on price levels below LRMC?

A. No. At a latter point in my testimony I will discuss Mr. Brehm and Mr. Falkenberg's assumption that market prices should equal LRMC. However, I will deal here with the narrower question of whether basing stranded cost recovery on forecasts of market prices below LRMC does harm to competitors.

Mr. Mendl makes a related point, asserting that if PECO is allowed excessive stranded cost recovery it either will earn excess profits (in effect, recover the same costs from the market and from stranded cost recovery provisions) or will injure competitors by selling at below market prices. Both Mr. Brehm's and Mr. Mendl's competitive concerns are mis-placed. If, hypothetically, PECO is granted a too high stranded cost recovery (and it is able to recoup the allowed stranded cost under its price cap), shareholders will have benefited. However, this will not harm competitors. It will not be in PECO's interest to sell at below market prices irrespective of whether it recovers all, more than, or less than its stranded costs. PECO's interest will be in maximizing returns to shareholders and, as is the case with competitive firms generally, this is not accomplished by giving away its output at below market prices. This is true whether the market price turns out to be above or below LRMC.

This actually is simply common sense. Suppose that the City of Boston decides that it is in its interest to build a football stadium in order to retain its NFL team. Does this mean that ticket prices will be less than they would be if the team had paid for the stadium itself? Presumably not, since it will set ticket prices at the profit maximizing price. An even better analogy would be if a steel company acquired a facility at what turned out to be a below market price. Would it sell steel any cheaper as a result? No, it would sell steel at the market price and simply be more profitable because its book costs were lower.

The sole exception to this common sense rule has to do with predation. If PECO is "enriched" by stranded cost recovery (or less impoverished by some amount of stranded cost recovery), it arguably will be better able to bear the profit loss caused by its predatory pricing than if it had less deep pockets. However, the economic case for predation is very limited. In order to profitably engage in predatory pricing it is necessary to be able to drive competitors out of the market and keep them from returning. Assume, hypothetically, that PECO chose to drive down the price of power in Pennsylvania below the competitive level. PECO itself would lose money that it could have made at the competitive price. IPL (and other out-of-state utilities) might indeed choose to sell their output elsewhere. New generators might decide not to build plants for the Pennsylvania market. However, as soon as PECO began trying to sell power at above the competitive price (as it would have to be able to do if it was to recover the profits lost by starting the price war), IPL would turn around and sell into Pennsylvania, entrants would seek to build to serve this high priced market, and the forces of supply and demand quickly would drive prices back down to the competitive level. In my opinion, it is highly unlikely that predatory pricing will be profitable in US electricity markets for any firm.

"Tobin's Q", Cost of Service Regulation and the Justification for Stranded Cost Recovery

Q. Mr. Brehm opposes PECO's securitization claim on the basis that its stranded cost calculation is fundamentally unfounded. Can you first summarize briefly your understanding of his argument?

A. Yes. Mr. Brehm begins with the basic proposition that (at least in the long run) the market value of an unregulated firm tends toward the replacement cost of its assets. By replacement cost, he means (as is discussed more fully by Dr. Lewellen, IPL's other witness) the cost of the optimum facilities capable of producing the same outputs, not the cost of new in-kind replacement of its assets. To distinguish the two, I will refer to this as optimum replacement. Thus, "Tobin's Q", which is simply the ratio of the market value of the firm to the replacement cost of its assets, trends toward unity.

He then asserts that proper regulation (and, he would argue, actual regulation over much of this century) would base the regulated value of the firm on optimum replacement cost. That is, proper regulation would, according to his thesis, allow a market return on the optimum replacement cost of assets, not their book value or in-kind replacement cost. Hence, proper regulation also results in a "Tobin's Q" of one. He observes that there is no necessary correspondence between the accounting book cost of the firm's assets and optimum replacement cost (hence, in his world, replacement cost "rate base").

Stranded costs are costs arising from the movement from regulation to competition. Since the firm's market value is, and the value of a properly regulated utility also is (or should be), its "Tobin's Q equals one" optimum replacement cost, he could have said that it is *per se* impossible for stranded cost to occur. While he never quite reaches this point, he does say that stranded cost recovery should be allowed only for "financial viability", which he defines as a circumstance in which the transition to competition will drive the value of assets below their optimum replacement cost. While I hesitate to put words in his mouth, this would seem to suggest that he would accept that PECO should receive stranded cost recovery if, but only to the extent that, the sudden onset of competition leads to market prices below long run marginal cost.

Q. Do you agree with his analysis?

A. No.

Q. Why do you disagree?

A. Quite simply, his standard for defining stranded cost is at variance with the term as used generally and specifically in the statute that governs this proceeding. Stranded cost is the difference between the revenues that would have been earned under continuation of the previous regime of regulation and those that will be earned when some utility functions are opened to competition and revenues are determined by the marketplace. Equivalently, they are the value of assets under regulation versus the value of those same assets under competition. As defined in the Pennsylvania statute, "'Transition or stranded costs' [are] an electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability...which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market...[These include the unrecoverable part of] net plant investments and costs attributable to the utility's existing generation plants and facilities..."

PECO's revenues, like those of virtually every regulated electric utility in the US, are based on cost of service ratemaking. The cost basis for cost of service is rate base. Rate base is not, as Mr. Brehm would have it, optimal replacement cost, but historic book cost. While Mr. Brehm asserts that historic cost-based ratemaking is "not traditional regulation as it has been practiced during the vast majority of time since the early 1990's," this is highly misleading, since it has been traditional regulation during the vast majority of the past 50 years. Fair value ratemaking lost out to historic cost in most jurisdictions during the Forties and Fifties. In any case, stranded costs for Pennsylvania utilities must be computed in relation to what would have been recovered under existing Pennsylvania regulation. As stated in the Pennsylvania Public Utility Code, "The value of the property of the public utility included in the rate base shall be the original cost of the property when first devoted to the public service less the applicable accrued depreciation... (66 Pa. C. S. §1311(b)).

Much of Mr. Brehm's testimony goes to why cost of service ratemaking based on original cost rate base is inefficient and, perhaps, inequitable. I have considerable sympathy for his view that cost-of-service regulation has serious drawbacks. Indeed, the movement toward competition and generation price deregulation owes much of its support to criticisms of the theory and efficacy of traditional regulation based on cost of service and original cost ratebase.

However, the fact is that the revenues and values consistent with this traditional regulation form the basis from which stranded costs are measured and it is the effect of departing from that regime that stranded cost recovery is intended to compensate. In short, Mr. Brehm seeks to wish the problem away by assuming, counter-factually, that the regulatory regime from which PECO is departing is based on optimal replacement cost, which he also assumes will approximate the market value of its output and assets. If this position were factually true, then there would be no stranded cost problem in Pennsylvania or anywhere else in the US.

Long Run Marginal Cost as a Measure of Market Prices

Q. Mr. Brehm's concept of market value assumes that market prices will tend toward long run marginal cost. Mr. Falkenberg's estimate of stranded generating costs assumes that prices will be set at long run marginal costs. Do you agree with these positions?

A. I agree that in the long run prices must average about long run marginal costs if new generation is to be built and receive the expected level of economic return. However, to the extent that these positions assume that prices go immediately to LRMC, or that by the year 1999 prices in PJM will be at LRMC levels as defined by the cost of combined cycle units (Mr. Falkenberg's assumption), I disagree.

Q. Why do you believe that prices will be below LRMC in the near term?

A. Let me first begin with why it is that prices will have to go to LRMC eventually, given that they actually are set by short run marginal cost (SRMC). Let us suppose that SRMC-determined prices initially are below LRMC. At such prices, building new plant cannot be justified economically. Hence, as load grows and (perhaps) old plant is retired, more and more expensive existing facilities are used more and more of the time. Average prices rise and, ultimately, may rise to where it is profitable to build new plant. At this time, prices have reached LRMC. Were they to rise still higher, more new plant would continue to be built until prices fell to the point at which new plant would no longer earn a market rate of return. Thus the LRMC level of prices is both a floor and ceiling for the expected level of prices, around which actual prices will fluctuate (and from which they may depart for substantial periods if expectations prove wrong).

This discussion assumes a single market price and a single type of capacity. In PJM, there will be two important types of prices – energy and capacity – and two economically important types of capacity in the near term – combustion turbines (CTS) and gas-fired combined cycle units (GCCs).

All of the analyses of PECO's three sets of models reflect the fact that in PJM, and in the US generally, there is a surplus of baseload capacity. While GCCs may be the most economic type of baseload and near-baseload capacity to build today, they cannot generally compete in energy markets with coal-fired and nuclear capacity. When they do run, SRMC-derived prices will afford only a small margin over fuel costs much of the time, resulting in only a small contribution toward fixed costs. CTS will earn an even smaller margin, but cost less. Hence, initially, they may be less unprofitable that GCCs.

Turning now to the capacity market, the proposed PJM rules, like the existing rules, require that load serving entities have sufficient capacity entitlements to meet their peak loads including a mandated reserve margin. In PJM and most of the rest of the US, there is a surplus of capacity. In the areas that PHB has studied, the capacity surplus lasts another 3 to 7 years. During the surplus period, there is "too much" capacity chasing "too little" demand. Prices need only be high enough to justify keeping open sufficient existing capacity to meet demand. Even this is an overstatement, since owners may keep open units that cannot cover shutdown costs in the near term if the units will be profitable enough in the longer term to justify the temporary loss. The main point is that prices in the capacity market need not be high enough to justify building a peaker (CT), much less the GCC that Mr. Falkenberg uses from 1999 in his stranded cost analysis.

Of course, over time the excess capacity margin will erode and new capacity will be required. New capacity will be required in the capacity market well before it is required in the energy market. This does not mean, inherently, that CTs will be built rather than GCCs. If the higher level of operating contribution earned by GCCs in the energy market are enough to cover the cost difference between GCCs and CTs, then GCCs will be built.

Ironically, Mr. Falkenberg faults the PHB analysis for building GCCs when the market price was not high enough to justify building them. This is ironic in that he also assumed that GCCs would be built (assuming, without justification, that they would set prices as early as 1999). He was correct that our analysis was internally inconsistent. This is because we made the same (incorrect) assumption that he makes: that GCCs would be the most economic capacity to build as soon as any capacity is needed. I correct this inconsistency in the analysis discussed below.

To summarize, Mr. Brehm is right that market prices tend to equal long run marginal cost. Mr. Falkenberg is right that, ultimately, prices in PJM must be high enough to economically justify building the lowest cost type of baseload and near baseload capacity. However, in the near term they do not have to be high enough to justify building any new capacity. Further, the economics (as well as lead times) indicate that the early units built will be built primarily for the capacity market and will be CTS. Only later will prices have to rise high enough to economically justify building the GCCs that Mr. Falkenberg uses in his analysis.

Q. Mr. Brehm also criticizes PECO for estimating the value of its generation based on the net present value of margins, referring to such estimates as "wild analytical guesses". Is his criticism valid?

A. No. His first criticism is that estimating the value of a regulated business based on future earnings is circular. While true, this is irrelevant, since the net present value analysis is designed to produce the market value of the generating assets, not their regulated value which (precisely because of this circularity) is observable from the company's books.

His more substantial criticism, also made by Mr. Falkenberg, is that forecasts of future costs and revenues are highly uncertain. I agree, though I would note that the forecast of margins is less uncertain than the forecast of either fuels costs or revenues. Whether the task is daunting or not, it is required by the relevant Pennsylvania statute which calls for stranded costs to be determined on a net present value basis over the life of the assets. Further, the task is essentially unavoidable. Mr. Brehm would have us believe that this could be avoided by his *concept of optimum replacement cost. But the use of optimum replacement cost* begs a number of questions, most of which can be summarized as, "how many megawatts of combined cycle plants and combustion turbines is PECO's existing generation worth?" The answer to this question can only be, "As many megawatts as yield the same net present value of margins."

Response to Comments on PHB Market Price Analysis

Closure of PECO Units

Q. Both Mr. La Capra and Mr. Falkenberg comment that the prices derived in the PHB study are not sufficient to justify keeping open a sizable fraction of PECO's generating capacity. More specifically, Mr. Falkenberg identifies 2739 MW of uneconomic capacity. Are these statements correct?

A. Only partially. Mr. Falkenberg's calculation is traceable to Mr. Hill's Exhibit TPH-4 which summarizes the net present value of contribution margin. In fact, only Cromby 2, Delaware and Schuylkill are uneconomic on an avoidable cost basis. These add up to only 617 MW that are uneconomic on a net present value basis. In the analysis included in this rebuttal testimony, I have assumed that these units are closed prior to 1999.

Q. Assuming that these units in fact are uneconomic, and should be closed, what will be the effect on your analysis?

PECO STATEMENT NO. 6-RJ

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

REJOINDER TESTIMONY

OF

WILLIAM H. HIERONYMUS

Regarding the Energy & Capacity Cap and Competition Under the Partial Settlement of PECO Energy Company's Proposed Restructuring Plan

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DOCKETED
OCT 22 1997

REJOINDER TESTIMONY OF WILLIAM H. HIERONYMUS

Q. Please state your name and business address.

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

Q. Have you submitted testimony previously in this proceeding?

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

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

A. I am responding to assertions made by PECC witnesses Steven A. Mitnick and Jeanine Hull and MAPSA witness Donald E. Johnstone concerning the Partial Settlement. The main focus of my testimony is on the alleged inadequacy of the Energy and Capacity Cap (ECC). I also will address (1) the consequences should it turn out that the ECC is below the delivered cost of the generation component of electricity, and (2) the assertion that the ECC should be raised to allow for the marketing costs of competitive marketers.

I will not respond to assertions by some of these same witnesses that the Partial Settlement allows PECO to overrecover the intended amount of stranded cost. This is the subject of other PECO witnesses' testimony and, for purposes of my testimony, I will assume that the CTC/ITC recovery in the Partial Settlement is at the appropriate level, given the other elements of the Settlement. I will, however, address briefly the assertion that production-related administrative and general expenses (A&G) and uncollectable accounts expense should be removed from charges for the transmission and distribution function and used to increase the ECC. Lastly, I will address briefly Mr. Mitnick's statements concerning "predatory pricing" by PECO.

Q. Your earlier testimony in this proceeding sponsored the PHB market price forecast. Do you continue to believe that your forecast is the most reasonable forecast for establishing PECO's stranded costs?

A. Yes. Moreover, as I noted in PECO Statement No. 6-R, this forecast was based on the most recent fuels price forecast made by DRI. The principal alternative forecast available, the US Department of Energy's EIA forecast preferred by some of the intervenors in the proceeding results in a materially lower forecast of electricity prices and a higher forecast of stranded cost. I conclude from this that, if anything, the forecast that I sponsored is conservative relative to the energy price forecast information that is available.

Q. Before proceeding to your more specific comments on intervenor testimony, do you have a general characterization of the issue that they raise?

A. Yes. These witnesses accept, for the purpose of their testimonies, the appropriateness of recovery of $5.461 billion in stranded cost via the CTC/ITC mechanism. Additionally, they agree that the 10 percent rate cut should be retained and that the overall price cap is appropriate. Within the confines of this agreement, they seek a basis for reconfiguring the three components of the overall cap, decreasing T&D and CTC/ITC charges and increasing the ECC.

It is axiomatic in economics that there is no such thing as a free lunch. In negotiating the settlement, there clearly had to be a tradeoff between the level of the overall cap, CTC recovery, the ECC and, to a lesser extent, the payment for regulated electric distribution company (EDC) services. Intervenors' main complaint seems to be that this tradeoff resulted in an ECC that is too low and allege that it can be increased without raising the overall cap. However, it is also clear that they believe that the Partial Settlement should not have given as much emphasis as it did to the overall cap and the resulting level of customer savings. At page 20 of his testimony, Mr. Mitnick outlines the way in which he believes the overall cap should have been calculated: First, determine all costs directly rated to T&D. Second, set the CTC/ITC to recover the Commission-determined allowed stranded costs. Third, set an ECC sufficient to meet the needs of competing suppliers. "Last, any residual should go to the customer in the form of rate decreases..."

Q. You stated that intervenor witnesses have accepted, for the purpose of their testimonies, the appropriateness of recovery of $5.461 billion for stranded cost. Doesn't PECC witness Hull provide an alternative market price forecast in her Table 1?

A. This appears to be the case. However, it is not clear that her market price forecast should be taken to be anything other an illustrative example for purposes of discussing the alleged problems of suppliers seeking to sign long term contracts. If it is intended to be an actual forecast it lacks sophistication in that her presentation assumes that prices change by the rate of inflation only.

Indeed, Ms. Hull simply begins with a 1999 price of $34/MWh and escalates it at $1/MWh per year.

Q. Intervenor witnesses adjust the market prices you have forecasted for line losses and gross receipts taxes (GRT) in comparing them to the generation price cap for purposes of determining whether retail competitors will be able to compete with PECO's standard offer. Do you agree that these adjustments are appropriate?

A. Yes. PECO and its competitors will have to include line losses and GRT in their retail prices. It is not yet certain whether it is necessary to gross up the capacity (as opposed to energy) component for line losses. This depends on evolving Pennsylvania-New Jersey-Maryland (PJM) Interconnection rules. If the capacity requirement, which all witnesses accept to be 118 percent of load, is applied to load without a gross-up for losses, then this adjustment is inappropriate. However, for purposes of my testimony, I will assume that the line loss adjustment is appropriate for both energy and capacity.

Q. Both Mr. Mitnick and Mr. Johnstone adjust energy prices to reflect differences between the all-hours price that PECO derived from your market energy price analysis and an energy price reflective of customers' load profiles. Do you agree with this adjustment?

A. In concept, yes. However, these witnesses employ very different estimates. Mr. Johnstone increases the all-hours price by 0.26 percent. This is based on his acceptance of PECO witness Sundermeir's calculation of a 0.26 percent adjustment for the residential class. This class should be broadly representative of the effect of load shape on wholesale electric energy prices for PECO as a whole.

Mr. Mitnick uses a much higher adjustment, 8.8 percent. Based on the relative flatness of the prices in my market rate analysis, an 8.8 percent adjustment, more than 30 times Mr. Johnstone's adjustment, is implausible.

Q. **Taking into account line losses and GRT and the energy cost adjustment you have been discussing, is it the case that the ECC is sufficient to recover the busbar purchase costs of competing generators?** NOT

A. Generally, yes. Exhibit WHH-9 shows the relationship between the ECC and the cost of energy and capacity using the market prices that I derived based on both the DRI and EIA fuels forecasts. As Mr. Hill explains, the system average ECC has been adjusted to eliminate the 32 LILR and EER customers. Because these customers are currently on either non-standard discounted or interruptible rates, their ECC is uniquely low and biases the overall ECC downward. This adjustment increases the ECC by between 0.1 cents and 0.35 cents over the period of the analysis.

Market prices of energy and capacity are shown for aggregations of customers with load factors ranging from 60 to 100 percent. All calculations assume a 7 percent loss factor for both energy and capacity and include a 4.4 percent GRT. Energy prices are increased relative to the all-hours price by 0.26 percent for the 60 percent load factor customers, trending down to zero for 100 percent load factor customers. Capacity costs included in the calculation include losses, GRT and the 18 percent reserve requirement and differ according to the load factor of the customer.

For both price forecasts and for all load factors, the average ECC exceeds the average market cost of energy over the period on both a simple average and present value basis. For 100 percent load factor aggregations, the ECC is above the market price in all years. For 80 percent load factor aggregations, the ECC equals or exceeds the market price in all years in the EIA-based forecast; for the DRI-based forecast, the market price is .01 cents and .04 cents higher than the ECC in 2000 and 2001 respectively. For 70 percent load factor aggregations, the EIA-based price is 0.05 and 0.12 cents above the ECC in these same two years; in the DRI-based forecast it is 0.08 and 0.17 cents above. For the 60 percent load factor aggregations, the market price exceeds the ECC in 2000-2003 in amounts ranging from 0.02 to 0.29 cents in the EIA case and by 0.13 to 0.33 cents in the DRI case. The market price also exceeds the ECC by 0.07 cents in 2005 in the DRI case. In all other years the market price is lower than the ECC.

Q. Why have you focused on load factors ranging from 60 percent up to 100 percent?

A. One of the competitive tactics that competing retailers can expect to use is to assemble aggregations of customers with high load factors, "cherry-picking" within rate classes those customers who can be served at lower costs. PECO informs me that its overall load factor is about 65 percent. The comparison I have made is intended to portray the range of aggregations that they may be able to achieve.

Another

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Q. Do you agree that there will be little if any headroom between market generation costs and the ECC during the first several years of the transition to competition?

A. Yes, but this is necessary if the overall cap is to fulfill its functions of assuring rate decreases and recovering the appropriate level of stranded costs.

Q. Why is a tight cap necessary to protect customers from over-recovery of the allowed CTC/ITC?

A. A tight cap ensures that the CTC is not overrecovered even if busbar electricity prices are higher than the level that was forecasted when the CTC was agreed. This is best understood by illustrating what happens if the market price of generation is above or below the forecasted level. First, assume that the price is higher. PECO's generation will receive higher than forecasted revenues. Based on this alone, it would over-recover the agreed amount of stranded cost since the CTC/ITC payment is based on a forecast of market revenues that turned out to be too low. However, if the price cap is tight, it will be too low to allow PECO's regulated customer service (EDC) activity to recover its purchased generation costs. That is, if the generation price is $1 per MWh higher than the forecast, generation will receive $1 per MWh more for every MWh produced but the regulated EDC activity will have to pay an uncompensated $1 per MWh for every MWh sold. Under these circumstances, generation's gain will be approximately offset by the EDC's loss.

Now assume that the market price of generation is below the forecasted level. Clearly, the value of PECO's generation is less than was anticipated. This means that PECO is taking a greater than loss on its generation than was intended. Unlike the case with higher than anticipated prices, there is no assurance that higher than forecast prices from the EDC will offset the generation loss. The EDC can purchase wholesale energy at less than the expected price. If it still can charge the price cap, the higher profits of this activity will approximately offset the revenue shortfall of PECO's generation. However, the Partial Settlement requires that customers electing service under the price cap be charged a market price for electricity, notwithstanding the cap. Even if this provision did not exist, PECO would be unlikely to be able to pass through an above market price, since competition would erode the base of customers electing service under the price cap were it to attempt to do so.

Conversely, if the cap is not tight, then customers are not protected from market prices that are higher than were forecasted, since the higher price can be passed through without violating the cap. If market prices are below the ECC, PECO likely would not be able to charge the full ECC amount, since competition would undercut the attempt. Hence, an ECC that is above the cost of wholesale electricity will neither protect consumers from overrecovery nor allow the company to recover any CTC amounts that have been shifted to the ECC.

Q. A main theme of the intervenor witnesses is their belief that the ECC must be high enough to allow competing generators to recover their marketing and administrative costs. Can you please summarize the nature of their argument?

A. There are three themes. The first is Mr. Mitnick's argument that customer service costs should be unbundled from T&D and offered separately to competing retailers who could use them or self-provide them. The second relates to the need for an ECC sufficient to pay for competing retailers' marketing and other costs as well as a profit on the retailing activity. The third, raised by PECC witness Hull, is the need for the ECC to be high enough that competitors can profitably undercut PECO's price capped offer.

Q. Regarding the first theme, is the issue of unbundling appropriate in considering the Partial Settlement?

A. No. Unbundling is a reserved issue that is not a subject of the Partial Settlement. This will be taken up by the Commission either in a later phase of this proceeding or in a separate generic proceeding. If at that time the Commission determines that unbundling some customer service functions is appropriate it can make the necessary modifications.

Q. Regarding the second theme, is it appropriate to increase the ECC to cover retail competitors' selling, general and administrative (SGA) costs and profits?

A. No. Assuming that the Partial Settlement in fact contains appropriate allowances for CTC/ITC and T&D, increasing the bid cap to fund retail competitors SGA and profit would not be in customers' interest.

I find it most remarkable that the proponents of retail access contend that customers should pay higher prices as a result of the introduction of retail competition. The purpose of introducing competition is to reduce customer costs and improve product quality, not to add an additional cost of service to be recovered on a cost-plus basis. If retail, as distinct from wholesale, competition has merit, it is because the newly competing retailers can provide a better product to consumers than the former franchise monopoly or provide the same product at a lower cost. If entrant retailers (including PECO affiliates) cannot add value to customers, then it is entirely appropriate for customers to elect to stay with the EDC supply.

Q. **Do you agree with the assertion that entrants cannot compete successfully without an ECC that pays for their SGA and profit?**

A. There is too little evidence to know how successful entrants will be. However, there is reason to believe that entrants will succeed without such allowance. The newly emerging retailers have numerous ideas for how to provide a better product at lower prices. These include bundling various utility and non-utility services together, "customer side of the meter" services, pricing innovations such as "weather-proof" bills and branding strategies that increase the perceived quality of the product.

Power marketers also have shown considerable creativity in making money through arbitrage despite that they are both buying and selling at wholesale market prices. Enron is the most successful power marketer in the country. Yet according to the type of calculations proffered by these witnesses, it should be making a loss since the market price at which it buys and the market price at which it sells make no explicit allowance for SGA expense.

Q. **Mr. Johnstone asserts on page 7 of his testimony that "retail business costs" are likely to be in the range of 4.8 mills per kWh. Do you have any information that puts that estimate in perspective?**

A. Yes. Remember that entrants can choose which customers they will serve. Whatever may be the ECC, they will choose to serve only those customers that are profitable. The evidence in California, ~~which is planning full retail access by~~

January of 1998, is that the large customers and multi-site customers are the main focus of entrants. Other marketers, including members of PECC, are going after national and regional accounts -- for example, seeking to be the energy provider for a chain of department stores or fast food restaurants.

The cost per kWh of retail marketing and services to large and self-aggregating customers is very much less than the cost of accessing smaller customers. One benchmark is from the United Kingdom. When the UK electricity industry was restructured and privatized, there were price caps placed on the retailing activities of the incumbent distribution utilities. These typically were about 3 mills for the small customers (who did not have retail access) and 0.3 mills for large (peak load of 1 MW or more) customers that had retail access. Three years later, the regulator studied the results of competition for accessible customers and found that the cap was unnecessary since competition was constraining the gross margin (covering SGA, customer service and profit) to below the 0.3 mill per kWh cap. While the data the UK regulator relied on is not publicly available, this conclusion means that the competitive margin was less than 0.3 mills, an order of magnitude below Mr. Johnstone's estimate.

Q. Ms. Hull states that entrants will have a difficult time competing unless they can sell power at a price at least 5 percent below PECO. Assuming that this is true, should this concern the Commission?

A. Not significantly. The importance of competition is not that competitors succeed, but that their presence disciplines market prices and offerings. Indeed, Ms. Hull admits that entrants will achieve at least some market penetration. Further, assuming that Ms. Hull is right and that the Commission de an artificial price incentive to switch suppliers, where is the money to come from? Intervenors' acceptance that the overall price cap should not be raised leaves only one source: PECO's shareholders. I can think of no public policy purpose served by requiring that PECO subsidize its competitors.

Q. Mr. Mitnick claims that the continued dominance of AT&T in the long distance market demonstrates the power of incumbency and the need for the Commission to take action to assure competitive entry. Do you agree?

A. No. It is evident that competition in the long distance market has flourished even without artificial subsidies to entrants. Further, AT&T's retention of the largest share of the market is not evidence of the need for artificial competitive stimulus. Indeed, the FCC has chosen to deregulate AT&T's prices, precisely because competition had achieved the desired effect of disciplining prices notwithstanding that AT&T had retained about half of the market.

Q. The main source that intervenors use for higher ECCs is a reduction in the allowance for T&D. What are the main adjustments that they propose be made?

A. The main adjustments are the removal of what is alleged to be generation-related overheads and uncollectable account expense.

Q. Beginning with the production-related overheads, is it appropriate to remove any such overheads that are included in T&D and transfer them to the ECC?

A. No. As a factual matter, I note that PECO witness Clemmer shows that overheads are allocated properly. Even if, as intervenors allege, overheads are underallocated to generation, and if the Commission were to decide to correct this alleged defect, ~~the appropriate place to put them would be in an~~ increased CTC.

The market value of PECO's generation is the difference between market prices and generation costs. If such costs are increased by changing the allocation of overheads used in the stranded cost analysis, then stranded costs (and hence the need for CTC coverage) increases on a dollar for dollar basis. This was made clear by the difference between PECO's direct and rebuttal calculations.

Mr. Johnstone appears to recognize this obvious fact. Mr. Mitnick and Mr. Reising do not. Indeed, Mr. Mitnick proposes to increase the ECC for all generation A&G, including that which has been included in the stranded cost analysis.

Mr. Mitnick recognizes that the costs of running a generating unit includes overhead costs. He also states that efficient producers must earn enough over time to cover their overhead costs if they are to survive. I agree with both of these statements. However, he errs in concluding on that basis that the ECC should be increased by the amount of PECO's generation A&G. He cannot have it both ways, assigning production A&G to PECO's generation function and to the ECC. If production-related overheads are indeed an avoidable cost of generation and should be charged to PECO's generation function, then they, along with fuel and other avoidable costs such as O&M expense, must be subtracted from PECO's generation revenues in arriving at the contribution to capital costs that is the basis for determining the value of its generation. Dollar for dollar, an increase in allocated overheads reduces that contribution, thereby increasing stranded costs.

Conversely, consider the market cost of generation, to which Messrs. Mitnick and Reising seek to add these costs in arriving at the ECC amount. The market price of wholesale electricity is the short run marginal cost of generation plus the market cost of capacity. Overheads are not included in the short run marginal cost of energy. This is "econ 1" and was not disputed by any of the market price witnesses in this proceeding.

Overheads do play a role in setting the capacity price. In all of the market price studies, the capacity price was, by early in the next decade, determined by the cost (net of energy market profits) of an efficient entrant. In some analyses, this was a new combined cycle unit. In others, including mine, it was the cost of a new combustion turbine. It is the overheads (A&G) of that efficient new unit, not the overheads of PECO's existing units, that is factored into that calculation. Again, this method was used by all of the market price witnesses and was not, and cannot validly be, disputed.

Q. Intervenor witnesses also single out uncollectable account expense for removal from the T&D element of the rate cap and transfer it to the ECC. Do you agree that this is appropriate?

A. No. Shifting uncollectables to the ECC could be appropriate if all retailers were likely to bear the same expense for uncollectable accounts. In that case, PECO would avoid incurring uncollectable expense pro rata as it lost load to competitors. However, this is very unlikely to be true factually. PECO is the supplier of last resort, responsible for maintaining universal service at existing

cc

not accurate

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levels. Its competitors have no such obligation and will seek to avoid serving customers that are credit risks.

Q. Ms. Hull cites as evidence that your forecast of prices is too low the fact that the prices are not high enough to support construction of an efficient new combined cycle unit. Please comment.

A. Ms. Hull is simply citing a result of my analysis, which was that, based on the forecast costs that I used, a combustion turbine was a marginally more cost-effective new plant addition in PJM than was a combined cycle unit. Had I forecast slightly different relative economics for these two technologies, I would have reached a different result and built mostly combined cycle units. There would have been little if any change in my forecast of market prices.

In any event, Ms. Hull is incorrect in relating this issue to the size of the ECC. The choice of what technology is most cost effective is determined by the prices in the wholesale electricity market. It is not causally linked to competition in retailing, and hence is not related to any purported effects of the ECC.

Q. Ms. Hull also testifies that competitors will have difficulty making long- term retail sales that are competitive with the ECC. Please comment.

A. I expect that competitors will have difficulty making long-term retail sales under any reasonable circumstances. Certainly the experience with the competitive long distance communications market is that customers elect terms of service that allow them to switch suppliers with little cost or notice. Cellular phone service tends to be on a one year contract basis, despite the fact that the up-front cost of a heavily subsidized cellular phone must be amortized by the

ECC = 50%

60%

MB > 2000-2003 for 60%

supplier. In the UK nearly all competitive retail electricity contracts are for one year.

Q. What do you conclude from this?

A. The inability of suppliers to sign up customers to long contracts is not due to any deficiency in the ECC. It also is of little practical significance to the development of competition.

Q. At pages 28 to 30, Mr. Mitnick makes various assertions about PECO engaging in predatory pricing and seeks to relate such actions to the proposed Partial Settlement. Please comment.

A. While meaning no disrespect to Mr. Mitnick, I find his whole discussion incomprehensible and disjointed. However, I will attempt to respond.

Predatory pricing occurs when a firm sells below its variable costs in order to drive out a competitor, permitting it to then raise prices and recover its temporary losses. Mr. Mitnick makes no showing that PECO will be selling generation at below its variable cost. He cannot, since the market rate forecasts show clearly that PECO's variable costs are below the market prices that he is comparing to the ECC. Nor can he show that its retail offerings are below variable costs. The CTC recovery is not a variable cost. Most of T&D is non-variable. Hence, the bundled price cap also is well above variable cost and non-predatory.

Mr. Mitnick then discusses the value of a hypothetical option to exclude competitors. I simply cannot fathom what he is talking about. In any event, the value of maintaining market share to PECO is limited, precisely because the

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CTC is intended to protect its recovery of strandable costs even when it loses market share.

Mr. Mitnick then discusses the ECC and the use of securitization receipts to discourage investment in generation. The former is irrelevant for the reasons I have explained in the context of Ms. Hull's testimony: that the decision to build generation relates to competitive conditions in the bulk power market, not the retail market. The latter also is irrelevant, unless one assumes that PECO will invest its capital in building uneconomic generation in order to preempt entry. This would not be a sound business strategy. In any event, PECO's use of securitization proceeds are heavily circumscribed by the proposed QRO attached to the Partial Settlement.

Lastly, Mr. Mitnick muses about the possible exercise of market power, with no analysis whatsoever to show that PECO has market power or could gain it by making further investments in generation.

To summarize on this point, the Partial Settlement will not cause PECO to engage in predatory pricing. There is no reason why securitization should cause PECO to make uneconomic generation investments even if funds could be used in that manner. There is no evidence whatsoever that PECO can preempt other firms from making economic investments in new capacity. Nor is there any evidence of potential market power. The whole anti-competitive argument made in this section of Mr. Mitnick's testimony is unsupported speculation.

Q. Does this conclude your testimony?

A. Yes.

Comparison of System Average Generation Rate Cap
to Retail Energy & Capacity Costs
¢/kWh

Year	Settlement Energy & Capacity Cap	Settlement Cap Adj To Eliminate LILR & EER Customers	PHB Wholesale Price All Hours	PHB-DRI Wholesale Prices Adj To Average Retail 60% LF	70% LF	80% LF	100% LF	PHB-EIA Wholesale Prices Adj To Average Retail 60% LF	70% LF	80% LF	100% LF
1999	2.80	2.90	2.20	2.68	2.62	2.58	2.51	2.69	2.63	2.59	2.53
2000	2.80	2.90	2.44	3.08	2.98	2.91	2.80	3.05	2.95	2.88	2.77
2001	3.20	3.33	2.75	3.66	3.50	3.37	3.20	3.62	3.45	3.33	3.15
2002	3.50	3.66	2.88	3.83	3.66	3.53	3.35	3.75	3.58	3.45	3.27
2003	3.70	3.87	3.02	4.00	3.82	3.69	3.51	3.89	3.71	3.58	3.39
2004	3.97	4.17	3.16	4.17	3.99	3.86	3.66	4.03	3.85	3.71	3.52
2005	4.07	4.28	3.30	4.35	4.16	4.02	3.83	4.19	4.01	3.87	3.67
2006	4.77	5.04	3.44	4.53	4.34	4.19	3.99	4.36	4.17	4.02	3.82
2007	5.37	5.70	3.58	4.72	4.51	4.36	4.15	4.55	4.35	4.20	3.98
2008	5.57	5.92	3.73	4.91	4.70	4.55	4.33	4.74	4.53	4.38	4.16

2.75

No CAP

.16 = .3 @ 60% LF → 3.65

2.65 + .065 = 2.75

2.65 ~~2.65~~ = 3.