OCA STATEMENT NO. 2

8/25/97

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PENNSYLVANIA	:	
POWER & LIGHT COMPANY FOR	:	
APPROVAL OF ITS RESTRUCTURING	:	
PLAN UNDER SECTION 2806 OF THE	:	DOCKET NO. R-00973954
PUBLIC UTILITY CODE	:	

DIRECT TESTIMONY

OF

DOUGLAS C. SMITH

On Behalf of:

OFFICE OF CONSUMER ADVOCATE

JULY 1997

Introduction

Q: PLEASE STATE YOUR NAME, CURRENT OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Douglas C. Smith. I am a Senior Utility Analyst at La Capra Associates, 333 Washington Street, Boston, MA 02108.

Q: PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I received a Bachelor of Science degree in Mechanical Engineering from Brown University, Providence, Rhode Island, in May, 1986. I joined the Vermont Department of Public Service ("the Department") as Power Cost Analyst in 1986, and was promoted to the position of Electrical Planning Engineer in 1988. My responsibilities at the Department included the examination of electric utility power costs for ratemaking purposes, the analysis of short and long term power purchases, and other electric utility planning analyses.

Since joining La Capra Associates in 1991, I have worked for a range of clients in the energy industry, including regulated utilities, state regulatory agencies, non-utility power producers, and customers. I have performed dispatch simulations of numerous electric utility systems -- including the New England Power Pool, the Puerto Rico Electric Power Authority, the state of Maharashtra (India), and numerous individual U.S. utilities -- to examine the cost and reliability implications of alternative resource choices and planning assumptions. I have conducted solicitations for electric energy and capacity transactions, and have managed the power supply of the Vermont Electric Cooperative, Inc. since 1991. I have provided expert testimony regarding electric utility planning issues, avoided costs, and power costs in the context of rate cases. A copy of my resume is attached as Exhibit DCS-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the evidence that Pennsylvania Power and Light ("PP&L") has presented regarding the future market price of electricity in the PJM market. Specifically, my testimony will address the testimony and market price analysis presented by PP&L witness Dr. Scott Jones. My testimony will:

- Review the methodologies and input assumptions used to develop PP&L's estimate of market electricity prices;
- Present an alternative analysis of market electricity prices for the PJM area, based on a detailed simulation of the PJM system, providing an internally consistent basis for evaluating the generation market revenue of PJM utilities.

Q. PLEASE SUMMARIZE YOUR MAJOR FINDINGS.

A. My primary findings are as follows:

- The PP&L market price analysis conducted by Dr. Jones--which is used by Mr. Schadt to develop the Company's stranded generation costs--relies on a flawed methodology which tends to understate the future price of electricity, and therefore the future revenues associated with PP&L's generating sources. To the extent that actual PJM market prices and PP&L generation revenues turn out to exceed the Company's forecasts for this reason, PP&L will obtain a windfall at ratepayers' expense.
- Some PP&L generating units will obtain additional revenue from ancillary services; these revenues are not reflected in PP&L's market price analyses.
- Dr. Jones assumes general price inflation of 2.5 percent per year throughout the planning horizon, and declining prices (in real terms) for oil, natural gas, and coal. Together, these assumptions yield much lower fossil fuel prices for PJM generating units than PECO Energy ("PECO") recently utilized to project PJM market prices

- and its stranded costs. As a result, the projected long term generation market prices projected by PP&L are much lower than those projected by PECO.
- I have conducted an alternative generation market analysis, based on publicly available generation, load, and fuel price data. My analysis reflects fuel price escalation rates from the October 1996 *DRI World Energy Service U.S. Outlook*, the rates used by two of PECO Energy's three market price witnesses. Given my methodology and input assumptions, my analysis more accurately reflects market conditions expected in PJM and thus provides a more appropriate basis upon which to estimate PP&L's stranded generation costs. I project significantly higher long term market prices than does Dr. Jones, indicating significantly greater value for PP&L's generating resources.
- Actual market electricity prices will, of course, differ from today's projections. The Commission should keep in mind the uncertainty of potential market price outcomes when evaluating the magnitude of PP&L's stranded cost and when determining the amount of stranded costs that PP&L should be allowed to recover through a CTC. PP&L's market price analysis does not explore the impact of alternative market price scenarios on the value of its generating assets, nor has it tested the likely symmetry of risk between ratepayers and the Company regarding the potential alternative outcomes.

<u>Critique of PP&L's Market Energy Price Methodology</u>

Q. PLEASE EXPLAIN HOW PP&L REPRESENTS THE GENERATION MARKET.

A. Dr. Jones represents the generation market in terms of two primary components: capacity and energy. The energy market reflects an hourly interaction between supply (all the available generating units in PJM) and demand, in which each generator selected to operate in the hour behaves as a "price taker", receiving a market price for the energy it produces. Dr. Jones states ". . . the fuel and variable O&M of the least efficient producer in any hour will set the market clearing price in that hour. . . . (Statement 7, page 10)" Dr. Jones simulates the interaction of the energy market using the EGEAS production costing model.

The capacity market represents payments to generators made in exchange for the right to call on the generators' electric output. In PJM, such capacity transactions are made in part to meet capacity requirements assigned to load serving entities. The realized capacity price depends on the state of supply (surplus or deficit)with respect to demand (capacity requirement). Dr. Jones states that "In order for companies to commit capital for new generation equipment, the expected competitive market price (combined energy and capacity prices) must be high enough to offer a return on capital as well as cover incremental operating costs. (Statement 7, page 12)"

Q. PLEASE SUMMARIZE YOUR FIRST CONCERN WITH THE METHODOLOGY THE COMPANY USED TO DEVELOP ITS ESTIMATE OF THE ENERGY CLEARING PRICE IN PJM.

A. The energy market clearing price is an important component of the stranded cost analysis, because, as noted above, in the restructured PJM energy market, all generators selected to operate in PJM in a given hour will receive the market clearing price for that hour. Dr. Jones states that ". . . the hourly market clearing price will reflect the variable cost of the last unit dispatched. . ." in the market (Response OCA-III-45, included as Exhibit DCS-2). Dr. Jones bases his estimate of the market clearing price on the *incremental cost* (the cost to change output) of the market's marginal generating unit(s) in each hour, rather than on those units' *average variable costs in each hour*.

The marginal generating units in PJM are typically coal, oil, or gas fired units with a declining incremental heat rate curve. That is, production at low ("part load") output levels is typically less efficient (more costly) than product at maximum output ("full load"). As output levels increase, the incremental rate of fuel input required per incremental kWh output is less (in some cases, much less) than the average rate of fuel input required to produce that output level. Hence, if the energy market clearing price is based on the incremental heatrate of the marginal generating units in the market, that price will be systematically lower than the actual variable costs incurred by those marginal units (and potentially many other units with similar variable costs). Energy bids priced on this basis would therefore often be inadequate to recover the actual variable costs of the marginal generators.

In Response OCA-III-45 (see Exhibit DCS-2), Dr. Jones recognized this outcome, and suggested that generators would bid their output in blocks that reflect their more costly part load operation. His market price analysis, however, makes no such adjustment.

Q. IS IT REASONABLE TO EXPECT THAT SUPPLIERS IN A COMPETITIVE MARKET WILL BE WILLING TO OPERATE DURING HOURS IN WHICH THE MARKET PRICE UNDERSTATES THEIR VARIABLE OPERATING COSTS?

A. No, it is not. I therefore believe that Dr. Jones' method systematically understates the market clearing price.

Since the incremental variable costs of many generating units are lower than their average variable costs, the highest-cost generating units dispatched in each hour may fail to recover their variable costs of operation through the market energy price. In Docket R-00973877, PECO market price witness Dr. William Hieronymus recognized this problem of "negative cost recovery" and stated that he expects the problem will be resolved either through pool rules or through generating unit owners *increasing their bid prices* so as to cover their average variable operating costs. In his market price analysis, Dr. Hieronymus chose to address the issue of negative cost recovery by identifying each instance in which a generating unit failed to recover its actual variable operating costs through the energy market price, and assigned a specific uplift payment to each such unit. While I do not support Dr. Hieronymus' exclusion of uplift charges from the market energy price, and I believe that his calculated uplift charges may be too low, they would at least compensate marginal PJM generators for some hours in the analysis when their energy bids are not fully recovered through the energy market price.

I was not able to determine whether or not Dr. Jones, in his PP&L market price analysis, incorporated uplift payments to address projected instances of negative cost recovery. Dr. Jones' Exhibit STJ-7 and STJ-8 (which summarize his market energy and capacity price results) do not appear to reflect any uplift payments. Similarly, the stranded cost calculations associated with each of PP&L's generating units provided by Mr. Schadt do not appear to include a generating unit revenue item corresponding to uplift payments. It therefore appears that Dr. Jones has estimated energy market clearing prices utilizing incremental generating unit heatrates, but has made no adjustment to unit revenues to account for not-recovered variable costs. If this is the case, then Dr. Jones' projection of total PP&L generation revenues (including revenue sources other than the market energy price) is understated.

Q. WHY ELSE WOULD IT BE INAPPROPRIATE TO ESTIMATE THE ENERGY MARKET PRICE BASED ON THE COMPANY'S METHOD?

A. As discussed above, defining the energy market clearing price in terms of only the incremental costs of the market's marginal unit(s) would cause the energy market price to systematically understate the market's actual decremental cost[1] of energy production. An understated energy market clearing price would send an incorrect (low) price signal that fails to encourage the efficient utilization and allocation of generating resources so as to minimize the system's energy costs.

Q. GIVEN THE METHOD THAT PP&L HAS USED TO PROJECT FUTURE MARKET

[1] Incremental/decremental costs represent the estimated increase/decrease in production costs that would result from a discrete action (e.g. starting or shutting down a particular generating unit, or making a firm energy purchase), and include the effects of generating unit startup costs and part load operation. Utilities and power pools base their unit commitment and dispatch decisions on analyses of incremental and decremental costs, not simply the marginal cost to serve an additional kWh of load.

ENERGY PRICES, WOULD IT BE INAPPROPRIATE TO UTILIZE "UPLIFT PAYMENTS"?

A. No, not necessarily. For the reasons outlined above, the estimated energy market price should reflect the total variable costs of generating units, rather than the incremental cost of increasing part-load output.

If generating units are selected to operate out of economic order, it may be appropriate to pay uplift to those generating units rather than skew the energy market price. For example, if, during off-peak hours, a generating unit is dispatched out of economic order to ensure that its output will be available during peak hours, it would be appropriate and economically efficient to cover the generator's shortfall in variable costs through an uplift payment, rather than raise the market clearing price. In this instance, the system operator is incurring "additional" costs during some hours in order to obtain greater savings in other hours, minimizing the market's total cost of energy. Similarly, the most cost-effective way to maintain spinning reserve during some hours could be to operate one or more generating units out of economic order. In such circumstances the highest-cost unit operating may not approximate the market's marginal value of energy, and might appropriately be excluded from the calculation of the energy market clearing price.

Q. PLEASE EXPLAIN HOW THE COMPANY'S MARKET PRICE ANALYSIS ADDRESSES START-UP COSTS.

A. Start-up costs are the costs associated with the fuel, labor and operating procedures required for startup. Dr. Jones' analysis does not include start-up costs in either his projection of market energy price or his projection of operating costs for PP&L generating units. While Dr. Jones is correct that start-up costs constitute a small portion of the operating costs of most generating units, and that the inclusion of start-up costs in the market energy price would be somewhat offset by start-up costs incurred by PP&L's generating units, these are legitimate, unavoidable operating costs for thermal generating units that I believe should be included in the analysis if possible. Because some PP&L

generating units (i.e. nuclear and hydro) do not incur startup costs, or start infrequently, the net effect of including start-up costs would be to increase the collective value of PP&L's generation.

Q. GIVEN YOUR DISCUSSION OF INCREMENTAL HEATRATES, UPLIFT CHARGES, AND STARTUP COSTS, HOW SHOULD BIDDERS IN THE PJM ENERGY MARKET BE REPRESENTED?

A. For the purpose of forecasting PJM energy market prices, it is appropriate to represent the energy bid of each thermal generating unit based on the unit's "as-operated" average heatrate, thereby reflecting the unit's actual operating condition and costs.

For units that are operated strictly at full load, the "as operated" heatrate will tend to approximate the unit's full load average heatrate. For units that are operated regularly at less efficient partial output levels, the as-operated heatrate will tend to exceed the full load average heatrate. The as-operated heatrate reflects the realistic efficiencies incurred by thermal generating units during operation (including low load and cycling conditions), and includes the fuel consumed during startups.

Q. DOES PP&L'S ANALYSIS IN THIS CASE REFLECT ALL LIKELY SOURCES OF REVENUE FOR THE COMPANY'S GENERATING UNITS?

A. No, Dr. Jones does not. Although Dr. Jones models a spinning reserve requirement for PJM, he does not attempt to determine the revenues that generators providing spinning reserve in a given hour would receive. Dr. Jones does not model any other ancillary services.

<u>Critique of PP&L Input Assumptions</u>

Q. HOW DO FUEL PRICE ASSUMPTIONS AFFECT PP&L'S ESTIMATES OF GENERATION MARKET PRICES AND STRANDED GENERATION COSTS?

A. PP&L owns numerous generating units, which burn a range of fuels. As a result, the

Company's future operating costs will depend in part on the delivered cost of those fuels, which include coal, natural gas, residual fuel oil, distillate oil, and uranium. Specifically, PP&L generates the majority of its electricity with nuclear and coal-fired units; oil and natural gas play a limited role.

The energy market prices that PP&L will receive for the output of its generating units will depend significantly on fuel prices faced by the "marginal" generating units in the PJM electricity market--those units that tend to operate during high demand periods, but not on an around-the-clock basis. In PJM, the margin is defined primarily by coal, oil, and gas-fired sources. Nuclear and hydroelectric sources will rarely (if ever) define the market price.

Because PP&L's fuel mix (and those of most Pennsylvania utilities) differs significantly from the fuel mix that will define PJM energy market prices, changes in fossil fuel prices will impact PP&L's generation market revenues more than its generation costs. PP&L's nuclear, coal, and hydro units are rarely, if ever, at the margin. Energy clearing prices are most often set by more expensive coal, oil and gas units elsewhere in PJM. If gas and oil prices increase, the energy revenues realized by PP&L could be much greater than expected, substantially lowering the Company's actual stranded generation costs.

Q. WHAT APPROACH DID PP&L USE TO DERIVE ITS BASE FUEL PRICE ASSUMPTIONS FOR GENERATING UNITS IN THE PJM MARKET?

A. In Response OCA-III-64, PP&L provided (under protection of a confidentiality agreement) Dr. Jones' base year (1996) fuel price and variable O&M cost assumptions for each generating unit in PJM. In Responses OCA-III-67 and OCA-III-68 (attached as Exhibit DCS-3), Dr. Jones referred back to his base fuel price values but declined to explain how they were derived. Dr. Jones' 1996 base fuel price assumptions for existing coal and oil-fired units appear to be, on the whole, somewhat lower than the units' actual 1996 fuel prices as reported in the FERC Form 1

For future gas-fired combined cycle units, which affect projected future market prices in the PJM region, Dr. Jones assumed a 1996 fuel price that is 10 to 15 percent lower than the actual 1996 fuel prices incurred at most gas-fired generators in PJM as reported in the FERC Form 1, and is lower than the gas prices assumed by PECO for new combined cycle generating units in Docket R-00973877.

Q. HOW DID DR. JONES PROJECT FUTURE FUEL PRICES FOR GENERATING UNITS IN THE PJM MARKET?

A. Dr. Jones reviewed several fuel price forecasts, and used his judgment to select price escalation rates for each major fuel type. Dr. Jones describes the resulting outlook for delivered prices of oil, natural gas, and coal as a reasonable "consensus forecast." Similarly, Dr. Jones used judgment and a review of historical data to arrive at a 2.5 percent annual inflation rate for the study period.

Specifically, taking inflation into account, Dr. Jones assumes that oil and gas prices will remain constant through 1999 and will increase at 2.5 percent per year thereafter, for a decline of about 7 percent in real terms by 2015. Dr. Jones assumes that coal prices will increase at 1.5 percent per year through 2000 and at 1.7 percent per year thereafter, for a decline of about 14.5 percent in real terms by 2015.

Q. HOW DO DR. JONES' INFLATION AND FUEL PRICE ASSUMPTIONS COMPARE TO THOSE USED BY PECO TO PROJECT FUTURE MARKET PRICES?

A. Dr. Jones assumes lower inflation, as well as lower fossil fuel price escalation in real terms, than either of the two escalation forecasts utilized by PECO in its recent restructuring filing. Exhibit DCS-4 (3 pages) compares Dr. Jones' fuel price escalation rates for natural gas, coal, and residual oil to the DRI escalation rates utilized by two of PECO's market price witnesses. The exhibit also compares the price escalation rates for each fuel to the general inflation rates assumed by DRI and Dr. Jones. The cumulative escalations for each fuel and for general inflation are expressed relative to a 1996 base value of 1.0. Exhibit DCS-4 illustrates that over the planning horizon, Dr. Jones' cumulative escalations for oil and gas prices are lower than his assumed rate of general inflation, significantly lower than DRI's projected rate of general inflation, and much lower than DRI's projection of price escalation.

Q. PLEASE SUMMARIZE HOW VARIABLE O&M COSTS FOR EXISTING GENERATING UNITS ARE REPRESENTED IN THE COMPANY'S MARKET PRICE ANALYSES.

A. Dr. Jones has represented the energy bids of existing PJM generating units as the sum of fuel costs and variable O&M costs. I believe that this is an appropriate approach to use in the analysis of PJM energy market prices, although (as discussed above) I disagree with Dr. Jones' use of part load heatrates to define the energy market price.

The variable O&M assumptions in Dr. Jones' analysis vary considerably by fuel type, and by generating unit. On average, Dr. Jones' variable O&M values are noticeably higher than those assumed by PECO in Docket R-00973877 for the same units. PECO, however, included additional emission "adders" in the dispatch price of generating units, to reflect the cost of allowances or compliance measures for SO_2 and NO_x emissions.

Dr. Jones did not model NO_x allowances, and I was not able to determine whether the PP&L variable O&M costs provided in Response OCA-III-64 reflect only direct operation and maintenance costs, or if they also include an SO_2 adder. To the extent that PP&L's variable O&M assumptions reflect only direct variable O&M costs, Dr. Jones' forecast of market prices (described below) may be understated.

Q. HOW HAS THE COMPANY REPRESENTED THE COSTS OF EMISSION COMPLIANCE IN ITS MARKET PRICE ANALYSIS?

A. For generating units that emit SO_2, Dr. Jones has included in the dispatch price an adder to reflect the cost of emission allowances. As noted in the previous response, I have not determined whether the variable O&M costs provided in Response OCA-III-64 include these adders, or whether they are additive. Dr. Jones' assumed SO_2 allowance prices in the near term are similar to those assumed by PECO. In the long term, PECO assumes that SO_2 allowance prices will escalate significantly in real terms; Dr. Jones assumes a much lower long term price trend.

In addition to purchasing allowances, PP&L has stated that its emission compliance plans include some fuel switching to lower sulfur coal, which is more costly. I do not know whether Dr. Jones' analysis assumes any fuel switching for coal-fired units owned by PP&L or other PJM members.

New Generating Capacity

Q. WHAT GENERATING CAPACITY OPTIONS DOES PP&L ASSUME WILL BE AVAILABLE IN PJM TO MEET DEMAND GROWTH AND ATTRITION OF EXISTING GENERATING UNITS?

A. Dr. Jones assumes two primary options for new electric generating capacity in PJM. For peaking duty, simple cycle combustion turbine ("CT") units were assumed to be available for construction when needed. For baseload and cycling duty, Dr. Jones assumed that large scale combined cycle combustion turbine ("CC") plants burning natural gas would be available. Based on current planning assumptions, these two options represent the most cost-effective generation options for their respective operating roles.

Q. WHAT GENERAL ASSUMPTIONS DOES PP&L MAKE FOR THESE OPTIONS?

A. There have been substantial improvements in the CT and CC technologies in recent years, resulting in substantial thermal efficiency improvements. Dr. Jones assumes heat rates for new capacity options consistent with relatively advanced equipment, although his assumptions are not quite as optimistic as those made by PECO's market price witnesses

In addition, the capital cost of CT and CC plant equipment has declined significantly in recent years, due in part to these same technological improvements (i.e. increasing the output of particular units). This price decline appears to also reflect increased competition among suppliers of combustion turbines and ancillary equipment

Q. PLEASE COMMENT ON THE SPECIFIC CAPITAL COSTS THAT PP&L HAS ASSUMED FOR THE CC AND CT OPTIONS.

A. Dr. Jones assumes a capital cost of $595/kW for the CC option, and $338/kW for the CT option, based on consultation with PP&L personnel. Detailed support was not provided.

I believe that Dr. Jones' capital costs for newly constructed generating capacity are reasonable. In my analysis of PJM market prices, I have assumed slightly more optimistic (lower) capital costs: $550/kW ($1996) for the CC option, and $290/kW ($1996) for the CT option. I developed these values based on a review of the detailed assumptions that PECO provided in support of its capital cost assumptions. I expect that some new units will incur higher costs, due to one or more of the following factors:

- Greater interest costs during construction;
- Increase in CC/CT equipment costs from current market conditions, which represent a historical low point;
- Greater land costs (my figures reflect a generic land price from the Electric Power Research Institute's "Technical Assessment Guide");
- Greater project development costs, representing the "soft costs" needed for the legal, financing, and permitting efforts needed to develop a successful project;
- Non-standardized plant features, reflecting tradeoffs between plant design and capital cost. For example, combined cycle units with the most complex and efficient steam cycles will tend to cost more, as will units with reliability features such as a bypass stack or multiple shaft design. The 1996 Gas Turbine World Handbook, which provides the basis for the equipment cost estimates of PECO witness William Hieronymus, states: "These turnkey plant price levels, as noted,

are for 'plain vanilla' plant equipment and services. Extended site work such as cogeneration process steam or utility plant tie-ins are not covered, nor are extensive buildings, nor a large inventory of operational spares such as combustor baskets, blades and vanes, etc." I have assumed quite competitive reliability (annual availabilities on the order of 90 percent) and thermal efficiencies (as-operated heatrate of 6,700 BTU/kWh) for new CC units, making it unlikely that their designs will be the cheapest;

- Selective catalytic reduction ("SCR") equipment for control of NOx emissions on CC units. The turnkey equipment costs underlying my estimate include dry low-NOx burners, but not equipment for catalytic reduction of NOx or CO_2 emissions. To the extent that SCR or other control measures are actually required for some or all of the new CC generating units built in PJM, additional capital and operating costs would be required;
- General plant. My cost estimates treat the CC and CT options as stand-alone facilities, and do not include an allocation of general plant which would presumably be incurred by generating companies in the PJM market.

Any or all of these factors could increase the cost of new capacity (and therefore market prices) relative to my analysis. I chose somewhat optimistic capital cost assumptions to reflect the fact that: (1) other new units at the most preferable sites (e.g. sites with close proximity to fuel and electrical interconnections) may be able to reduce their infrastructure costs somewhat compared to a "greenfield" site; and (2) there may be some additional improvement in the CT and CC technologies over the planning horizon.

Q. HOW DID DR. JONES DEVELOP HIS FORECAST OF MARKET CAPACITY PRICES?

A. Dr. Jones based his capacity price forecast on data provided him by PP&L, along with his knowledge and understanding of the market. Dr. Jones declined, however, to provide the requested details of the analysis he used to derive market capacity prices. Specifically, in response to an interrogatory dated May 22, 1997 from the Office of Small Business Advocate requesting that information, Dr. Jones claimed that all work papers detailing his analysis were confidential and protected by attorney client privilege. This response is included as Exhibit DCS-5.

Q. WHEN DOES DR. JONES ASSUME THAT NEW GENERATING CAPACITY WILL BE INTRODUCED INTO THE PJM MARKET?

A. In response to Set 1, Question 24a dated May 22, 1997 from the Office of Small Business Advocate, Dr. Jones states that he expects a capacity deficit in PJM by the year 2002. However, in Response OCA-III-88 (the data of which has been classified as confidential), Dr. Jones shows the introduction of significant new generating capacity before 2002. The addition of this capacity would appear to be inconsistent with an assumed capacity deficit in 2002, and with the market capacity prices that Dr. Jones has projected. In my own analysis, and in analyses submitted by PECO in Docket R-00973877, a capacity deficit is assumed to develop in 2001.

Q. DOES THE CAPACITY PRICE ASSUMED BY DR. JONES SUPPORT THE INTRODUCTION OF NEW CT CAPACITY AT THE TIME HE HAS ASSUMED?

A. No, it does not. Dr. Jones assumes that the capital cost of a new combustion turbine is $338/kW. Based on a reasonable carrying charge rate (to reflect recovery of and return on the capital investment), the annual carrying charges associated with this new combustion turbine would be higher than Dr. Jones' estimated market capacity price when he assumes the addition.

Although requested in Question OCA-III-74, Dr. Jones did not provide the carrying charge rate assumed for new capacity in his analysis, nor does his testimony indicate in which year's dollars his capital cost figures are stated. I was therefore unable to determine Dr. Jones' precise assumption regarding the carrying costs for the new CT on a per kW-yr basis. However, using the 12.75 percent real-levelized carrying charge rate and $290/kW ($1996) CT capital cost assumed in my analysis, the carrying charge for a new CT would be more than twice the capacity price Dr. Jones assumed. This issue is temporary, as Dr. Jones estimates that the market price of capacity will increase substantially by 2002.

Q. WHAT IS THE POTENTIAL IMPACT OF INTRODUCING NEW CT UNITS INTO THE GENERATION MIX BEFORE THEY ARE COST JUSTIFIED?

A. If a developer were to construct a new CT in the time frame and with the capital costs and other characteristics assumed by Dr. Jones, it would lose money in the first two years. A developer does not generally invest to lose money, so Dr. Jones' assumption that new capacity will be built in the time frame he assumes appears questionable. Because the new generating units are less costly to operate than some existing units in PJM, the introduction of new capacity would tend to depress Dr. Jones' energy market clearing price. It is not clear whether the assumed introduction of new CTs in the time frame assumed by Dr. Jones has also suppressed Dr. Jones' projection of market capacity prices.

Q. HAVE YOU REVIEWED PP&L'S ASSUMPTIONS REGARDING FIXED O&M COSTS FOR FUTURE PJM GENERATING UNITS?

A. Yes, I have. By fixed O&M, I refer to all non-fuel expenses associated with operating and maintaining a generating facility. For new CC units, Dr. Jones assumes an annual fixed O&M charge of $5.28/kW-year (in $1996). I am concerned that this cost level may not be sufficient to cover significant fixed costs such as property taxes and insurance (to the extent they are not included in the carrying charge rate), or the periodic capital additions that will be required to maintain the combined cycle facility's availability and performance at assumed levels.

For newly constructed CC and CT units, a regimen of equipment maintenance and refurbishment will be needed to maintain the equipment's thermal efficiency and output at original levels. Whether classified as fixed O&M costs or capital additions, the costs of these efforts are likely to make up a significant portion of a CC unit's non-fuel operating costs. In addition, there is not an extensive record of industry experience with the advanced equipment that PP&L assumes will provide PJM's CC capacity option, and it appears quite optimistic to assume going-forward fixed O&M costs as low as projected by Dr. Jones without assuming significant additional capital expenditures. In my analysis of PJM market prices, I have therefore assumed fixed costs (including O&M and capital additions) of $17/kW-year for a new CC unit.

Q. HOW DOES PP&L'S ANALYSIS OF STRANDED GENERATION COSTS REPRESENT ADMINISTRATIVE AND GENERAL COSTS?

A. Administrative and general ("A&G") costs for an electric utility include required salaries and costs not assigned to specific generation, distribution, or production functions. As reported on the FERC Form 1, major categories of A&G costs include employee pensions and benefits, property insurance, office supplies and expenses, regulatory commission expenses, and administrative and general salaries.

In estimating stranded generation costs in this case, PP&L included in the going-forward costs of its existing generating units the full allocation of A&G costs to production. In contrast, Dr. Jones' analysis of generation market prices does not appear to include any A&G costs for the future generating units he assumes will be constructed in the PJM market.

In the context of market price analysis, it is appropriate to reflect A&G costs in a consistent manner, assigning appropriate A&G costs to both PP&L generating units and new market entrants. For the purpose of this analysis, I have assumed that A&G costs associated with plant operations will add 10 percent to the projected fixed O&M costs for a new CC unit. The effect of this assumption is to add about $2/kW-year to the unit's annual non-fuel costs.

Q. WHEN WILL PJM NEED ADDITIONAL GENERATING CAPACITY, AND WHAT WILL BE THE EFFECT ON MARKET CAPACITY PRICES?

A. An analysis of PJM supply sources and projected demands indicates that the PJM Interconnection will maintain a modest surplus of installed generating capacity in 1999, reach equilibrium in 2000 and require additional capacity thereafter. This analysis reflects an assumed capacity reserve requirement of 18 percent, which is somewhat optimistic and may not be achieved by 2000. I expect that the market capacity price will approximate the carrying cost of new peaking capacity by 2001. Even if actual supply and demand conditions turn out differently than I have assumed, several factors make it doubtful that prices will reflect a surplus condition (and discounted capacity prices) for any significant period.

First, even if supply and demand conditions evolve more favorably, upward pressure on capacity prices will exist before PJM's installed capacity surplus reaches zero. As the surplus declines, uncertainties in loads and resources will make producers increasingly reluctant to sell their limited excess capacity.

Second, neighboring interconnected regions may be able to sell into PJM, but may also seek to purchase capacity. In particular, the New England Power Pool expects to have a substantial need for installed capacity and associated energy during the next 6 to 18 months, due primarily to the retirement of the Connecticut Yankee unit (560 MW), and to the continued unavailability of four units on the Nuclear Regulatory Commission's Watch List: Maine Yankee (870 MW) and Millstone Units 1, 2 and 3 (over 2,600 MW). Maine Yankee's owners recently stated their intention to reduce ongoing expenditures, consistent with a "protect and preserve" posture, and to consider closing the unit for economic reasons if a buyer cannot be found in the near future. To the extent that these or other major generating units in the Northeast and Mid-Atlantic remain unavailable, upward pressure will be exerted on energy and capacity prices.

Finally, the capacity market will be affected not only by the amount of installed capacity, but also by the economic competitiveness of that capacity. Because revenues will not be guaranteed in a competitive generation market, the owner of a generating unit with relatively high going-forward costs may choose to close the unit for economic reasons, even if the unit is still physically operable. I did not test the economic viability of the existing generating units in PJM. To the extent that some "economic retirements" actually occur, there will be additional upward pressure on capacity and energy prices relative to my analysis, and to the market price analyses of PP&L and PECO.

Independent Market Price Analysis

Q. WHY DID YOU CONDUCT AN INDEPENDENT ANALYSIS OF THE PJM GENERATION MARKET, RATHER THAN RELYING ON THE ANALYSES PP&L HAS PRESENTED IN THIS CASE?

A. First and perhaps most important, conducting an independent analysis provides the Commission with a practical mechanism to assess the stranded costs and restructuring plan on a common basis.

In addition, it has been difficult to verify some of the assumptions and methods of the market price analyses sponsored by PP&L, due in part to the sheer volume of information. While useful information can be obtained by requesting the Company to perform alternative analyses (as OCA did in Request OCA-VIII-1), it would be impractical to develop an alternative case in this manner.

Finally, my analysis is intended to assist the Commission by providing a balanced, non-utility perspective on generation market issues. My general approach in developing assumptions and methods used in the analysis was not, however, to develop a high bound or "counter" to the Company's analysis. As shown in my discussion of the costs and carrying charges associated with new generating units, I have sought a reasonable expected value outcome on each issue. I believe that I have chosen assumptions that have equivalent likelihood of being above or below the actual outcome.

Q. PLEASE SUMMARIZE THE METHODOLOGY UPON WHICH YOUR MARKET PRICE ANALYSIS IS BASED.

A. My analysis assumes the same basic market structure as Dr. Jones' analysis. The vast majority of market revenues are associated with two market components: an hourly market for electric energy, which will reflect the interaction of hourly supply and demand, and a market for installed generating capacity, reflecting the relative scarcity of capacity in the PJM region.

To approximate the PJM energy market, I conducted a dispatch analysis of the PJM system using the ENPRO dispatch simulation model. ENPRO is a detailed, chronologic model well suited to represent a large electric system like PJM. The model is used by utilities and others for a range of operational and planning analyses. ENPRO represents unplanned (or "forced") outages of generating capacity randomly, on a daily basis. ENPRO was used to represent the PJM Interconnection as a whole, and does not distinguish potential market price differences due to transmission constraints within PJM. Imports are represented explicitly as available sources to be dispatched when economic.

The most important methodological difference between my analysis and Dr. Jones' PP&L analysis is in the derivation of the energy clearing price. I have represented the energy market in terms of bids for delivered energy from each PJM generating unit, in which the energy market price is defined by the highest selected bidder, and each bidder is assumed to bid based on its **total variable cost.** My approach contrasts with the approach utilized by Dr. Jones, who assumes that the market energy price at any time will reflect the **incremental variable cost** of the marginal PJM generating unit(s).

Like Dr. Jones' analysis, my analysis reflects the assumption that over time, the market price for capacity will approximate the carrying costs of the CT option, the least costly type of additional generating capacity.

Q. PLEASE SUMMARIZE THE PRIMARY INPUT ASSUMPTIONS UTILIZED IN YOUR PJM MARKET ANALYSIS.

A. The fundamental input assumptions (or groups of assumptions) in my analysis are generally based on publicly available data, or on assumptions described in my testimony: The primary assumptions are as follows:

- PJM generating units and their maximum capacities were identified from EIA Form 860;
- Actual annual fuel prices for PJM generating units were obtained on a station basis for calendar year 1996, from the FERC Form 1. From 1997 forward, fuel prices were escalated according to major fuel type (i.e. coal, or residual oil), based on escalation rates from the Fall 1996/Winter 1997 DRI price forecast; the annual escalation values are presented in Exhibit DCS-6;
- Variable O&M costs of PJM generating units: based on assumptions presented by PECO in Docket R-00973877. These values, which include only direct O&M costs and not emission adders, are in general lower than those utilized by Dr. Jones;
- Heatrates: the energy bid of each thermal generating unit is represented based on its average as-operated heatrate for 1996, as obtained from FERC Form 1. This is the bid which will, over a generating unit's dispatch cycle, approximate the unit's total actual fuel costs;
- Generating unit availabilities: developed for major classes of generating units, based on NERC records of 1990-1994 actual generating unit availabilities, with the following exceptions: (1) Output of PJM hydro units was based on the estimated long term average output; (2) Nuclear generating units in PJM are assumed to produce at a 75 percent annual capacity factor in each year of the analysis; and (3) non-utility generating capacity was projected in accordance with the North

American Electric Reliability Council's 1996 Electric Supply and Demand Database.

- Projected peak load and energy requirements for PJM were based on data obtained from MAAC Form EIA-411.

Q. YOU NOTED THAT YOU USED PUBLICLY AVAILABLE INFORMATION WHERE POSSIBLE FOR YOUR ANALYSIS. IS THE DRI FORECAST THAT YOU UTILIZED PUBLICLY AVAILABLE?

A. No. I obtained the escalation rates associated with PECO's analysis in discovery. I used them for my analysis because DRI is a well-known forecasting firm that has been used in numerous electric industry analyses, and because the future described by the DRI escalation rates is reasonable. Specifically, coal prices are assumed to decline steadily in real terms over 20 years. Oil and gas prices are assumed to initially decline by about 10 percent in real terms, and to increase moderately thereafter. Over 20 years, oil and gas prices are assumed to increase by between 15 and 20 percent in real terms. Uranium prices were assumed to remain constant over the planning horizon in real terms.

<u>Market Price Results</u>

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR MARKET PRICE ANALYSIS.

A. Exhibit DCS-7 and DCS-8 summarize the results. Exhibit DCS-7 presents the projected annual average market energy price, annual market capacity price, and total market price (including energy and capacity) from 1999 to 2015. These values represent the unweighted average of market prices for all hours of the year, and would represent the realized wholesale market revenue of a generating source producing at maximum capacity during all hours of the year.

Exhibit DCS-8 presents the average annual energy, capacity, and total market revenues projected to be achieved by PP&L's generating units in each year of the analysis. Because some of PP&L's generating units are load-following, and tend to produce during higher-cost peak hours, the achieved market prices in Exhibit DCS-8 are somewhat higher than the unweighted averages in Exhibit DCS-7.

Exhibit DCS-9 compares the projected all-hours (baseload) market prices in my analysis to those projected by Dr. Jones, as well as those projected by PECO's three market price witnesses. In short, the results of my analysis show significantly higher market energy prices than those projected by Dr. Jones. This appears to be due partly to the methodological differences in how the market energy price is calculated, and partly to the difference in our fuel price and inflation assumptions.

Q. PLEASE DESCRIBE THE CONSTRAINTS ON YOUR MARKET ANALYSIS.

A. My energy market analysis is conservative (i.e. tends to understate market prices) in at least two ways. First, my analysis does not reflect the inflationary effect of emission allowance prices on the energy market. PECO and PP&L chose to represent the effect of emission constraints on the PJM market energy price by including emission "adders" (in dollars per Mwh) to the dispatch price of each emitting generating unit. While I have not examined in detail the derivation of specific adders, this approach appears reasonable.

I did not, however, have sufficient information to similarly represent the effects of SO_2 and NOx constraints on the dispatch prices of all PJM generating units in my analysis. I therefore simulated the operation of the PJM energy market based solely on the direct fuel costs and estimated variable O&M costs of PJM generating units. Had I been able to include the effects of SO_2 and NOx emission adders in the energy market analysis, the resulting energy market prices would have been higher in many hours of the year. Because a substantial fraction of PP&L's generation (i.e. nuclear and hydro) incurs no allowance costs, the inclusion of allowances in the analysis would increase PP&L's net generation revenues. The effect of including NOx adders in the market price analysis would be to increase costs and revenues for generating units that require the adders, and to increase revenues for units that do not require the adders. Based on the adders that

PECO presented for its generating units in Docket R-00973877, I estimate that the net effect of including NOx adders in the PJM market price analysis would be to increase market generation prices by less than $1/MWh on average. Even an increase of $0.5/MWh, however, would raise PP&L's net revenues significantly.

Second, the commitment and dispatch of PJM generating units in my analysis does not reflect spinning reserve requirements, which tends to require commitment of additional, more costly generating units.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The generation market price analysis upon which the Company's estimate of stranded generation costs relies is methodologically flawed, and systematically understates the likely energy prices in the PJM market. My alternative analysis, which is based on publicly available generation and load data (including average generating unit heatrates), provides a practical way for the Commission to implement consistent market price assumptions in its determination of stranded generation costs. My analysis yields generation market prices that are significantly higher than the PP&L analysis developed by Dr. Jones.

It is important to note that while my projected market prices are higher than those sponsored by PP&L, my analysis does not represent a high bound on market prices. A host of factors -- including environmental compliance costs, higher fossil fuel costs, poor performance of existing generating units, and higher carrying charge rates for new generation -- could significantly increase generation market prices (and therefore PP&L's net generation revenue). Similarly, the differing future fuel price escalations presented by DRI and Dr. Jones fall within a larger range of potential outcomes.

Q. Does this conclude your testimony?

A. Yes.

42797

Douglas C. Smith

LA CAPRA ASSOCIATES
Senior Analyst

Mr. Smith is a Senior Associate with La Capra Associates with over ten (10) years of experience in utility economics and planning. As Electrical Planning Engineer and Power Cost Analyst for the Vermont Department of Public Service, Mr. Smith specialized in electric utility power costs, resource planning, and modeling issues. Since joining La Capra Associates in 1991, Mr. Smith has assisted a range of clients in the areas of resource planning, operational issues, and market transactions.

Mr. Smith's professional accomplishments include:

Market Price/Transaction Analysis

On behalf of the New Hampshire Public Utilities Commission, played a central role in the projection of New England power prices in a restructured electricity market, for use in the determination of stranded cost charges for New Hampshire utilities.

On behalf of the World Bank, assisted in the review of pricing and policy issues related to the acquisition of non-utility power in India. On behalf of utilities and regulatory agencies, performed comprehensive evaluations of proposed wholesale electric power transactions, including domestic and international transactions of up to 20 years in duration.

Competitive Power Solicitation and Management

Manages and conducts all power transactions of the Vermont Electric Cooperative, Inc. Responsibilities include initial analyses of need, negotiation with potential trading partners, and development of contract terms. Responsible for familiarity with the New England Power Pool's requirements regarding energy, capacity, and ancillary services (a significant factor for the Cooperative), and ensuring that they are met in the least costly manner possible.

Conducted formal solicitations for long term and short term electricity transactions. Played a primary role in the solicitation, evaluation, and negotiation of long term power supply agreements for the Nantucket Electric Company and the Vermont Electric Generation & Transmission Cooperative, Inc.

Electric Utility System Operation

Performed detailed, probabilistic dispatch simulations of electric utility systems -- including the New England Power Pool, the state of Maharashtra (India), and individual U.S. utilities -- to identify the cost implications of alternative resource choices and planning assumptions.

Developed a generating unit dispatch plan to minimize fuel and operating costs for the Nantucket Electric Company, taking into account factors such as part load thermal efficiencies and system operating reserve.

Presented expert testimony before state regulatory commissions in dockets relating to electric utility planning, rate cases, and long term avoided costs:

Cooperative Utility Analysis

Responsible for developing the Vermont Electric Cooperative's power supply budgets since 1992. In retail rate proceedings, sponsored the Cooperative's power supply and transmission costs. Assisted Cooperative staff in the development of demand-side management and interruptible load programs. Assisted La Capra Associates staff in developing financial analyses supporting the Cooperative's negotiations with the Rural Utility Service, and presentation of its business plan before the U.S. bankruptcy court.

Electric Utility Resource Planning

Managed the development of Integrated Resource Plans for several electric utilities.

Used simulations to determine the amount of additional generating capacity that the Puerto Rico Electric Power Authority will require in order to maintain its system reliability objectives. Identified the factors that would most strongly affect the capacity need, and identified how variations in those factors would advance or defer the need for capacity. Supported the results in direct testimony before the Planning Board of Puerto Rico.

Developed "avoided cost" rates to represent the value of electric power from Qualifying Facilities, and from demand modifications associated with utility Demand-Side Management ("DSM") programs.

Electric Transmission Issues

Critically examined a long term transmission contract between two New England electric utilities. Identified inappropriate booking of transmission plant, and an overstatement of electrical losses on the seller's system. Developed written testimony before the Federal Energy Regulatory Commission. Participated in negotiation of a successful settlement, which includes a substantial refund of back charges and significant reduction in future charges.

Other Energy Analyses

Analyzed the technical and economic feasibility of self-generating steam and chilled water to serve the medical campus of Boston City Hospital and Boston University.

PROFESSIONAL EXPERIENCE:

- Electrical Planning Engineer, VERMONT DEPARTMENT OF PUBLIC SERVICE. October, 1988 to December, 1990.
- Power Cost Analyst, VERMONT DEPARTMENT OF PUBLIC SERVICE. June, 1986 to October, 1988.

EDUCATIONAL BACKGROUND:

- Sc.B. in Mechanical Engineering with Energy Conversion emphasis, **BROWN UNIVERSITY**, Providence, Rhode Island.
- EPRI Seminars on Utility Planning and Production Costing Techniques.
- Users' group and other training seminars associated with the UPLAN and ENPRO production costing models.

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set III
Dated April 17, 1997

Docket No. R-00973954

Q.45. On page 13, line 15, Dr. Jones states that "The hourly market clearing price within PJM will reflect the variable cost of the last unit dispatched..."

a) Please explain whether the market clearing price will reflect the last unit's incremental variable cost or its total variable cost, and the basis for Dr. Jones' understanding.

b) Dr. Jones states (page 31, line 15) that "the hourly market clearing price [in EGEAS] is the incremental cost of the last unit dispatched within PJM for each hour." If the last unit dispatched is dispatched at a load level where its incremental heat rate is lower than its average heatrate, will the marginal unit's variable costs not exceed its energy revenues? If not, please explain why not. If so, please explain why it is appropriate to assume that variable costs of one or more generating units dispatched in each hour would exceed the marginal revenues earned by such units in those hours.

A.45. a) The market clearing price will reflect the variable costs incurred by the marginal unit to produce its output.

b) If the last unit is dispatched at a load level where its incremental heat rate is lower than its average heat rate, the incremental dispatch price will be lower than the total variable costs of that unit. In a competitive market in which generators can bid their dispatch price, they would account for this factor in their bids for the production of blocks of energy. Although the EGEAS model does not perfectly take this issue into account, it models five loading blocks, which more accurately reflects the variable cost incurred by generators than does using average heat rates over the whole operating range of the generator.

EXHIBIT DCS-3

S.T. Jones

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set III
Dated April 17, 1997

Docket No. R-00973954

Q.64. Please provide the 1996 variable O&M costs that were used to represent each generating unit in Dr. Jones' EGEAS analysis. Please provide each unit's fuel costs and other O&M costs separately.

A.64. This response has been designated confidential pursuant to a Stipulated Protective Agreement between PP&L and the Office of Consumer Advocate.

Copies of this response will be provided to other parties upon request and execution of a Stipulated Protective Agreement.

EXHIBIT DCS-3

S. T. Jones

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set III
Dated April 17, 1997
Docket No. R-00973954

Q.67. This question refers to the Selected EGEAS Input Assumptions presented in Exhibit STJ-5.

a) Please provide the specific numbers (i.e. demands, fuel prices, etc.) listed as Assumptions;
b) Please provide the workpapers associated with the derivation of each item, and the source documents that were relied upon.

A.67. a) See the specified documents or the responses to the following questions for base year data:

Fuel Prices - See the response to Question 64 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.
O&M Costs - See Attachment 1, Question 64 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.
Demand - See Attachment 1.
SO2 Emission Allowances - See Attachment 2.
Imports - See response to Question 69 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.
Cost of New Units - See response to Question 74 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.
Nuclear Capacity Factor - See Exhibit STJ-6
Heat Rate - See response to Question 74 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

b) See the following documents or Question numbers.

Fuel Prices - See the response to Question 89 of the Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

O&M Costs - See the response to Question 65 of the Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

Demand - See response to Question 72 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

SO2 Emission Allowances - See Attachment 2.

Imports - See response to Question 69 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

Cost of New Units - See response to Question 74 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

Nuclear Capacity Factor - See Exhibit STJ-6

Heat Rate - See response to Question 74 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

PEAK LOAD AND ENERGY FORECAST FOR THE 1997 BASE CASE

NOTE: THE FORECAST IS BASED ON THE PL 11/96 LOAD FORECAST FOR PL LOADS
PJM LOADS USE THE 7/96 LAS REPORT FOR ALL 20 YEARS

	ENERGY FORECAST (GWH)				PEAK LOAD FORECAST (MW)				
YEAR	PJM LOAD FORECAST 7/96 LAS	PL GRP. LOAD FORECAST 7/96 LAS	7CO LOAD FORECAST 7/96 LAS	PL GROUP 11/96 LOAD FORECAST	PJM 7/96 LAS	PL SUMMER PEAKS 7/96 LAS	7CO 7/96 LAS	WINTER PL GROUP 11/96 LOAD FORECAST	SUMMER PL GROUP 11/96 LOAD FORECAST
1996	242319	36045	206274	36536	47144	5856	41288	6870	5910
1997	245652	36798	208854	37001	47716	5979	41738	6960	5990
1998	249320	37656	211764	37424	48338	6110	42228	7030	6060
1999	253004	38520	214484	38204	48960	6233	42727	7120	6160
2000	257116	39000	218116	38538	49644	6354	43290	7210	6260
2001	260836	39727	221109	39283	50234	6477	43757	7320	6360
2002	264248	40466	223782	39964	50933	6598	44338	7450	6480
2003	267769	41209	226560	40614	51564	6720	44825	7550	6590
2004	270319	41958	228361	41286	51971	6852	45119	7670	6710
2005	274208	42685	231523	41959	52592	6973	45619	7790	6820
2006	278720	43426	235294	42631	53372	7095	46277	7900	6930
2007	283266	44195	238073	43314	54184	7227	46957	8010	7040
2008	288096	44962	243144	43898	54982	7356	47624	8130	7160
2009	292029	45698	246331	44682	55764	7482	48282	8250	7280
2010	296434	46474	249960	45376	56555	7613	48942	8370	7390
2011	300786	47230	253556	46027	57350	7745	49605	8470	7500
2012	305676	47995	257681	46711	58150	7877	50273	8600	7610
2013	309787	48791	261006	47427	58973	8008	50965	8720	7730
2014	314415	49576	264840	48111	59803	8141	51662	8830	7850
2015	318965	50322	268643	48762	60626	8263	52365	8940	7960
2016	323749	51072	272677	49414	61477	8386	53091	9060	8070

OCA-III-67

Forecast of SO2 Emission Allowance Prices

Year	SO_2 Price
1996	80
1997	89
1998	98
1999	106
2000	115
2001	118
2002	121
2003	124
2004	127
2005	130
2006	133
2007	137
2008	140
2009	144
2010	147
2011	151
2012	155
2013	159
2014	162
2015	167
2016	171

Note: Data through 2000 are from "The Potential Market Value of SO2 Allowances," ICF/Kaiser, June, 1996. Prices thereafter are escalated at 2.5% inflation assumption.

S.T. Jones

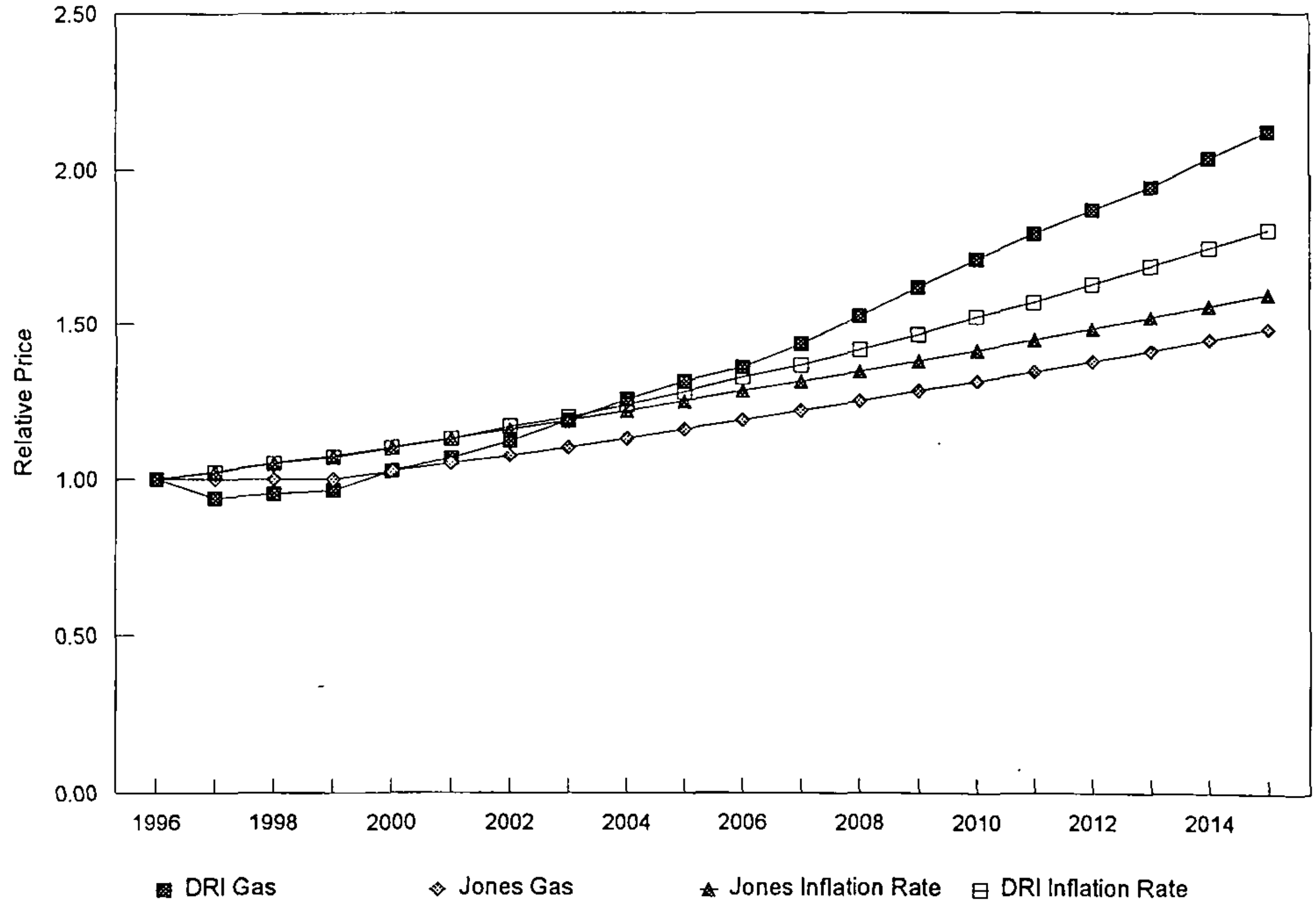
Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set III
Dated April 17, 1997
Docket No. R-00973954

Q.68. To the extent not provided in the previous response, please explain how the fuel prices for each PJM generating unit were derived.

A.68. See the response to Question 67 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997.

EXHIBIT DCS-4a

Comparison: Gas Price Escalation Forecasts



Comparison: Oil Price Escalation Forecasts

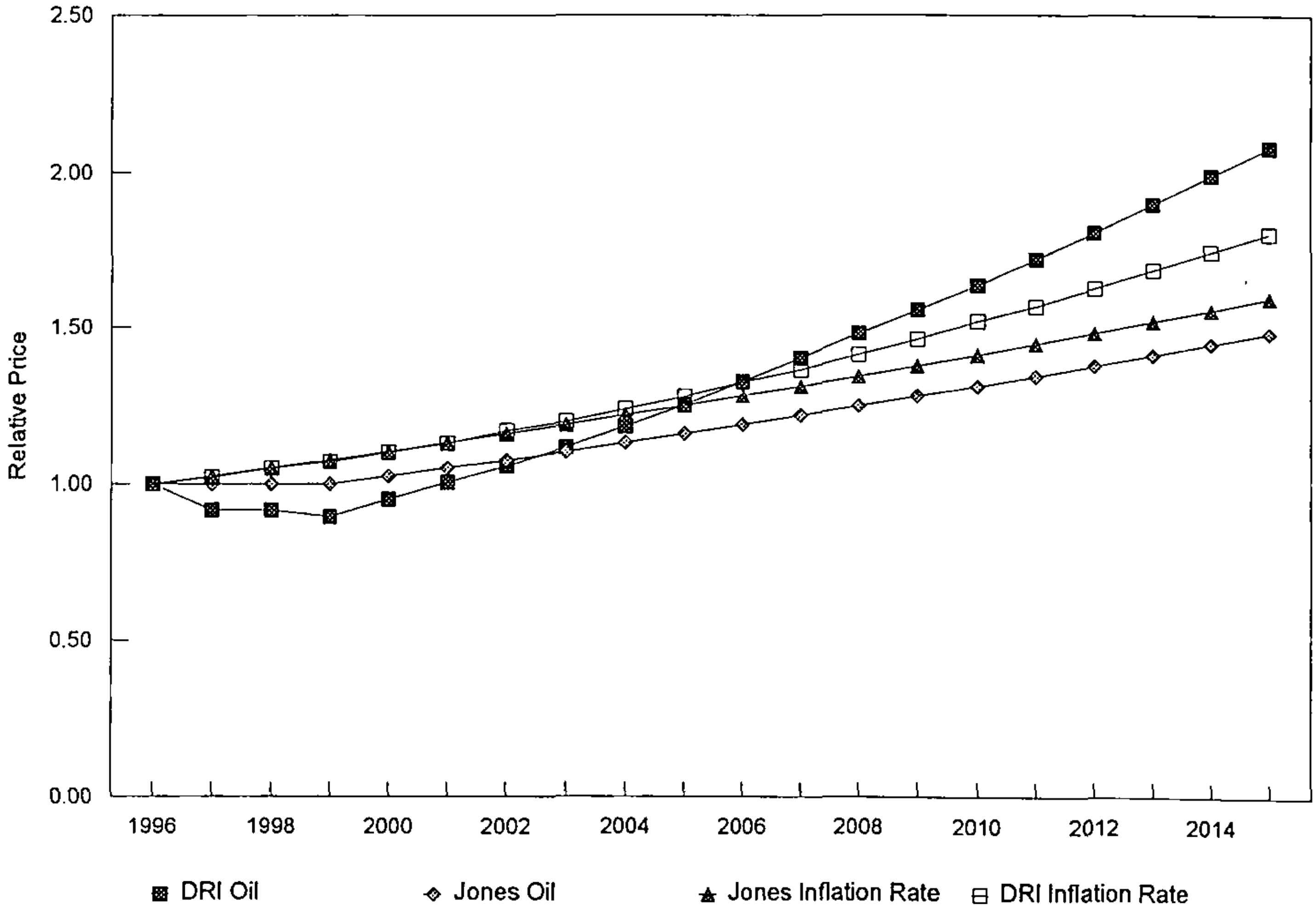
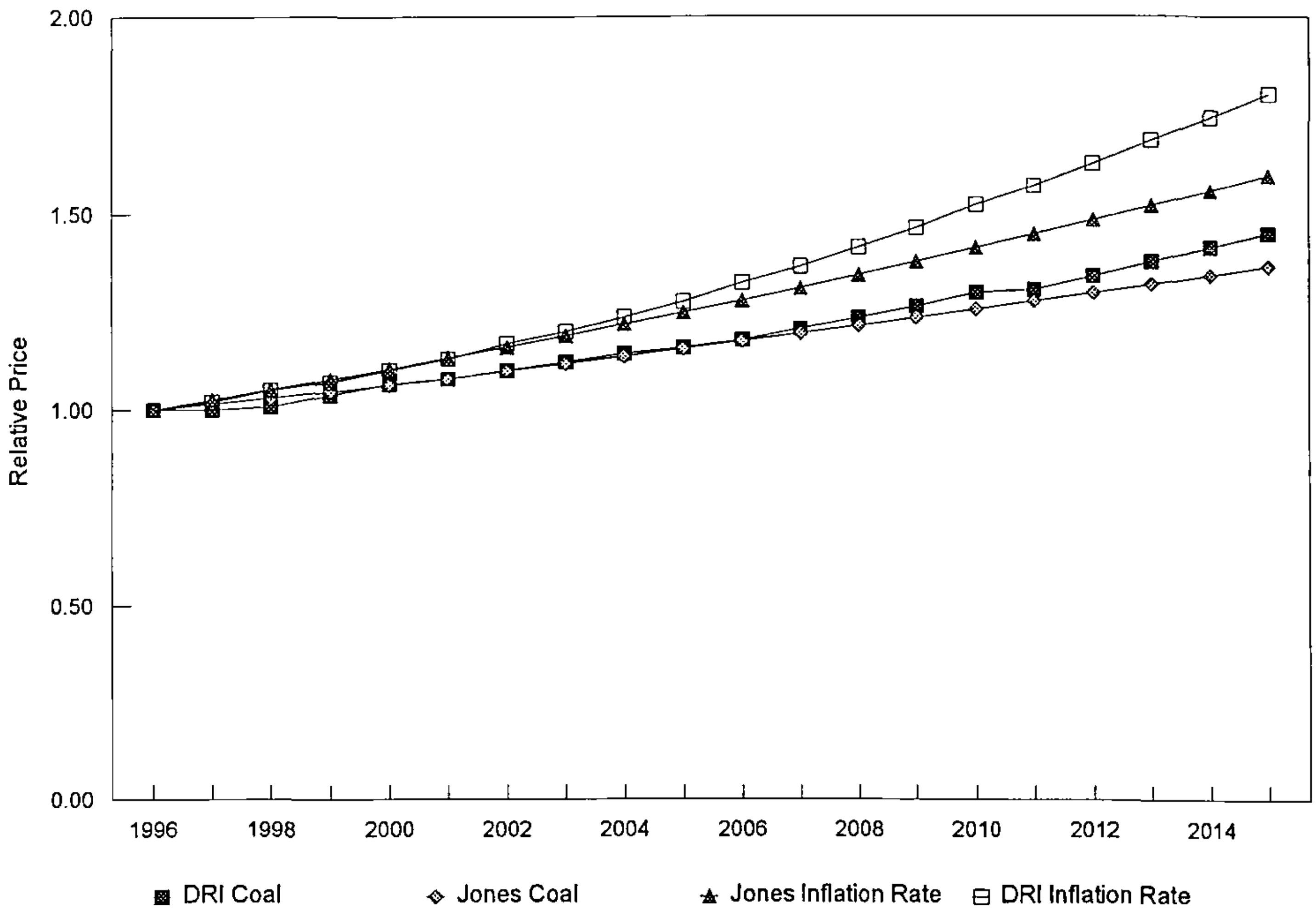


EXHIBIT DCS-4c

Comparison: Coal Price Escalation Forecasts



S. T. Jones

Pennsylvania Power & Light Company
Response to Interrogatories of the
Office of Small Business Advocate, Set I
Dated May 22, 1997
Docket No. R-00973954

Q.24. Regarding the capacity price forecast shown in Exhibit STJ 8 and discussed at pages 45-46 of your testimony:

a. Please describe in detail how these capacity prices are determined.

b. Please detail the assumptions used to develop annual capacity costs ($ per kW) for new combustion turbine and combined cycle plants, including but not limited to construction costs, capital costs (return on debt, return on equity, capital structure), inflation rates, tax rates, and depreciation assumptions. Please include an example showing the calculation of the annual capacity cost for a combined cycle facility for the year 2010.

c. Please provide all workpapers used to develop the capacity prices shown.

A.24.

a. The capacity prices used as the basis for Dr. Jones' forecast were based on data given to him by PP&L personnel. PP&L is a net seller of capacity and has data based on actual transactions in both the short-term and forward markets for capacity. Dr. Jones based his projections of the price of capacity on his knowledge and understanding of the behavior of markets in capital intensive industries when there is an excess supply of capacity.

The data from PP&L suggests that in the 1996 base year, short-term capacity prices were significantly lower than the cost to add new capacity, which is true of markets in which there is a capacity surplus. Data on the forward market suggest that market expectations will cause prices to remain below that needed to add new capacity for the next several years.

Given the current capacity surplus and the expectation of a capacity deficit in PJM by the year 2002, Dr. Jones used his knowledge of capital markets and the experience of other industries such as natural gas, transportation, and metals to forecast capacity prices in PJM. Dr. Jones' forecast reflects the behavior of competitive markets as supply tightens and a potential shortage is expected by buyers and sellers of electricity. As the market tightens, buyers of capacity will begin to contract for forward capacity at higher prices. The spot market for capacity will tend to react to the forward market, reflecting a price increase for near term capacity.

b. See the response to Question 74 of Interrogatories of the Office of the Consumer Advocate, Set III, Dated April 17, 1997.

c. To the extent such workpapers exist, they were prepared at the request and under direction of counsel and, as such, constitute confidential and privileged attorney work-product.

DRI FUEL PRICE ESCALATION RATES

YEAR	GAS	COAL	F02	FO6
1997	-6.0%	0.0%	-4.9%	-8.2%
1998	1.3%	0.7%	1.4%	0.0%
1999	1.3%	2.8%	-0.4%	-2.3%
2000	6.6%	2.8%	5.7%	6.3%
2001	3.9%	1.3%	5.2%	5.4%
2002	5.2%	2.0%	5.1%	5.2%
2003	5.7%	2.0%	5.3%	5.7%
2004	5.7%	1.9%	5.3%	5.8%
2005	4.4%	1.3%	5.5%	5.9%
2006	3.6%	1.9%	5.5%	5.9%
2007	5.6%	2.4%	5.5%	5.8%
2008	6.4%	2.4%	5.4%	5.7%
2009	6.0%	2.3%	5.0%	5.2%
2010	5.7%	2.8%	4.9%	5.1%
2011	4.9%	0.6%	5.0%	5.1%
2012	4.2%	2.7%	4.9%	5.0%
2013	4.1%	2.7%	4.8%	5.0%
2014	4.7%	2.6%	4.8%	4.9%
2015	4.3%	2.5%	4.6%	4.5%

YEAR	PROJECTED PJM MARKET PRICES*				
	PP&L	PECO			OCA
	ERG	ICF	EDS	PHB	LACAPRA
1999	$24.51	$26.40	$25.70	$23.00	$24.61
2000	$26.31	$29.20	$28.20	$25.70	$27.08
2001	$28.34	$32.10	$31.90	$29.20	$29.89
2002	$29.71	$33.30	$33.30	$30.90	$31.31
2003	$30.59	$34.30	$34.90	$32.60	$33.19
2004	$31.48	$35.70	$36.40	$34.50	$34.64
2005	$31.02	$37.10	$37.60	$36.10	$37.22
2006	$32.14	$38.80	$38.80	$37.80	$39.70
2007	$34.71	$40.30	$40.30	$39.60	$41.76
2008	$35.82	$42.10	$42.10	$41.50	$44.26
2009	$37.05	$43.50	$43.70	$43.50	$45.80
2010	$38.16	$45.30	$45.70	$45.40	$48.76
2011	$38.28	$46.80	$47.30	$47.30	$50.68
2012	$39.39	$48.50	$49.00	$49.40	$53.00
2013	$41.51	$50.30	$50.70	$51.50	$55.13
2014	$41.74	$52.20	$52.90	$53.80	$57.64
2015	$42.85	$54.00	$55.10	$56.10	$60.37

* All-hours (baseload) energy and capacity

YEAR	PP&L WEIGHTED GENERATION PRICE, $/MWH
1999	26.61
2000	29.99
2001	33.72
2002	35.29
2003	37.33
2004	38.61
2005	41.56
2006	44.26
2007	46.12
2008	48.95
2009	50.67
2010	53.87
2011	55.92
2012	58.30
2013	60.85
2014	63.59
2015	66.23

EXHIBIT DCS-7

PJM MARKET PRICE ESTIMATE

YEAR	ENERGY $/MWh ALL-HOURS	CAPACITY $/KW-YR	TOTAL $/MWh ALL-HOURS
1999	22.35	19.73	24.61
2000	23.61	30.43	27.08
2001	25.14	41.67	29.89
2002	26.38	43.12	31.31
2003	28.14	44.20	33.19
2004	29.42	45.66	34.64
2005	31.84	47.12	37.22
2006	34.12	48.91	39.70
2007	36.01	50.38	41.76
2008	38.30	52.19	44.26
2009	39.64	54.02	45.80
2010	42.34	56.18	48.76
2011	44.06	57.98	50.68
2012	46.14	60.12	53.00
2013	48.02	62.29	55.13
2014	50.28	64.47	57.64
2015	52.76	66.66	60.37

OCA STATEMENT NO. 2-S

8/25/97
Hrg
jav

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF PENNSYLVANIA POWER & LIGHT COMPANY FOR APPROVAL OF ITS RESTRUCTURING PLAN UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE	:	DOCKET NO. R-00973954

SURREBUTTAL TESTIMONY

OF

DOUGLAS C. SMITH

On Behalf of:

OFFICE OF CONSUMER ADVOCATE

AUGUST 1997

Surrebuttal Testimony of Douglas C. Smith

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Douglas C. Smith. My business address is La Capra Associates, 333 Washington Street, Suite 855, Boston, MA 02108.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted OCA Statement No. 2 and accompanying Exhibits DCS-1 to DCS-9.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will begin by revising my projection of PJM generation market prices to reflect certain corrections. I will also present an additional scenario of market prices based on an alternative fuel price forecast. I will then respond to issues and critiques raised by PP&L in the rebuttal testimony of Dr. Scott Jones and Jonathan Falk, and I will compare several key features of my analysis to that of Dr. Jones.

Revision to OCA Generation Market Price Analysis

Q. PLEASE EXPLAIN THE REVISIONS THAT YOU HAVE MADE TO YOUR MARKET ANALYSIS.

A. The first change is to revise the base fuel prices assumed for generating units within the PJM Interconnection. Specifically, I have developed my revised base year 1996 fuel prices from

FERC Form 423, rather than the FERC Form 1 as used in my initial analysis. My revised analysis reflects actual base year fuel prices for each major fuel type, for each major utility in PJM. While this change was made to address certain concerns raised by PECO in Docket R-00973953 regarding the basis of FERC Form 1 data, the net effect of this change on market prices was not large.

A second, more meaningful, change was to increase the assumed price change from 1996 to 1997 to more accurately reflect the DRI fuel price forecast. This change is intended to address a valid concern raised by PP&L's Dr. Jones with respect to the consistency of base fuel prices and escalation rates in my initial analysis. In short, I learned that actual 1996 natural gas prices for PJM generating units were significantly higher than reported in DRI's Fall 1996/Winter 1997 fuel price forecast. By applying DRI's forecast 1997 escalation rate to actual 1996 gas prices, my initial analysis overstated the forecasted price of energy from gas-fired units. The differences for other fuels were small. The effect of this correction is to lower my estimate of generation market prices through the planning horizon, relative to my initial analysis in this case.

Third, I adjusted the way purchases from outside PJM were represented in the ENPRO dispatch simulation model, by increasing the hourly flexibility of energy imports from ECAR. The effect of the change is to increase the amount of PJM energy imports and lower the projected PJM market energy price modestly in the near term, with the price effect declining over time. I also replaced an abrupt drop in imports assumed in my initial analysis with a smoother decline over a six-year period; the effect of this change was minimal.

Q. **DID YOU MAKE ANY OTHER CHANGES?**

A. My only other change was to adjust the assumed additions of combined cycle ("CC") and simple cycle combustion turbine ("CT") capacity in PJM to reflect the changes in market resources and prices (i.e., different mix of CC and CT capacity to reflect the revised base fuel price assumptions). The methodology, analytical tools, and other input assumptions in the revised analysis are unchanged from those of my initial testimony.

Q. **WHAT IS THE RESULT OF THESE CHANGES?**

A. The results of my revised market price analysis are presented in Exhibit DCS-10 (projected all-hours market prices) and Exhibit DCS-11 (market prices projected to be realized by PP&L's generating units). From 1999 to 2015, the levelized market price of power in my revised analysis is roughly 2 percent lower than my initial analysis. Based on the projected generation market revenues and variable costs associated with this scenario, Mr. La Capra has estimated the stranded costs associated with PP&L's generating sources.

Q. **DID YOU EXAMINE AN ADDITIONAL SCENARIO OF FOSSIL FUEL PRICES?**

A. Yes. My initial analysis in this proceeding and the revised analysis described above are based on DRI's Fall 1996/Winter 1997 forecast of fuel prices in the mid-Atlantic region. This is the same fuel price forecast upon which PECO bases its analysis of generation market prices and stranded costs in Docket R-00973953.

I understand that DRI has issued a Spring, 1997 revision to its forecast of fuel prices in the mid-Atlantic region. The Spring, 1997 revision features significantly lower prices for natural gas (the fuel assumed by PECO and PP&L to be burned at most new generating units in PJM) and oil. All else being equal, this change would tend to decrease projected PJM generation market prices (relative to the Fall 1996/Winter 1997 version) and increase projected stranded generation costs for PP&L and PECO. At the same time, coal is the predominant fuel burned by PP&L and PECO fossil-fired generating units, and will therefore affect the Company's costs. The Spring 1997 DRI forecast features an increase in coal prices relative to the Fall 1996 version; this change would also tend to increase projected stranded generation costs for PP&L and PECO.

PECO provided DRI's forecast of delivered fuel prices, although not the forecast document itself, in Docket R-00973953. PECO also submitted alternative analyses of market prices and stranded costs based on the Spring 1997 DRI forecast.

Since fuel price assumptions are a significant issue in this case, and since PECO has submitted updated analyses in Docket R-00973953 using DRI's Spring, 1997 fuel price forecast, the OCA asked me to test the effect of that forecast on my estimate of generation market prices.

I therefore conducted an additional scenario of market prices, using the same methodology, tools and other major input assumptions as used in my initial analysis.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ALTERNATIVE FUEL PRICE SCENARIO.

A. The results of my market analysis for the DRI Spring, 1997 fuel price forecast are presented in Exhibit DCS-12 (projected all-hours market prices) and Exhibit DCS-13 (market prices projected to be realized by PP&L's generating units). From 1999 to 2015, the levelized market price of power in my revised analysis is about three percent lower than my revised analysis (Exhibits DCS-10 and DCS-11). Based on the projected generation market revenues and variable costs associated with this scenario, Mr. La Capra has estimated the stranded costs associated with PP&L's generating sources.

Selective Updating

Q. DR. JONES STATES (PAGE 8) THAT INTERVENORS "SELECTIVELY ADOPT FUEL PRICE FORECASTS THAT WERE KNOWN TO BE OUT OF DATE PRIOR TO THEIR PREPARATION OF TESTIMONY IN ORDER TO OBTAIN THE RESULTS THEY SUPPORT." IS THAT THE CASE?

A. No. My initial analysis of generation market prices was based on DRI's Fall 1996/Winter 1997 fuel price forecast, which was presented by PECO in Docket R-00973953. I first became aware of DRI's Spring, 1997 fuel price forecast on July 18, 1997 when PECO filed its rebuttal testimony.

Fuel Price Assumptions

Q. **AT SEVERAL POINTS IN HIS TESTIMONY, DR. JONES REFERS TO ONE OR MORE FUEL PRICE FORECASTS AS "INTERVENORS" FORECASTS. PLEASE COMMENT ON THIS DESCRIPTION.**

A. The market price analyses presented in my testimony reflect fuel price forecasts developed by DRI as part of its subscription forecasting services. I understand that the analyses conducted by PPLICA witness Randall Falkenberg reflect fuel price assumptions outlined in the U.S. Energy Information Administration's 1997 "Annual Energy Outlook." On behalf of PP&L, Dr. Jones developed his own fuel price forecast.

Q. **PLEASE COMMENT ON DR. JONES' CRITIQUE OF THE DRI AND EIA FUEL PRICE FORECASTS UTILIZED BY INTERVENORS IN THIS PROCEEDING.**

A. Dr. Jones raises the concern that the DRI and EIA fuel price forecasts predict a widening of the existing spreads between oil, gas, and coal prices. He states (page 31) that "Just ten years into the forecast, the odds that the gap between oil and coal prices predicted by DRI could materialize are roughly 33,000 to 1." Dr. Jones goes on to state that "there is essentially no chance that fuel prices will behave the way intervenors predict." While Dr. Jones did not provide the details of his analysis, I have several observations.

First, Dr. Jones appears to be referring to a statistical analysis of historical fuel prices. His description of probabilities boils down to the assumption that historical fuel price behavior will definitely be an accurate predictor of future prices, and that forecasted price relationships that vary from the historical relationships are necessarily wrong.

Second, Dr. Jones' Exhibit STJ-16 contains sustained periods when actual prices deviated significantly from the trend. In fact, the exhibit shows that actual oil prices have exceeded Dr. Jones' cited "average" price of $15.50/barrel for virtually all of the past twenty years.

Finally, with respect to natural gas, Dr. Jones asserts (page 59) that "added gas reserves can be coaxed into the market without a large increase in expected natural gas prices" One of his reasons (Exhibit STJ-20) is that "NUGs do not increase gas consumption. Increased sales of electricity increase gas consumption." This logic is mistaken. While gas-fired combined cycle generation is projected to serve a large fraction of electric demand growth, the following other factors also have increased or will tend to increase gas consumption in the electric sector:

- Complete or partial fuel switching at existing generating stations;
- Efficient new gas-fired units constructed to meet demand-driven capacity needs will tend to displace significant amounts of fossil-fired generation in the energy dispatch;
- New gas-fired units may replace output from existing units that retire. My analysis assumes large scale additions of gas-fired generation for just this purpose.

Q. DOES DR. JONES' DISCUSSION WITH RESPECT TO FUEL PRICES PROVIDE A CLEAR ILLUSTRATION OF HIS PROPOSED FORECAST?

A. No. Dr. Jones' proposed escalation rates for natural gas and oil are constant nominal prices through 1999, followed by increases of 2.5 percent per year thereafter. Several aspects of Dr. Jones' discussion leave the impression that his proposed escalation path is applied to actual 1996 prices, which most forecasters believe were exceptionally high. The Commission should be aware that Dr. Jones does not apply his escalation forecast to the actual 1996 prices experienced by PJM generating units, but rather to assumed base prices that are roughly 20 percent lower.

Q. PLEASE EXPLAIN.

A. Dr. Jones' Exhibits STJ-12 and STJ-13 both show Dr. Jones' oil price assumptions, along with those of other forecasters, as starting from the same base (1996) price. Dr. Jones shows his forecast as constant at the 1996 value for three years, followed by nominal increases of 2.5 percent per year.

In contrast, Dr. Jones' base year fuel prices for PJM generating units were provided by PP&L staff, and are clearly dated assumptions (Jones initial testimony, page 28). The base year prices assumed in Dr. Jones' analysis for PJM steam units fired by oil, gas, and coal (as provided in confidential data response OCA-III-64), are substantially lower than the 1996 actual. This can be ascertained by comparing the assumptions utilized in Dr. Jones' data response to the actual 1996 fuel prices for the same units as reported in EIA, Form 423.[1]

---

[1] Annual prices reported in the FERC Form 1 are similar.

Whether or not Dr. Jones was aware how much lower the PJM fuel costs in his market price analysis understate the actual 1996 costs, his Exhibits STJ-12 and STJ-13 provide an incorrect indication of what his fuel price forecast actually represents.

Q. WHAT PLANNING PERSPECTIVE CAN YOU OFFER THE COMMISSION REGARDING FUEL PRICE ASSUMPTIONS IN THE CONTEXT OF THIS CASE?

A. Dr. Jones is probably correct when he states that fuel price assumptions will have the single largest impact on projected market-clearing energy prices. For this reason, it is important that in establishing stranded costs in this proceeding, the Commission recognize that there is a significant degree of uncertainty associated with future fuel prices (and therefore generation market prices).

Historical fuel prices have varied substantially over time (and the variations have often lasted for sustained periods), as Dr. Jones' Exhibit STJ-16 illustrates for the example of oil. In this proceeding, ratepayers are effectively being asked to make commitments regarding PP&L's generation assets based on a single point forecast of future fuel prices. The Commission should therefore pay attention to current fuel price forecasts, but also to the possibility that actual outcomes during the life of PP&L's generation assets will differ (and possibly significantly) from today's forecasts.

Q. HAS THE COMPANY PRESENTED SENSITIVITY ANALYSES TO QUANTIFY HOW ITS STRANDED GENERATION COSTS WOULD TURN OUT IF ACTUAL

FOSSIL FUEL PRICES TURN OUT DIFFERENTLY THAN FORECAST BY DR. JONES?

A. No, Dr. Jones presents a single market price analysis based on his fuel price forecast. OCA witness Richard La Capra will discuss the potential effects of alternative fuel and market price outcomes on PP&L's ratepayers, the relative risks to ratepayers and to the Company, and how these considerations affect the selection of planning assumptions in this case.

<u>Cost and Timing of Capacity Additions in PJM</u>

Q. MR. SMITH, IN YOUR INITIAL TESTIMONY YOU QUESTIONED THE COST AND TIMING OF NEW GENERATION ALTERNATIVES ASSUMED IN DR. JONES' MARKET PRICE ANALYSIS. ARE THOSE CONCERNS STILL VALID?

A. Yes, they are. Dr. Jones' rebuttal testimony touches on this area in several respects, but his rebuttal is not convincing. It is not clear whether Dr. Jones' forecasted market prices would be sufficient to support the amount and type of generating capacity that both Dr. Jones and I assume will be constructed in PJM.

Q. PLEASE COMMENT ON THE PROJECT ECONOMIC ANALYSIS THAT DR. JONES HAS PRESENTED TO ILLUSTRATE THE VIABILITY OF NEW COMBINED CYCLE CAPACITY.

A. Dr. Jones' viability analysis, which is presented in Exhibits STJ-28a and STJ-28b, is flawed in several respects. Contrary to Dr. Jones' conclusions, the analysis indicates that his market price projections would not be sufficient to support the additions of combined cycle capacity that he assumes will be built in PJM.

First, the assumed capital cost of $489/kW is unrealistically low, and inexplicably differs from the $595/kW capital cost that Dr. Jones claims (table pages 68-69) that he assumed for new combined cycle units in his market price analysis.

Second, Dr. Jones' projection of project expenses appears to lack at least two legitimate costs -- property taxes and project insurance -- which developers of new generating capacity will face. I expect that these costs would amount to at least one percent of the initial project capital cost, which represents about $5/kW-year.

Finally, Dr. Jones' viability analysis utilizes a heatrate of 6,650 BTU/kWh for the combined cycle option, which is inexplicably lower than the 7,000 BTU/kWh figure Dr. Jones claims (table pages 68-69) that he assumed for new combined cycle units. The 6,650 BTU/kWh figure appears to be the heatrate reported in the GTW source document for a combined cycle unit based on three of ABB's GT11N2 turbines, based on the **lower heating value** of the fuel. As I will explain further below, this method is incorrect, and understates the unit's fuel cost by about 11 percent. In other words, the CC unit whose viability is tested on Exhibits STJ-28a and 28b would actually be about 11 percent less efficient than Dr. Jones has assumed.

Each of these inconsistencies tends to understate the cost of power from a new combined cycle plant. Correcting Dr. Jones' assumptions for capital cost, operating expenses, and heatrate -- even if only to reflect the assumptions that he claims to be using in this proceeding -- would substantially reduce the projected cash flow and return for the hypothetical combined cycle project. After these adjustments, Dr. Jones' assumed combined cycle option would probably not be economically viable if it were to receive his forecasted market energy and capacity prices.

Q. WHAT IS THE SIGNIFICANCE OF THIS RESULT?

A. In the competitive generation market, developers of new generating capacity will build that capacity when their expected returns from the market are sufficient to justify the investment, and when the needed financing can be obtained. While Dr. Jones' analysis assumes that large amounts of new combined cycle capacity will be built in PJM, his market price results do not appear to provide those combined cycle units with sufficient returns to project investors. This is not a reasonable outcome over the long term.

Q. WHAT ABOUT DR. JONES' ARGUMENT THAT GENERATORS WILL "RACE TO INVEST" IN NEW PLANTS, DESPITE LOW INITIAL MARKET PRICES?

A. Dr. Jones states (page 81) that:

> "The phenomenon of racing to invest is a common pattern in highly competitive, capital intensive industries. The timing of investment is determined by investors weighing initial operating losses against expected profits obtainable in later years..."

This statement is fair, but the implication that Dr. Jones draws from it is not. Investors will need to expect reasonable returns on their investment, over their investment horizon. While it is possible that investors in new generating capacity will accept losses in the initial years of operation, only projects which meet investors' total return expectations (i.e. above-average returns expected later) -- and can obtain financing -- will actually be built. Dr. Jones' projected capacity prices in the first several years of the analysis would produce losses for the assumed capacity additions in those years, and he has presented no convincing evidence to justify the assumption that market entrants will accept below-market returns in the near term or the long term. It is appropriate for the Commission to assume that market capacity prices will converge with the cost (including a reasonable return on equity) of new peaking capacity options, and that market prices (including capacity and energy revenues) for baseload units will converge with the cost of new combined cycle generation.

Q. PLEASE COMMENT ON THE "CONSERVATISM" OF DR. JONES' COMBINED CYCLE CAPITAL COST AND HEATRATE ASSUMPTIONS, AS ASSERTED ON HIS EXHIBIT STJ-25.

A. New combined cycle plants are projected to have a strong effect on PJM generation market prices. Exhibit STJ-25 attempts to show that Dr. Jones has represented the combined cycle option using "conservative" assumptions that will tend to overstate market prices and the value of PP&L's generating units. In fact, Exhibit STJ-5 is an inappropriate comparison which incorrectly represents Dr. Jones' assumptions in several respects.

First, Dr. Jones has represented his combined cycle option at its assumed 7,000 BTU/kWh heatrate (HHV), while the unadjusted data from the 1996 GTW Handbook represent other generating units at their LHV heatrates. Second, Dr. Jones has represented his combined cycle option at its assumed capital cost of $595/kW (based on summer capacity rating), while the unadjusted GTW prices reflect the units' net output at ISO conditions (59 degrees F). For these reasons, the "ERG Estimate" point on Exhibit STJ-25 is simply not comparable to the range of points on the lower left entitled "Unadjusted Data From 1996 GTW Handbook." In order to compare assumptions accurately, it is necessary to express the units' heatrates and costs on the same basis, as Mr. Falkenberg of PPLICA appears to have done in developing the range of points entitled "Adjusted Data From 1996 GTW Handbook."

Second, Dr. Jones has represented the ERG combined cycle option ("ERG Estimate") based on its assumed total capital cost of $595/kW, which includes all indirect plant costs and financing costs. In contrast (and as noted on the exhibit), the prices for all other generating units from the GTW Handbook include only the manufacturers' cost of plant equipment. Again, the comparison is inappropriate. If one were to adjust the ERG data point to reflect capital cost on the same basis as the manufacturer costs, it would fall within the range of options as reported by GTW not the Conservative Region as indicated on the exhibit as filed.

Q. MR. SMITH, PLEASE COMPARE THE HEATRATE ASSUMPTIONS THAT YOU HAVE USED FOR NEW COMBINED CYCLE UNITS TO THOSE ASSUMED BY DR. JONES ON BEHALF OF PP&L.

A. My analysis assumes that new combined cycle units in PJM will produce energy at an annual average heatrate of 6,700 BTU/kWh. This average is intended to reflect fuel consumption over the range of output levels that the combined cycle unit will operate during the year. This includes relatively efficient operation at less than full output, and operation over the range of seasonal temperatures experienced in PJM. My "as-operated" heatrate assumption of 6,700 BTU/kWh therefore corresponds to a somewhat lower full load average heatrate.

Dr. Jones assumes a combined cycle heatrate of 7,000 BTU/kWh; I do not know whether this assumption is intended to represent an "as-operated" heatrate assumption comparable to mine, or the full load average heatrate.

Q. HOW DO THESE HEATRATE ASSUMPTIONS COMPARE TO COMMERCIALLY AVAILABLE COMBINED CYCLE UNITS?

A. The 6,700 BTU/kWh as-operated heatrate that I assume for new combined cycle units is better than any commercially operating combined cycle unit of which I am aware. Dr. Jones suggests (page 71) that new models offer heatrates of about 6,000 BTU/kWh; this comparison is incorrect, and reflects a basic misunderstanding of the data presented by the *Gas Turbine World 1996 Handbook* ("GTW").

The difficulty is that Dr. Jones' 7,000 BTU/kWh figure reflects the higher heating value of natural gas, but the GTW clearly identifies its heatrate figures as based on the lower heating value of gas.[2] For natural gas, the difference between HHV and LHV is about 11 percent. In order to calculate the cost of fuel ($/Mwh) for a generating unit, it is critical to represent both the fuel price and the heatrate in terms of either HHV or LHV. In the U.S., fuel prices and heatrates are virtually always represented in terms of HHV. This means that the future 6,000 BTU/kWh (LHV) units cited by Dr. Jones are at best comparable to my 6,700 BTU/kWh (HHV) assumption in this proceeding, and only a few percent more efficient than Dr. Jones' assumption.

Q. DR. JONES STATES WITH RESPECT TO NEW GAS TURBINE COSTS, "THERE IS NO REASON TO EXPECT COSTS TO CEASE THEIR DECLINE." IS THIS A FAIR REPRESENTATION?

A. No, it is not. Dr. Jones observes (page 72) that prices for large single-shaft machines have dropped to a historic low, as described by the GTW. While this is true (and both he and I have assumed that these price declines will be permanent), there is more to the story. For example, Dr. Jones' GTW source goes on to observe:

> "New machines are often heavily discounted to get production prototypes into the field. Some are downright 'giveaways' to get operating hours logged on and provide a place to showcase to prospective customers. Later, prices are increased to normal levels as the design is accepted into the marketplace. Older machines, besides being

[2] The difference between higher heating value ("HHV") and lower heating value ("LHV") is the heat used to vaporize water produced during combustion of the fuel. This heat is not "usable" in the context of a power plant, and its treatment in the context of heatrates and fuel prices is a matter of convention.

less efficient, can often be steeply discounted since the original costs of engineering design, product development, and production tooling and facilities have long since been repaid." (*Gas Turbine World 1996 Handbook*, Volume 17, page 1-03).

The point here is that while turbogenerator prices and total plant costs have declined in recent years, the savings have not come exclusively through technological improvements and it is not certain that the trend will continue. There is evidence to suggest that some of the price declines have been attributable to temporary market conditions that may not apply over the planning horizon.

Q. MR. SMITH, PLEASE SUMMARIZE THE BASIS OF YOUR COMBINED CYCLE AND COMBUSTION TURBINE CAPITAL COST ASSUMPTIONS, AND WHY THEY ARE APPROPRIATE IN THE CONTEXT OF THIS PROCEEDING.

A. My analysis assumes total capital costs of $550/kW ($1996) for new CC units, and $290/kW ($1996) for new CT units. I developed these estimates based on a review of materials submitted by witnesses in Docket R-00973953, as well as other industry planning documents and trade press reports.

Exhibits DCS-15 and DCS-16 illustrate the specific derivation of my capital cost assumptions for the CC and CT units, respectively. The major features are:

- Equipment costs based on the low end of packages estimated by Gas Turbine World's 1996 Handbook;
- Additional plant component costs assuming major scale economies (e.g., electrical and gas interconnection costs assumed to be shared as part of a 1,125 MW station);
- Optimistic (low) assumptions for indirect costs such as interest during construction, and project development;
- No costs for additional ("non-vanilla") plant features which actual projects may choose for purposes such as reliability enhancement, boosting seasonal output, or meeting stringent emission control requirements.

In total, my assumed capital costs for new CT and CC units are optimistic, and will be difficult for actual projects to achieve in the near term. My capital cost assumptions are, in fact, lower than those Dr. Jones has used on behalf of PP&L in this proceeding. I chose to base my market price analysis on these optimistic capital cost, carrying charge, and heatrate assumptions in order to reflect the potential that some market entrants will be able to achieve advantages -- through unique site features or technological improvement, as raised by Dr. Jones.

Q. DOES REPOWERING OF EXISTING GENERATING UNITS PROVIDE A SOURCE OF POWER DRAMATICALLY CHEAPER THAN THE NEW COMBINED CYCLE UNITS IN YOUR ANALYSIS?

A. No. Repowering typically refers to the conversion of an existing steam unit to a combined cycle unit, replacing an aging boiler with one or more CT's and a heat recovery steam generator. Alternatively, it may be possible to retrofit an existing CT with a heat recovery steam generator and steam turbine generator. The theoretical advantage of repowering is to obtain the efficiency of CT and steam generation in a combined cycle, at lower capital cost than a new CC plant. PP&L witness Jonathan Falk raises the possibility (page 14) that repowering of existing CT units may become common, although he provides no support for that proposition.

I believe that engineering and economic limitations may prevent repowering from becoming cost-effective relative to the efficient new combined cycle option in my market price analysis. Some of the reasons are as follows.

First, repowering projects based on either an existing CT (as in Mr. Falk's example) or an existing steam turbine will not be able to achieve the same efficiency as the new CC units I have assumed. Second, repowering entails capital expenditures for many of the same components (e.g. combustion turbines, heat recovery steam generator, installation and retrofit costs, development costs) as would be required for a new combined cycle unit. Third, repowering requires that new components be fit into the plant configuration and layout of an existing generating unit. There are incremental costs to do this, and some units will not be suitable for this reason. Similarly, Dr. Jones and I have based our market price analyses on the cost of large CC units with significant scale economies that would not be achievable in the repowering of a many existing unit. In summary, it is reasonable to expect that generation owners and developers will take a hard look at repowering options, but not reasonable to expect that repowering options will be cost-effective on a large scale that would lower the market price analyses of Dr. Jones or myself.

In a similar vein, the Commission should disregard Dr. Jones' misleading suggestion (page 72) that savings of 10 to 15 percent may be achievable by converting a CT into a CC. I have assumed the least-cost project approach, in which the project is designed and constructed as a CC from the start. The staging of a new CC project (i.e., construct the CT first, and add the heat recovery steam generator, steam turbine generator and other components later) would entail greater financing, engineering, and construction costs, along with additional outage time to implement the combined cycle phase.

Q. PLEASE COMMENT ON THE REPRESENTATION OF ENERGY PRICE BIDS IN DR. JONES' MARKET PRICE ANALYSIS.

A. Dr. Jones conducted his market price analysis using EGEAS, a commercially available production costing program. Generating units are represented in the EGEAS model based on their incremental heatrate curves. That is, a generating unit's energy bid is represented as its incremental cost to increase output from the various output levels the unit is dispatched at in his analysis. In my initial testimony I raised the concern that when operating at part load output levels (which tend to be less efficient than full load), a bidder would need to bid its output at a higher price in order to recover its variable costs. Dr. Jones recognizes this situation:

> "In a competitive market, generation owners will bid the maximum of their incremental costs and their average variable costs...for each block of their generation unit." (Page 62, line 12)

Acknowledging that the incremental heatrate approach in EGEAS understates generators' likely bid prices at times, Dr. Jones tested an alternative approach by representing generating unit bids at their average heatrates. According to Dr. Jones, the result of this case was slightly higher market-clearing energy prices, lowering his estimate of PP&L stranded costs by about $37 million. While Dr. Jones' alternative analysis does not quantify (as I have) the impact of energy bids in excess of full load average cost, and it does not appear to incorporate the additional (albeit limited) effect of startup costs on market price, the Commission should at a minimum evaluate PP&L's stranded cost analysis based on Dr. Jones' alternative analysis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

43505

PJM MARKET PRICE ESTIMATE
Fall 1996 DRI Fuel Price Forecast

YEAR	ENERGY $/MWh ALL-HOURS	CAPACITY $/KW-YR	TOTAL $/MWh ALL-HOURS
1999	21.30	19.73	23.55
2000	22.73	30.43	26.21
2001	24.15	41.67	28.90
2002	25.54	43.12	30.47
2003	27.47	44.20	32.52
2004	28.99	45.66	34.20
2005	31.75	47.12	37.13
2006	33.56	48.91	39.14
2007	35.48	50.38	41.23
2008	37.07	52.19	43.03
2009	38.75	54.02	44.91
2010	40.96	56.18	47.37
2011	42.83	57.98	49.45
2012	44.71	60.12	51.57
2013	47.37	62.29	54.48
2014	49.15	64.47	56.51
2015	50.81	66.66	58.42

DRI 96 Fuel Prices

YEAR	PP&L WEIGHTED GENERATION PRICE, $/MWH
1999	25.70
2000	29.26
2001	32.82
2002	34.58
2003	36.63
2004	38.13
2005	41.39
2006	43.67
2007	45.48
2008	47.66
2009	49.57
2010	52.15
2011	54.46
2012	56.79
2013	59.90
2014	62.09
2015	64.35

PJM MARKET PRICE ESTIMATE
Spring 1997 DRI Fuel Price Forecast

YEAR	ENERGY $/MWh ALL-HOURS	CAPACITY $/KW-YR	TOTAL $/MWh ALL-HOURS
1999	21.64	19.72	23.89
2000	22.62	30.36	26.09
2001	24.24	41.66	28.99
2002	25.51	42.84	30.40
2003	27.08	44.13	32.12
2004	28.24	45.57	33.44
2005	29.89	47.08	35.27
2006	32.18	48.74	37.75
2007	33.64	50.44	39.40
2008	35.53	52.25	41.50
2009	36.48	54.13	42.66
2010	38.33	56.04	44.73
2011	40.00	58.03	46.63
2012	41.72	60.10	48.58
2013	43.54	62.24	50.65
2014	45.32	64.45	52.68
2015	47.37	66.78	54.99

DRI 97 Fuel Prices

YEAR	PP&L WEIGHTED GENERATION PRICE, $/MWH
1999	26.20
2000	29.31
2001	33.24
2002	34.78
2003	36.54
2004	37.68
2005	39.88
2006	42.53
2007	43.99
2008	46.50
2009	47.76
2010	49.91
2011	52.08
2012	54.26
2013	56.58
2014	58.75
2015	61.46

New Combined Cycle Non-Fuel Cost Assumptions

Unit Characteristics | **Source**

Nominal Size (MW) Summer MW (90 degrees F)	500 MW 450 MW	Based on data from Gas Turbine World 1996 Handbook 1993 EPRI TAG
Primary Fuel	Natural Gas	
HHV Heat Rate at ISO	6,700 Btu/kWh	Based on data from GTW 1996 Handbook

Components of Capital Cost | **Source**

Turnkey Capital Costs at ISO (1996$/kW)	425 $/kW	Low end based on data from GTW 1996 Handbook
Switchgear Cost	25 $/kW	Obtained from GE by PHB; PECO mkt. price testimony
Gas Pipeline Cost (5 miles)	4 $/kW	Oil and Gas Journal, 25 Nov. 1996 *
Electrical Transmission (10 miles)	4 $/kW	Obtained from GE by PHB; PECO mkt. price testimony *
Land Cost (100 acres)	0.1 $/kW	1993 EPRI TAG *
Infrastructure	9 $/kW	PHB estimate; PECO mkt. price testimony *
More Complex CC Design	0 $/kW	
SCR for NOx Control	0 $/kW	
Decommissioning	0 $/kW	
Plant Development / Siting	10 $/kW	LCA estimate
Interest During Construction (5%)	19 $/kW	LCA estimate
All-In Costs (1996$/kW)	**496 $/kW**	
All-In Costs @ Summer Rating (1996$/kW)	**550 $/kW**	

* Note that these per kW costs are based on installation at a 1125 MW station.

New Combustion Turbine Non-Fuel Cost Assumptions

Plant Characteristics		Source
Nominal Size (MW) Summer MW (90 degrees F)	250 MW 220 MW	Based on data from Gas Turbine World 1996 Handbook 1993 EPRI TAG
Primary Fuel Secondary Fuel	Natural Gas FO2	
HHV Heat Rate at ISO	11,000 Btu/kWh	Based on data from GTW 1996 Handbook

Components of Capital Cost		Source
Turnkey Capital Costs at ISO (1996$/kW)	185 $/kW	Low end based on data from GTW 1996 Handbook
Delivery Charges (3%)	6 $/kW	
Step-up Transformer & Switchgear Cost	40 $/kW	Obtained from GE by PHB; PECO mkt. price testimony
Gas Pipeline Costs	0 $/kW	
Distillate Tank	2 $/kW	1995 Means Site Work and Landscape Cost data *
Electrical Transmission (10 miles)	5 $/kW	Obtained from GE by PHB; PECO mkt. price testimony *
Land Cost (100 acres)	0.1 $/kW	1993 EPRI TAG *
Infrastructure	5 $/kW	PHB estimate; PECO mkt. price testimony *
Plant Development / Siting	8 $/kW	LCA estimate
Interest During Construction (2.5%)	4 $/kW	LCA estimate
All-in Costs (1996$/kW) **All-in Costs @ Summer Rating (1996$/kW)**	**255 $/kW** **290 $/kW**	

* Note that these per kW costs are based on installation at a 1000 MW station.