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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

Direct Testimony and Exhibits of

ROBERT D. KNECHT

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

Date Served: JuLY 2, 1997

Date Submitted for the Record: ______________

DIRECT TESTIMONY OF ROBERT D. KNECHT

INTRODUCTION AND OVERVIEW OF CONCLUSIONS

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal and the Treasurer of Industrial Economics, Incorporated (IEc), an economic consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. I specialize in the economic analysis of basic industries, particularly the mining, metals and energy industries. As part of my consulting practice, I have prepared analyses and expert testimony in the field of regulatory economics, in various U.S. and Canadian jurisdictions. I have also participated in a number of international industry restructuring studies, in the mining and metals industries. I obtained a B.S degree in Economics from the Massachusetts Institute of Technology in 1978, and an M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982. I am appearing in these proceedings on behalf of the Pennsylvania Office of the Small Business Advocate (OSBA). My résumé and schedule of appearances in regulatory proceedings is attached as Exhibit RDK-1.

Q. Please describe your assignment.

A. I was retained by the Pennsylvania Office of Small Business Advocate (OSBA) to review the filing and interrogatory responses of Pennsylvania Power & Light Company (PP&L) relating to its restructuring plan, and to determine whether small business customers are treated fairly and equitably in that plan. I have focused my efforts on evaluating the general methodology proposed, the economic implications inherent in the restructuring plan, the proposed discount rate for stranded cost determination, market price forecasting, transition policies relating to the small business classes, and rate design issues.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1 ***PP&L's overall methodology, the "residual CTC" or "bottom-up" approach, for determining CTC tariff levels is generally reasonable.*** PP&L's method for developing its CTC begins with existing rates, backs out allocated transmission and distribution costs, and subtracts the forecasted market electricity prices. This approach therefore produces a "residual CTC." As forecast market prices rise over time, the CTC perforce declines. Because PP&L proposes this "residual CTC" method, the net present value (NPV) of CTC revenues will not necessarily match the NPV of stranded costs. In fact, PP&L's filing indicates that it will recover only \$4.2 billion in CTC revenues of \$4.6 billion (after mitigation) in stranded costs, on a present value basis. Of course, this method and this case are very different from a traditional utility rate case. The various parameters that are developed in this procedure have implications for the amount of competition in PP&L's service territory and the magnitude of the CTC. These implications are explored briefly in this testimony.

2 If the Commission determines that PP&L's stranded costs are lower (on an NPV basis) than the CTC recoveries determined through PP&L's residual CTC procedure, it will be necessary to devise a method for assigning that net amount to ratepayers. ***In that event, I recommend that a proportional scaleback of the approved CTC charges be adopted to limit CTC revenues.***

3 In making the net present value calculation for stranded costs and CTC revenues, where stranded costs are computed over a long time period but CTC revenues are earned only over a relatively short period, the choice of a discount rate to reflect the time value of money is critical. PP&L elects to use an after-tax weighted average cost of capital measure for discounting both CTC revenues and stranded costs. However, PP&L presents no theoretical justification for the use of this discount rate. ***My testimony presents an algebraic proof that the appropriate discount rate for computing the NPV of CTC revenues and stranded costs is the after-tax return on equity.*** This conclusion follows mathematically from the following propositions:

- The after-tax returns to shareholders under deregulation, including those revenues earned through the CTC, should be no greater than those that would have been earned under regulation.

- After-tax returns to shareholders should be discounted at the after-tax cost of equity.

In PP&L's case, using a higher discount rate reduces the disparity between CTC revenues and stranded costs. (This directional result may be different at other utilities.) All else equal, use of PP&L's after-tax cost of equity decreases the differential from some $500 million to less than $100 million.[1]

4 To determine stranded costs and CTC rates, PP&L has produced a conservative forecast of electricity prices. In developing that forecast, many of PP&L's assumptions, while not unreasonable by themselves, tend to be on the conservative side. In aggregate, these assumptions produce a price forecast that is unduly conservative. ***For stranded cost determination, the Commission should require PP&L to utilize an electricity price forecast that reflects less conservative assumptions.***

5 PP&L's proposal for a 'true-up' mechanism for CTC revenues has advantages of simplicity, rate stability and predictability, and equity. ***However, I recommend against a guarantee for an extension of the transition period in the event of CTC revenue under-recovery.*** I propose that such a determination be made by the Commission near the end of the transition period. I also recommend that the true-up mechanism be evaluated on a net present value basis, rather than a strictly nominal basis as envisioned by PP&L.

6 PP&L proposes a customized rate design (CRD) for structuring the CTC tariff, in which approximately half of the CTC revenues are recovered from a customer-specific customer charge, determined from each customer's 1996 electricity consumption level. As proposed, the CRD is optional for residential customers, and mandatory for all other customers. As recovery of stranded costs is justified primarily on fairness grounds, it is ironic that PP&L defends its rate design proposal primarily on economic efficiency grounds. While its economic efficiency argument has merit, particularly for customers considering increase consumption levels, PP&L has neglected equity considerations and downside risks, particularly with respect to small business customers. ***In light***

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[1] As discussed further in the text, my calculations show a somewhat higher present value under-recovery of stranded costs under PP&L's proposal (approximately $500 million v. $400 million) than from its own reported levels.

of the nature of the CTC, consideration of the high rates of return and high stranded cost recovery levels provided by the small business classes, I recommend that GS-1 and GS-3 customers be offered the same option for CRD as residential customers.

7 Although it is revenue neutral, PP&L's proposed implementation of the CTC for the GS-1 rate class will cause intra-class revenue shifts and will produce skewed incentives. PP&L's CTC proposal contains *negative* CTC "excess demand" charges, which can result in negative CTC revenues from larger, low load factor GS-1 customers. Also, PP&L proposes an excess demand charge for its market rates, effectively discouraging smaller customers from availing themselves of alternative suppliers. Finally, PP&L proposes a flat energy tariff for transmission/distribution service to both the GS-1 and GS-3 classes, implying an eventual elimination of the existing block structure for delivery service. ***In this testimony, I propose different rate design schemes for the GS-1 and GS-3 classes that reduce these potential problems and maintain existing block structures in the delivery charges.***

8 PP&L interprets the legislated rate cap provisions as mandating continuation of the EDI/IDI rate credit programs through the transition period, that otherwise were scheduled to be phased out. However, PP&L proposes to apply those credits only to utility generation service from PP&L's electric delivery group. This is a compound problem, hinging on a legal conclusion. ***If EDI/IDI credits can lawfully be phased out under the rate cap provisions of the Act, I recommend that they be phased out.*** Customers who have benefitted from those discounts have made decisions based on the expectation that they will be phased out. There is therefore neither an economic development nor an equity reason to continue to provide the rate discounts. However, if the legal conclusion is that the discounts must be maintained through the transition period, PP&L's proposed method serves only to discourage entry and competition in its service territory. ***To avoid discouraging entry and competition, I recommend that, if the EDI/IDI credits are deemed to be mandatory, that they be made available to all customers who are eligible for the credits, regardless of their choice of generator.***

9 For the transition period, PP&L must take great care in the phase-in rules for general service customers. The GS classes consist of a wide variety of very customers with diverse load patterns, some of whom compete with one another. ***As part of its transition plan, PP&L should develop rules for assuring that some customers do not gain competitive advantage over other customers, because of differential access to competing generation suppliers. PP&L should also distinguish between the various commercial rate classes***

in its phase-in process, to ensure that large commercial customers do not dominate the customer group entitled to market access.

These conclusions are addressed in detail below in the corresponding sections. Analytical schedules are presented in Exhibit RDK-2, and supporting interrogatory responses are attached as Exhibit RDK-3. Exhibit RDK-4 contains copies of recent news reports regarding nuclear plant economics.

ANALYSIS OF PP&L RESTRUCTURING PROPOSAL

1 Overview of PP&L's Method for CTC Determination

Q. Please summarize PP&L's approach for determining the CTC.

A. The Electricity Generation Customer Choice and Competition Act (the Act) provides for the development of a non-bypassable competitive transition charge (CTC) that will allow utilities to recover stranded costs. Stranded costs are explicitly defined in the Act as:

> *"An electric utility's known and measurable net electric generation costs, determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility. . . ."* (§2803)

To calculate its stranded costs, PP&L interprets this definition as the net present value of the difference in forecast revenue streams between those which would be allowed under regulation and those that are expected to be earned under competition. Forecast revenues that are expected to be earned under competition are developed from Dr. Scott Jones' price and generation forecasts, developed using the EGEAS model. Revenues that would be earned under continued regulation are determined using a revenue requirement approach as detailed by Mr. Schadt in Exhibit JRS-1. In effect, all generation-related costs that would be allowable costs under traditional regulation (O&M, depreciation, taxes and return on capital) are used to develop the regulated revenue stream. These cash flows are forecast for the life of the existing assets, and discounted to (approximately) 1 January 1999 using an after-tax weighted average cost of capital.[2] This calculation produces a stranded cost value of $4.6 billion.

Although the Act allows regulated utilities to develop a CTC to recover stranded costs, it also imposes a cap on rates, and limits the period over which the CTC can be charged. Rates for transmission/distribution (T&D) service are capped from the effective date of the Act (1 January 1997) through 30 June 2001 (54 months), while generation service rates are capped through 2005 (9 years). The CTC may only be charged for the nine-year period in which the generation rate cap is in effect. Within these constraints, PP&L develops its CTC using a "residual CTC" approach. Class-specific CTC's are calculated by taking existing rates and subtracting the allocated T&D costs and deducting forecast class-specific market prices.[3] Thus, as forecast market prices rise in the future, the CTC

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[2] 1 January 1999 is used for the NPV date since it represents the beginning of the phase-in period to competition. Competition is phased in over three years.

[3] Allocated transmission and distribution costs are determined using the historical cost allocation study from PP&L's compliance filing for its last base rates proceeding (for the future test year ended 30 September 1995, filed on 5 October 1995). Mr. Kleha then unbundles these costs into generation, transmission and distribution components. To be consistent with the Act's mandate that restructuring not

declines.[4]

Because revenues are constrained by the rate cap, and because of the "residual CTC" approach, there is no arithmetic reason why CTC revenues and stranded costs will balance. And, in fact, when PP&L's reported CTC revenues are discounted at the after-tax weighted average cost of capital,[5] it produces a CTC present value at 1 January 1999 of $4.1 billion, or some $500 million less than the stranded cost estimate.[6]

Q. Do you agree with this overall approach?

A. Overall, I believe that the PP&L approach is reasonable. Because the CTC is determined as the residual, the method puts all classes on an equal basis with respect to the attractiveness of purchasing generation services from non-PP&L suppliers. In effect, in each class, outside suppliers will compete with PP&L's forecast of market prices. In addition, PP&L's approach eliminates the need to develop a cost allocation method for stranded costs, since they are determined as the residual. However, this method makes

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impact relative cost recovery amongst the classes, allocated costs are determined using the actual rate of return exhibited by the class in those proceedings. Thus, the "costs" assigned to the GS-1 and GS-3 classes employ rates of return of 15.7 percent and 11.4 percent respectively, compared to the PP&L average of 9.5 percent. In each year, the CTC is calculated as the 1995 allocated costs for generation less the forecast market prices for energy and capacity for that year.

[4] Note that the CTC will be specified in the extant proceedings for every year, and will not change if market prices deviate from forecast.

[5] PP&L's choice of the after-tax weighted average cost of capital as the discount rate for NPV calculations is addressed in Section 3.

[6] Mr. Krall reports a present value of $4.210 billion for CTC revenues (PP&L Statement No. 10, page 10, lines 13-15). I am unable to replicate that figure using the CTC revenues reported in OCA-III-39 and the discounting methodology used by Mr. Schadt in Exhibit JRS-1. In OSBA-I-36, Mr. Schadt reports a net present value of CTC revenues of "approximately $4 billion." In addition, the revenue calculations in OCA-III-39 for the GS-3 class appear to use incorrect energy consumption levels for computing CTC revenues, thereby slightly understating them. I hope to resolve these issues as discovery proceeds.

the market price forecast for electricity a critical issue for determining how competitive the industry will be during the transition period.

Q. **Do you agree with Professor Kalt that "if market prices rise above the level that was used to estimate stranded costs and to set the CTC, the Company may charge no more than the generation-related rate cap?" (PP&L Statement No. 1, page 16)**

A. Professor Kalt's statement is true only for the transition period, and it is a little misleading. If market prices increase above forecasted levels during the transition period, the economic impact on PP&L depends on the underlying cause of that increase. If the increase is caused by rising natural gas prices or unexpected plant closures by PJM competitors, PP&L is no worse off on the cost side than if prices do not rise. However, under-forecasted market prices give rise to below-market rates for utility generation service, under PP&L's residual CTC methodology. If utility generation service is priced below market rates, PP&L will maintain a dominant market position in its service territory throughout the transition period, by effectively locking in its existing customers at utility generation service rates. Moreover, if market prices rise above the forecast levels beyond the transition period, PP&L shareholders will be able to earn profits greater than those they would have earned under competition. Thus, PP&L shareholders have the potential to over-recover or under-recover stranded costs, under the rate cap provisions of the Act.

Q. **Please review briefly the implications of changing various assumptions within PP&L's methodology. Beginning with stranded costs, what are the implications of changing PP&L's forecasts of the costs that would be allowable under a traditional regulatory scheme?**

A. In PP&L's scheme, unless substantive changes are made in the cost forecast or other parameters, there would be no impact on either the CTC or the competitiveness of the markets in the transition period. Increasing PP&L's cost forecast would simply increase the amount of expected stranded costs that are not recovered. Modestly decreasing PP&L's cost forecast would only reduce the magnitude of under-recovery, with no impact on CTC's. Unless costs are reduced by more than $500 million in present value terms (all other factors being equal), decreasing the cost forecast will have no impact on the CTC or the competitiveness of the transition market.

Q. What are the implications of changing PP&L's electricity market price forecast?

A. The implications depend both on the factors that drive market electricity prices, and on the time period which is affected. If I put aside fuel price implications for a moment (and return to them below), PP&L has incentives to utilize a "conservative" market price forecast for electricity. First, in the transition period (1999 to 2005), a low forecast of market prices improves the competitive position of PP&L vis-a-vis other generation suppliers. (Note that in the transition period, if PP&L's market price forecast were adjusted upward, both its stranded cost claim and its CTC revenues would decline relative to the existing proposal.) After the transition period, a low market price forecast increases PP&L's stranded cost claim. Most intervenors (customers and potential competitors) have the reverse incentives, namely for more aggressive price forecasts. Higher forecast market prices in the transition period would reduce CTC charges and make alternative generation suppliers more competitive. Similarly, higher post-transition period price forecasts will reduce the stranded cost claim.

Q. Please turn back to fuel price forecasts. What are the implications for higher natural gas price forecasts?

A. If PP&L's natural gas price forecasts are increased, particularly in the period when new capacity is constructed, electricity prices will be higher. Because PP&L has little existing gas-fired capacity, its forecast costs will not increase proportionally to forecast electricity revenues, if higher gas prices are forecast. Its unregulated profits will be higher than forecast (or losses will be lower), and its stranded cost claim will be reduced.

Q. Are the implications the same for coal price forecasts?

A. For coal, the implications may very well be the reverse of natural gas. If coal prices forecasts are increased, PP&L's forecasted costs will rise. While electricity prices will also rise, particularly during low demand periods, it is likely that the cost effect will outweigh the price effect, particularly in future years when prices are determined mainly by gas-fired units.

Q. What do you conclude from this review of implications?

A. Computing stranded costs involves making a huge number of assumptions. These assumptions will certainly affect the amount of competition that will take place in PP&L's service territory in the transition period, and could very well affect the magnitude of overall CTC revenues. Thus, the assumptions need to be carefully scrutinized. In addition, sensitivity analyses can provide valuable insights into the implications of differing assumptions.

2 Allocation of Stranded Cost Reduction

Q. Mr. Knecht, PP&L's proposal shows expected CTC revenues of $4.2 billion in net present value, and expected stranded costs of $4.6 billion. Suppose that the Commission determines that PP&L's forecast stranded costs are less, in net present value terms, than the forecast residual CTC revenues. To whom should these excess revenues be assigned?

A. These excess revenues should be assigned to ratepayers, and should not accrue to utility shareholders. Otherwise, utility shareholders can expect higher returns under deregulation than under competition, a result that appears to violate the spirit of the Act. Thus, if PP&L's allowed stranded cost claim falls below the forecast CTC revenues, the proposed CTC charges and revenues should be reduced in some way.

Q. What approaches have you considered for reducing CTC revenues, such that they not exceed stranded costs?

A. I have considered two alternatives, each with its own appeal. The first is a shortening of the period of CTC recovery. The second is an across-the-board reduction in PP&L's proposed CTC charges, for all years of the transition period.

Q. Can you describe the option of shortening the period of recovery?

A. Yes. Simply, the CTC would be imposed as proposed by PP&L, but it would end prior to 31 December 2005. A specific final date for CTC recoveries can be developed now, based on the magnitude of the allowed stranded cost claim, the approved CTC charges, and forecast deliveries.

Q. Can you describe the option of an across-the-board reduction in CTC charges?

A. Yes. This option would involve taking PP&L's proposal and reducing every CTC charge by the ratio of approved stranded costs to base case stranded revenues. For example, if the Commission determines that stranded costs are $4.0 billion, while stranded revenues are $4.2 billion (all in net present value terms), each of PP&L's proposed CTC charges would be multiplied by the ratio of 4.0 to 4.2. Since the calculation of stranded costs and CTC revenues begins in 1999, this proposal would effectively reduce fully bundled rates on 1 January 1999.

Q. What are the relative advantages of the two methods?

A. Both methods are reasonable. The former would eliminate the distortions caused by the CTC sooner, while the latter would impose less of a distortion over a longer period of time. My recommendation is for the across-the-board reduction. First, this approach is more gradual, since the drop-off in rates at the end of the transition period will be less severe. Second, such an approach would provide immediate and tangible benefits to existing ratepayers from deregulation, in the form of lower fully bundled rates.

Q. If the across-the-board reduction in CTC charges is adopted, should PP&L be required to increase its posted utility generation rates, maintaining fully bundled rates at their existing level?

A. Although such a proposal would encourage entry and competition in PP&L's service territory, I would not advocate such a change for a couple of reasons. First, raising the posted utility generation rates above those proposed would increase them above forecast market levels, putting PP&L utility service at a competitive disadvantage (if the forecast is accurate). Customers who choose utility backstop service will pay a premium. (In effect, it might be seen as a tax on ignorance.) Second, since competition is only phased in over a three year period, those customers who do not have the opportunity to select an alternative supplier in the interim will be unfairly penalized.

3 Discount Rates for Stranded Costs

Q. Please detail what you mean by "discount rates" and explain why it is relevant in these proceedings.

A. As I described in Section 1, the Act dictates that stranded costs must be computed on a net present value basis. Net present value analysis involves adjusting or "discounting" future revenue and cost streams to adjust for the time value of money. While PP&L's methodology includes an enormous number of assumptions, this section of my testimony addresses only the issue of the appropriate discount rate to use. The discount rate is a measure of the cost of capital, and it is used to adjust future cash flows to "present value." Because there are timing differences between the period specified for determining what stranded costs are (1999 to 2045) and the period of stranded cost recovery (1999 to 2005), the discount rate is a significant consideration in this case. A summary of PP&L's NPV calculation of CTC revenues and stranded costs is shown in Exhibit RDK-1, Schedule 1.[7]

[7] The NPV for stranded costs shown in Exhibit RDK-2 Schedule 1 are slightly different than those reported by Mr. Schadt in Exhibit JRS-1. Mr. Schadt has employed a monthly NPV calculation while Exhibit RDK-2 Schedule 1 employs an annual method. Both methods discount stranded costs to approximately 1 January 1999. Consistent application of either method to CTC revenues and stranded costs produces an under-recovery figure of approximately $500 million, when the after-tax weighted average cost of capital is used as the discount rate. (My method produces a slightly larger under-recovery figure.) As noted earlier, I am unable to replicate Mr. Krall's calculation of the NPV of CTC revenues,

Q. Please describe generally how discount rates are determined, for preparing net present value calculations.

In preparing net present value calculations, the financial analyst employs a discount rate that reflects the riskiness of the cash flows. Cash flow analyses are typically delimited along two dimensions: "asset-related" v. "equity-related" cash flows, and pre-tax v. after-tax cash flows.

Cash flows that are "asset-related" are cash flows derived excluding interest costs and debt repayments. In the most simple form, asset-related cash flows are cash revenues minus cash operating costs minus capital expenditures.[8] Because no fixed debt payments are specified, asset cash flows are less risky than equity cash flows. They are often discounted using a "weighted average cost of capital," which reflects the cost of debt, the cost of equity, and the tax deductibility of interest payments. "Equity-related" cash flows, on the other hand, are calculated net of interest and debt repayment obligations -- in effect, they are cash flows to the equity holder. Equity cash flows are therefore discounted at the cost of equity.

Similarly, pre-tax cash flows do not account for cash tax costs, while after-tax cash flows have cash taxes deducted before discounting. Pre-tax cash flows are typically discounted using a pre-tax discount rate, while after-tax cash flows are discounted using

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so I rely on the values presented in Exhibit RDK-2 Schedule 1.

[8] In practice, cash flow analyses are more complex, and include changes in working capital, careful segregation of cash and non-cash expenses, and a variety of other non-expensed cash flows.

an after-tax discount rate.[9]

Q. How does the traditional utility cost of capital, namely PP&L's 9.46%, relate to these considerations?

A. To my knowledge, the "cost of capital" or "return" measure used in utilities' rate proceedings is a unique concept -- it is neither pre-tax nor after-tax. As such, it has no relevance in a discounted cash flow analysis. Algebraically, the utility cost of capital measure is defined in Equation (1) as:

$$(1) \qquad Ru = Rd * D\% + Re * E\%$$

where:

Ru = utility cost of capital
Rd = utility cost of debt
Re = utility cost of equity
D% = debt share of capitalization
E% = equity share of capitalization

Note that the formula in Equation 1 does not recognize that interest costs are tax deductible for income tax purposes while returns to equity holders are not. Because tax considerations are omitted from this formula, it is necessary to "gross up" revenue requirement impacts for changes in the allowed return on equity.

Q. What discount rate is PP&L proposing to use in its stranded cost claim?

A. PP&L applies an after-tax weighted average cost of capital to both its stranded cost and CTC revenue streams to produce the $4.6 billion and $4.2 billion figures respectively.

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[9] In general, after-tax analyses are preferable to pre-tax analyses. Except in very narrow circumstances, discounting pre-tax cash flows with a pre-tax discount rate will usually not produce the same NPV as discounting the after-tax cash flows with an after-tax rate. Since taxes are an unavoidable fact of life, including taxes explicitly in the analysis is the preferred approach.

The after-tax weighted average cost of capital is depicted algebraically in Equation 2:

$$(2) \qquad Rwacc = (1 - \mathrm{T}) * Rd * D\% \; + \; Re * E\%$$

where:

Rwacc = *after-tax weighted average cost of capital*
T = *marginal income tax rate*

PP&L witness Schadt argues that the after-tax weighted average cost of capital is the appropriate measure, but he provides no insight into why the difference between two forecast revenue streams should be considered pre-tax or after-tax, or whether they are related to returns to equity holders or returns to all financing sources.[10]

Q. **How have you analyzed this problem?**

A. I begin with first principles. I believe that it is the spirit of the Act is that the expected return to shareholders through competition and the CTC should be no greater than the expected return to shareholders under regulated conditions.[11] Under regulation, the after-tax return to the shareholders is the allowed return on equity applied to the equity share of rate base. Under competition/CTC, the return to equity holders will be market revenues plus CTC revenues less all operating, interest, and tax costs. *Because these returns are after-tax returns to equity holders, the appropriate discount rate for both sides of the equation is the after-tax cost of equity.*[12]

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[10] See OSBA-I-35.

[11] If the rate cap did not exist, or if the rate cap does not constrain full recovery of stranded costs, then the expected return to shareholders should be the same under both scenarios.

[12] PP&L agrees with this conclusion in OSBA-I-35.

Q. In its response to OSBA-I-35, PP&L apparently does not agree with your assertion that the spirit of the Act is that "the expected net present value of after-tax income to PP&L's shareholders earned by pricing at market rates plus a CTC should be no greater than the expected net present value of after-tax income that PP&L's shareholders would have earned under regulation." Can you respond to PP&L's concerns?

A. Yes. PP&L raises four concerns, only one of which is relevant. PP&L indicates that cash flows, not income, are the appropriate measure, an assertion with which I agree. PP&L then states, ". . . *in theory, the sum of the total after-tax cash flows derived by PP&L from the market price of energy sold from PP&L's facilities should equal the total after-tax cash flows that would have been realized under continuing cost-of-service regulation (both stated as their net present value as of January 1, 1999) . . .*" I agree also with this assertion, except that a rate cap may preclude full recovery of stranded costs during the transition period. PP&L then raises three "reality" objections to this theoretical principle.

Q. Are PP&L's objections relevant?

A. No. PP&L's first objection is that the rate cap may preclude PP&L from recovering its full stranded costs. I agree. That is why the principle, as stated in the interrogatory, indicates that expected earnings (cash flow) under regulation plus CTC should be *"no greater than"* expected earnings under cost-of-service regulation. PP&L's second and third objections relate to future variances in market prices and costs from the current forecast levels. Mr. Moul and Mr. Schadt apparently misinterpreted the term *"expected net present value"* used in the interrogatory. Expected net present value means the net present value determined from current expectations, namely the price and cost forecasts developed by PP&L and modified or approved by the Commission. As PP&L correctly observes, there is no true-up mechanism for variances in stranded costs from expectations. However, this fact does not mean that a CTC should be set such that the expected returns under deregulation plus CTC should exceed expected returns under regulation.

Q. Can you model the principles that you have expressed in mathematical form?

A. Yes. For the purposes of the following discussion, I am going to set aside rate cap considerations, for further discussion below. For now, I assume that CTCs can be set such that they fully recover stranded costs, and that equity holders are economically neutral between regulation and deregulation plus CTC. This principle can be expressed algebraically as shown in Equation (3).[13]

$$(3)\qquad \sum_{t=1999}^{2045} \frac{Re * E\% * RB_t}{(1+Re)^{(t-1998.5)}} = \sum_{t=1999}^{2045} \frac{(1-T)*(MKTREV_t + CTC_t - O\&M_t - Rd*D\%*RB_t)}{(1+Re)^{(t-1998.5)}}$$

where:

$MKTREV$ = *revenues earned under competition*
CTC = *revenues from CTC charges* (1999 - 2005)
$O\&M_t$ = *allowable costs under regulation excluding income taxes*
RB_t = *rate base*

Q. Can you describe Equation (3) in words?

A. In Equation (3), the left hand side represents the after-tax return to equity holders under

[13] Note that this analysis measures return on an income basis. This methodology is easily generalized to a cash flow basis. The primary differences between income and cash flow are depreciation and capital expenditures. Since these cash flows are the same under the regulated and unregulated scenarios (both scenarios assume continued operation of existing facilities), they would appear as equal values on either side of Equation (3), and can be algebraically eliminated. Thus, the cash flow version of this proof produces the same result for the applicable discount rate.

traditional regulation, namely that they receive the allowed after-tax return on equity for the equity share of capitalization. The right hand side shows the after-tax return under the transition to competition and beyond. For determining the return under deregulation plus CTC, revenues are market revenues plus CTC revenues. From that, all O&M and tax-deductible interest payments are subtracted, and the net income is taxed. Both streams are discounted at the after-tax cost of equity, because both streams are after-tax returns to equity holders.

Q. **What is the next step?**

A. With a little algebraic substitution, I can rearrange terms to isolate CTC revenues, thereby producing Equation (4):

$$\sum_{t=1999}^{2045} \frac{CTC_t}{(1+Re)^{(t-1998.5)}} = \sum_{t=1999}^{2045} \frac{Re*E\%*RB_t/(1-T)}{(1+Re)^{(t-1998.5)}} + \sum_{t=1999}^{2045} \frac{O\&M_t + Rd*D\%*RB_t - MKTREV_t}{(1+Re)^{(t-1998.5)}}$$

or

$$(4) \quad \sum_{t=1999}^{2045} \frac{CTC_t}{(1+Re)^{(t-1998.5)}} = \sum_{t=1999}^{2045} \frac{O\&M_t + (Rd*D\% + \frac{Re*E\%}{(1-T)})*RB_t - MKTREV_t}{(1+Re)^{(t-1998.5)}}$$

Q. **How does this help?**

A. Equation (4) solves the problem! The right hand side of Equation (3) is exactly equal to PP&L's formula for determining stranded costs, but for the difference in the discount rate. Stranded costs, as determined by Mr. Schadt, are the allowable costs under regulation, plus the cost of debt, plus the cost of equity ("grossed up" for income taxes), less the revenues that are earned under competition. Thus, when no rate cap exists, CTC revenues must be developed such that, when they are discounted at the after-tax cost of equity, they equal the present value of stranded costs, also discounted at the after-tax cost of equity. If this equality does not obtain, the principle expressed in Equation (3) is violated, and shareholders will either be better off or worse off under deregulation plus CTC than under regulation.

Q. Can you provide a numerical example of this finding?

A. Yes. Exhibit RDK-1, Schedules 2 and 3 show the effects of using the different discount rates. This example is a simple two-period model of restructuring. CTC revenues are allowed to be recovered only in Period 1, while stranded costs are incurred in both periods. The after-tax WACC is assumed to be 8 percent, and the after-tax cost of equity is 12 percent. Schedule 2 presents the results of discounting stranded costs and CTC revenues at the after-tax WACC. Under regulation, the revenue requirement is $140 in both periods, including after-tax returns to equity holders of $30 per period. Since after-tax returns to equity holders must be discounted at the after-tax cost of equity (12 percent), the NPV of the regulation scenario for equity holders is $56.79 (valued at the middle of period 1).

Stranded costs are then computed as the difference between the regulation revenue requirement and the market revenues of $100 per period, producing stranded costs of $40 per period. When discounted at the WACC of 8 percent, the NPV of stranded costs is $77.04. Since CTC revenues can only be recovered in Period 1, a CTC charge of $77.04 is specified for Period 1.

To determine the returns to equity holders in the deregulation plus CTC world, revenues from the market are added to CTC revenues, producing revenues of \$177.04 in Period 1 and \$100 in Period 2. O&M costs, debt costs and income taxes are deducted, to produce returns of \$52.22 in Period 1 and \$6.00 in Period 2. However, the net present value of these after-tax returns to equity is \$57.58, **higher** than the returns under regulation. Thus, the method proposed by PP&L, in this example, would provide a higher NPV return to equity holders under deregulation plus CTC than under continued regulation.

Q. Does using an after-tax cost of equity measure resolve this problem?

A. Yes. Exhibit RDK-1, Schedule 3 demonstrates how. Instead of discounting the two \$40 stranded cost figures at 8 percent, they are discounted at the after-tax cost of equity, 12 percent. This reduces the Period 1 CTC to \$75.71. When returns to equity holders are recomputed for the deregulation plus CTC scenario, CTC revenues are lower, income taxes are lower, and returns to equity holders are lower. The new returns, discounted at 12 percent, produce the same return of \$56.79 as computed for the regulation scenario. Thus, by determining the CTC charge using the after-tax cost of equity, shareholders are neutral between regulation and deregulation.

Q. What is the impact of incorporating the Act's rate cap into this analysis?

A. Algebraically, the problem becomes an inequality. In Equation (3), the earnings under regulation (the left-hand side) must be greater than or equal to the earnings under deregulation plus CTC (the right-hand side). In Equation (4), CTC revenues must be determined such that their net present value is less than or equal to stranded costs. For

PP&L, the net present value of the CTC revenues, as determined by the "residual CTC" method, must be less than or equal to the net present value of stranded costs, as determined by Mr. Schadt, with the critical proviso that both NPV's be developed using an after-tax cost of equity discount rate.

Q. **What happens if the CTC revenues, determined by the residual method and discounted at the after-tax cost of equity, exceed stranded costs?**

A. Then CTC revenues need to be reduced, either by shortening the recovery period or reducing the charges. I address this issue in Section 2.

Q. **Can you provide a logical explanation of the finding that the after-tax cost of equity is the appropriate discount rate?**

A. In developing its revenue streams, PP&L includes explicit consideration of interest costs, tax costs, and the tax deductibility of interest costs. By using the traditional measure of utility return (Ru), and "grossing up" for taxes, PP&L's revenue streams include all these revenue and cost streams. Thus, when cash flows reflect both taxes and interest costs, they represent after-tax, post-financing cash flows. The after-tax cost of equity is therefore the correct discount rate.

Q. **Mr. Knecht, you mentioned that discount rates should reflect the riskiness of investments. What does this analysis assume about the riskiness of after-tax equity cash flows before and after deregulation?**

A. One important assumption that is embedded in this analysis is that the risk adjusted rate of return (equity cost of capital) required by equity holders under restructuring and deregulation is the same as that under regulation. (In the algebraic formulae, this question is whether the Re shown on the left hand side of Equation (3) is the same Re as used on the right hand side.)

Q. Is this assumption reasonable?

A. I think that most industry observers would conclude that the cash flows to equity holders under full deregulation, exclusive of CTC revenues, would be riskier than under regulation, and therefore the cost of equity would likely be somewhat higher. PP&L's evidence suggests, however, that the additional risk would translate only into a very modest increase in the relevant discount rate.[14]

Q. Are there any factors that mitigate against assuming a higher equity cost of capital for cash flows under restructuring?

A. Yes. First, the Act does not explicitly indicate that utility equity holders should be compensated for assuming the additional risk. A determination must be made of whether it is in the spirit of the Act that utility investors should have expected returns under restructuring in excess of those under regulation. As the whole rationale for stranded cost recovery is one of fairness and not economics, I think this determination should be made by the Commission.

Q. You spoke of other reasons. Are there risk reasons why the discount rate for future cash flows should be higher?

Yes. The restructuring cash flows include relatively low-risk CTC revenues, which will substantially reduce the riskiness of the cash flows during the restructuring period. In

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[14] For example, Dr. Jones uses a 12.5 percent figure for after-tax cost of equity for unregulated power plants, compared to Dr. Moul's figure of 12.5 percent for the cost of equity to PP&L, and PP&L's own use of 11.5 percent.

fact, the CTC revenues are likely to be of lower risk than typical utility revenues for three reasons. First, PP&L's CRD rate design for the CTC will reduce riskiness, by making revenues less dependent on demand that is sensitive to weather and economic activity.[15] Second, under PP&L's "true-up" proposal, risk of variances in the "deliveries" of electric power to customers is eliminated by expanding or contracting the period of CTC recovery. Third, PP&L may further reduce the risk to its equity holders by utilizing the securitization provisions of the Act.

Q. What, then, is your conclusion regarding the use of a different after-tax cost of equity for deregulation plus CTC cash flows?

A. Since the higher risk of market cash flows is offset by the lower risk of CTC or ITC cash flows, I believe that use of the same discount rate for both returns to equity holders is reasonable. Moreover, since PP&L uses the same discount rate for CTC revenues and stranded costs, it implicitly agrees.

Q. What are the implications of using the after-tax cost of equity on PP&L's stranded cost and CTC revenue calculations?

A. In PP&L's case, the implications are significant. Using the after-tax weighted average cost of capital method, the under-recovery is approximately $500 million. Using the after-tax cost of equity as the discount rate, the present value of the under-recovery falls to less than $100 million. These calculations are shown in Exhibit RDK-2, Schedule 1.

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[15] Dr. Tierney testifies: *"Pricing electricity service more closely to marginal costs affords benefits not only to consumers, but also to PP&L. Shifting some of the competitive transition charges into fixed charges reduces the impact of weather and other factors affecting demand on CTC collection, and therefore reduces the degree of revenue risk to PP&L."* (PP&L Statement No. 9, page 22, lines 9-13)

Q. Generically, what are the implications for utilities of using an after-tax cost of equity as a discount rate, rather than the lower after-tax weighted average cost of capital?

A. There are no generic implications -- use of a higher discount rate will reduce both stranded costs and CTC revenues, but there is no uniform answer about the difference between the two. For utilities that use the PP&L "residual CTC" method, use of a higher discount rate could increase or decrease the recovery rate of stranded costs. For example, if PP&L's claim excluded nuclear stranded costs and revenues, increasing the discount rate would increase the recovery rate for stranded costs. Use of a higher discount rate is not an issue that will uniformly benefit utilities or intervenors.

Q. Can you give an example?

A. Yes. If the values in Exhibit RDK-2, Schedule 3 are modified such that stranded costs are negative in Period 2, the relative impact changes. This result is shown in Exhibit RDK-2, Schedule 4. By using the after-tax WACC for determining stranded costs in that example, the present value of returns to equity holders declines from $56.79 to $56.49. Thus, in this example, the utility shareholders are worse off using an after-tax WACC measure than the after tax cost of equity.

Q. Is it possible that some utilities would have negative stranded costs in the period after expiration of the rate cap?

A. I would not be surprised. As market prices rise and traditional revenue requirements fall as plants become more depreciated, stranded costs are more likely to become negative.

4 Electricity Market Price Forecast

Q. Does PP&L's method produce price forecasts that are consistent with price behavior in other industrial commodities?

A. Generally, no. PP&L's market price forecast ignores the highly cyclical nature of unregulated, industrial commodities. In those industries, spot commodity prices do reflect the short-run marginal cost of high cost producers in periods of excess capacity, but, in periods of tight capacity, market prices are determined by buyers' willingness to pay, not capacity replacement costs. This result obtains because, for industrial commodities produced in large manufacturing plants, new capacity can respond neither instantaneously nor optimally. In supply/demand curve terms, the supply curve becomes extremely inelastic when capacity is constrained. Prices are then determined by buyers' willingness to pay. In fact, in some industries, when supply begins to get tight, a corresponding increase in demand occurs, as "hedge buying" takes place. Customers increase their inventories to avoid being caught short if the capacity gets even tighter. This demand surge, induced by an unexpected shortage of supply, exacerbates the supply shortage, and prices rise rapidly. Of course, as supply responds or demand declines for economic reasons, the hedge buying effect is reversed, customer inventories are drawn down, and prices fall. These effects contribute to the boom-bust cycle that is common in industrial commodity markets.

Q. Since electricity cannot be inventoried, could that kind of boom-bust cycle occur in future electric markets?

A. While the energy cannot be inventoried, customers can contractually lock up extra capacity that they may not need, if they anticipate a capacity crunch. This effect would cause capacity prices to rise temporarily above replacement cost levels.

Q. What are the implications of these cycles for market forecasting and stranded cost determination?

A. Commodity price forecasts should be modeled either as trend forecasts, reflecting capacity replacement costs, or as cycle forecasts, where prices cycle between short-run marginal costs and demand-determined peak prices. PP&L, however, has constructed a hybrid approach (in the near term, short-run marginal costs and, in the longer term, prices capped at replacement costs with no provision for market tightness) that produces a more conservative forecast than either of these two methods. Because it is important for rate setting and CTC determination to reflect the likelihood that prices in the near term will start at levels below replacement costs, PP&L's forecast should reflect at least one period of tight capacity and higher prices in the future.

Q. How do PP&L's fuel price forecasts compare to other publicly available independent forecasts?

A Based on a comparison of Dr. Jones' forecasts with other independent forecasts of fuel costs, I find that his forecasts are generally in the lower end of the range of independent forecasts. Dr. Jones estimates future natural gas, coal and oil prices by applying an "escalator" to actual 1996 prices. By applying his price escalators (provided in Exhibit STJ-3) to 1996 prices reported by the Energy Information Administration, it is possible to compare forecasts developed using his methodology with independent forecasts for various fuels.

Several independent forecasts of these prices are reported by the Energy Information Administration. Comparisons of these independent forecasts with forecasts developed using Dr. Jones' escalators are provided in various tables below:

TABLE 1

Year	Forecast of Natural Gas Lower 48 Wellhead Price (nominal $ per thousand cubic feet)				
	PP&L	EIA	WEFA	DRI	AGA
2005	$2.61	$2.48	n/a	n/a	n/a
2010	$2.95	$2.91	$3.52	$3.22	$3.04
2015	$3.34	$3.49	n/a	$3.90	$3.44

Source: Comparison forecasts were obtained from Annual Energy Outlook 1997, published by the Energy Information Administration. These forecasts were converted into nominal dollars using Dr. Jones' assumption of a 2.5% inflation rate throughout the forecast period. AGA forecasts represent average acquisition price. The 1996 average Lower 48 wellhead price reported by EIA is $2.25 per thousand cubic feet.

Overall, these comparisons indicate that Dr. Jones' escalators produce forecasts that are typically in the lower end of the range of independent forecasts (consistently, for all fuels). In the case of natural gas, while Dr. Jones' forecast is slightly higher than the single comparison forecast available for 2005, it is lower than three of four comparison forecasts for 2010 and all three available comparisons for 2015.

TABLE 2

Year	Forecasts of Delivered Coal Prices (nominal $ per million BTU)			
	PP&L	EIA	WEFA	DRI
2005	$1.49	$1.59	n/a	n/a
2010	$1.62	$1.74	$2.01	$1.59
2015	$1.76	$1.82	$2.33	$1.74

Source: Comparison forecasts were obtained from Annual Energy Outlook 1997, published by the Energy Information Administration. These forecasts were converted into nominal dollars using Dr. Jones' assumption of a 2.5% inflation rate throughout the forecast period.

Notes:
(1) The 1996 average delivered price of coal reported by EIA is $1.29 per million BTU.
(2) The WEFA forecast for 2013 is shown here for the year 2015.

TABLE 3

Year	Forecast of World Crude Oil Price (nominal $ per barrel)						
	PP&L	EIA	DRI	WEFA	IEA1/IEA2	PEL	PIRA
2005	$23.85	$25.24	$23.81	$25.49	$32.68/22.22	$25.60	$20.05
2010	$26.99	$29.56	$30.36	$31.92	$36.98/25.14	$28.97	n/a
2015	$30.54	$34.38	$37.10	$39.56	n/a	n/a	n/a

Source: Comparison forecasts were obtained from Annual Energy Outlook 1997, published by the Energy Information Administration. These forecasts were converted into nominal dollars using Dr. Jones' assumption of a 2.5% inflation rate throughout the forecast period.

Notes:
(1) The 1996 average refiner acquisition cost of imported crude oil reported by EIA is $20.57 per barrel.
(2) IEA1 and IEA2 refer to the International Energy Agency capacity constraints case and energy savings case in World Energy Outlook, 1996, as reported in Annual Energy Outlook 1997.

For coal, Dr. Jones' forecasts are a few pennies per million BTU higher than the lowest of the forecast comparisons (DRI) for 2010 and 2015. EIA and WEFA forecasts are between 10 and 57 cents per million BTU higher than Dr. Jones' forecasts from 2005 to 2015. For crude oil, Dr. Jones' forecasts are lower than all three available comparison forecasts for 2015, and five of six comparisons for 2010. For 2005, Dr. Jones' forecast is lower than four of seven comparisons, and is just a few pennies per barrel higher than one of the three remaining comparison forecasts.

Q. Is PP&L's forecast based on a realistic capacity expansion scenario?

A. PP&L's price forecast is based on optimal capacity configuration and perfect foresight for demand. This precludes periods of tight capacity and high demand-based pricing. It also precludes periods of excess capacity and marginal cost pricing, except for the near term where capacity is determined sub-optimally (i.e., by utility planners in the past).

Q. Are PP&L's expectations for plant closures realistic?

A. As in the case of other assumptions, PP&L's assumptions are not unreasonable, but they are quite conservative. In particular, in modeling PJM plant availability, PP&L has conducted no economic tests to determine whether existing plants will close before the end of their engineering lives.[16] Under competition, generating plant owners will certainly sharpen up their pencils and carefully evaluate plant shutdowns on an incremental cash flow basis. It is likely that aging plants, particularly nuclear plants, that require significant ongoing capital expenditures and have high 'fixed' O&M costs, will close before the end of their useful lives, particularly if owners rely on market price

[16] See OCA-III-77.

forecasts similar to PP&L's. Moreover, generators with numerous plants will quickly realize that shutting some of their facilities (again, particularly nuclear plants), will have a favorable impact on market prices earned at other facilities.

Q. Are there indications that other generators are considering early closure of some generating stations?

A. Yes. Recent press reports (see Exhibit RDK-4) suggest that "premature" nuclear plant closures are very possible. Dr. Jones, by contrast, excludes the potential of plant closures as too "speculative" to be reasonable for developing a price forecast (see OSBA-I-27).

Q. Are PP&L's capacity prices realistic?

A. The methodology cited by Dr. Jones in his testimony is well grounded in economic theory, namely that capacity prices in the near term must reflect the going forward incremental costs of existing capacity.[17] In the longer term, the combination of capacity and energy prices must be sufficient to induce new plant construction. In practice, Dr. Jones' response to OSBA-I-24 indicates that he has apparently relied on information provided to him by PP&L personnel based on actual transactions for developing near-term capacity price forecasts, rather than the theory he describes in his testimony.[18] Moreover, Dr. Jones has refused to provide workpapers associated with this determination

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[17] Dr. Jones succinct description is, "Given the present surplus of capacity, this [capacity] market clears near the net cost of keeping capacity in operation." (PP&L Statement No. 7, page 12, lines 10-11)

[18] Note also that, had Dr. Jones used a going-forward incremental cost methodology (based on the highest incremental cost for surviving capacity) for determining capacity prices, he could credibly have argued that potential payments for various ancillary services were included in the capacity prices. However, with his method, it is impossible to determine whether such payments are correctly reflected. Since an ISO is not yet established and a market for ancillary services in place, it does not seem likely that potential ancillary service revenues are correctly reflected in Dr. Jones' capacity price.

on legal grounds. In the absence of the detailed information, I cannot evaluate the reasonableness of the forecast.

Q. Does PP&L incorporate any other conservative assumptions into its EGEAS model?

A. There are a couple that I have identified. First, by using a probabilistic approach to capacity availability in its EGEAS model, PP&L appears to effectively assuming that forced outages among plants are uncorrelated.[19] To the extent that forced outages are correlated, due to extreme weather conditions for example, PP&L's forecast understates periods of capacity shortages and demand-driven prices. Second, non-utility generators are modeled as must-run facilities with zero cost (OSBA-I-33). It is likely that at least some of these facilities have marginal costs in excess of the PJM system spot price at certain times. Under those conditions, the NUGs would purchase spot market power to meet their contractual obligations, rather than generate. By modeling these facilities as zero cost facilities, Dr. Jones effectively lowers the supply curve and reduces forecast market prices.

Q. After incorporating all these forecasts, are the prices forecast by Dr. Jones sufficient to justify the addition of new capacity at the times he forecasts?

A. My analysis of the information provided by Dr. Jones suggests that the prices are not sufficient, for capacity needed in the early part of the next decade. Exhibit RDK-2, Schedules 5 and 6, present two cash flow analyses of new gas-fired combined cycle generating units, that begin operation in 2005. Both examples utilize Dr. Jones'

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[19] My understanding is based on Dr. Jones' response to OSBA-I-18. The unplanned outages appear to be modeled as a percentage reduction in available capacity in every period. By applying these probabilistic reductions to all plants uniformly, forced outages are effectively modeled to be independent.

assumptions for costs and revenues, as best I could determine from various interrogatory responses. Version 1 (Schedule 5), utilizes extremely favorable assumptions regarding costs (no gas transmission costs, no maintenance capital expenditures, no working capital requirements, and no decommissioning costs). As shown, however, it produces only an internal rate of return below Dr. Jones' assumed cost of equity (i.e., a negative NPV at Dr. Jones' reported cost of equity). In Version 2 (Schedule 6), where I include very modest provisions for the excluded costs, the project will not come close to providing an adequate return.

Q. **Does Dr. Jones agree that the prices are insufficient to attract new capacity?**

A. No, Dr. Jones has testified that the prices are sufficient (see PPLICA-VII-1(b)). The OSBA is attempting to resolve this difference as discovery proceeds.

Q. **In evaluating stranded cost NPV analyses, do you believe that the Commission should rely on conservative or optimistic forecasts of future economic value?**

A. In general, I recommend "leaning" a little to optimistic forecasts of market value. Another way to look at stranded costs is to define them as the difference between the market value of a utility's assets and its book value. If a utility can sell its assets at book value, it has no stranded costs.[20] Thus stranded costs could be valued by requiring divestiture of generating plants, by the difference between the market sale price of the assets and the book value. If a public sale offer is made, the sale price of the assets will

[20] Alternatively, stranded costs can be defined as the market price of a utility's equity less the book value of the equity (as opposed to the market-book difference in asset value). Often, the market value of debt differs somewhat from the book value of the debt, due to changes in market interest rates. Since utility shareholders are generally not subjected to the risks of interest rate fluctuations, measuring stranded costs on an equity basis is probably the reasonable approach.

reflect the market's assessment of the value of the facilities. As Professor Kalt recognizes, preparing the NPV calculation requires an enormous number of assumptions, about which reasonable analysts will disagree (see OSBA-I-4(b)). These assumptions include market demand levels, plant generation and capacity factor levels, fuel and O&M costs, market energy, capacity and ancillary service prices, plant economic life, refurbishment potential, decommissioning costs, plant shutdown decisions, replacement capacity costs, discount rates, tax rates, allowed regulatory rates of return, etc. Moreover, NPV calculations are notoriously sensitive to modestly different assumptions. If stranded costs were determined by divestiture, the market's expectations for all of these factors would be incorporated into the calculation, and not those of the parties with vested interests in a regulatory proceeding (utilities, customers and competitors). Thus, in determining stranded costs, the Commission should try to incorporate assumptions that would reflect those of potential buyers. Of course, if PP&L's assets were to offer some of its generation assets for public sale, it can safely be assumed that they would sell to the bidder with the highest offer price. And, the successful buyer will be the one who is most optimistic about the economic prospects for the facility, either in future market prices, cost reductions, or any of the other myriad factors that go into determining market value. Thus, in evaluating stranded cost calculations, the Commission should, utilize forecasts that reflect assumptions on the optimistic side of reasonable, rather than the pessimistic side.

5 PP&L's Proposed "True-Up" Mechanism

Q. Please summarize PP&L's 'true-up' mechanism for stranded cost recovery.

A. In Mr. Kleha's testimony, PP&L proposes that the CTC recovery period be shortened or lengthened to allow for full recovery of the stranded cost amount determined in these proceedings by the Commission. While Mr. Kleha is not explicit in his testimony, OSBA-I-11 suggests that PP&L interprets its stranded cost claim for the purpose of this mechanism as its $4.1 billion net present value figure associated with proposed CTC revenues (subject to the rate cap) and not the $4.6 billion in computed stranded costs. That response also suggests that the variance will be computed, not on a net present value basis, but on a nominal dollar basis.[21]

Q. What is the statutory basis for this mechanism?

A. §2808(f) of the Act states:

> *". . . The Commission shall establish procedures for the annual review of the competitive transition charge. The review shall reconcile the annual revenues received from the charge with the annual amortization of transition or stranded costs approved by the Commission under this section. The Commission shall adjust the competitive transition charge based upon underrecovery or overrecovery of the annual amortization amount."*

Q. Is your interpretation of this provision the same as Mr. Kleha's?

A. I agree with Mr. Kleha that the Act does not call for annual reviews of the complex calculation of stranded costs. I also agree that the Act appears to provide for a reconciliation of stranded costs and stranded revenues, similar to the ECR process.

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[21] The CTC revenues reported in the example shown in OSBA-I-11 do not match those shown in other PP&L exhibits. The OSBA is pursuing clarification.

However, as I understand that the ECR process does reflect time value of money, I do not think that the mechanism should be developed on a strictly nominal dollar basis. More importantly, however, PP&L's proposal to extend the collection period in the event of under-recovery appears to be a strategy simply for getting around the rate cap and constrained transition period that are important features to the Act.

Q. Does PP&L's proposal have advantages?

A. Yes. First, as Mr. Kleha notes, the proposal is administratively simpler than the ECR mechanism. Second, PP&L's approach allows for offsetting years of under-recovery of CTC revenues with years of over-recovery, without constant adjustment of CTC rates. This approach adds stability and predictability to the rates. Third, the mechanism allows for an early end to the CTC, should PP&L's delivery volumes experience higher than expected demand growth. (For example, PP&L's CRD approach for CTC charges, discussed in the next section, is designed to stimulate demand.)

Q. What do you propose for the 'true-up' mechanism?

A. I recommend that PP&L's proposed approach be adopted as suggested by Mr. Kleha, but without an explicit guarantee of extending the period of collection in the event of a demand shortfall. Under PP&L's proposal, as it nears the end of the transition period, the Commission needs to determine by how much to shorten or lengthen the collection period. I propose that, at that time, the Commission determine whether or not to extend the period of collection of CTC. With that flexibility, the Commission can also consider whether stranded costs have been significantly higher or lower than forecast, as part of its determination for extending the recovery period. I also recommend that an explicit provision be made that CTC variances be applied to PP&L's proposed CTC revenues and not its stranded costs, and that over- or under-recovery should be determined on a net present value basis.[22]

6 Customized Rate Design (CRD)

Q. Please describe briefly PP&L's proposed Customized Rate Design (CRD) and the economic rationale therefor.

A. PP&L's proposed CRD approach, also referenced as the Progressive Rate Design method, is designed to recover approximately half of total CTC revenues through a customer-specific fixed charge, while recovering the balance through energy and demand charges. The customer-specific customer charge is determined from 1996 billing energy and demand levels, to avoid gaming by customers. The CRD, as proposed, is optional for residential customers, and mandatory for all other classes. PP&L justifies mandatory application of the CRD on an economic efficiency argument. By making the CTC more fixed and less variable, customer decisions regarding increasing or decreasing volume are based on price signals that are closer to marginal costs, and are therefore less distorted.

Q. Do you have any concerns about PP&L's proposed CRD approach?

A. Yes. I do not believe that it is necessary to make the CRD approach mandatory for all business customers, particularly smaller business customers, to achieve the economic efficiencies desired by PP&L. Moreover, a mandatory CRD approach is likely to be

[22] As discussed in Section 3, the discount rate for CTC revenues should be the after-tax cost of equity, as determined in these proceedings.

perceived as unfair by small business customers who have declining demand levels. As the credible reasons for allowing recovery of stranded costs are related to fairness, I find it ironic that PP&L relegates the fairness criterion to second-class status when devising a method for recovering those stranded costs.

Q. You indicate that allowing recovery of stranded costs is economically inefficient. Does PP&L agree?

A. Yes, of course. For example, Dr. Tierney testifies: "The Progressive Rate Design reduces the distortive effects of stranded cost collection on energy use. . . ." (PP&L Statement No. 9, page 6). Unless stranded cost recovery is precluded, there is no way to eliminate these 'distortive effects.'

Q. Do you agree with PP&L's claims regarding economic efficiency and the CRD?

A. Not completely. First, remember that any CTC is inherently less efficient than no CTC, either fixed or variable. Businesses who are considering locating in Pennsylvania, or who are considering moving elsewhere, could make inefficient decisions while the CTC exists, because those customers evaluate the total bill (the "going forward incremental" cost), not the short-run marginal cost. However, if I begin with the assumption that a CTC is necessary, I agree that an optional CRD is more economically efficient than a CTC that is based solely on energy/demand charges. As Dr. Tierney correctly notes, customers will see marginal energy/demand charges that are closer to marginal energy/demand costs, and will make more efficient decisions *about incremental demand*. I do not necessarily agree, however, that it is necessary for the CTC to be mandatory for it to be more economically efficient. For customers who are considering expanding their business and associated energy consumption, a CRD allows them the opportunity to pay only half a CTC on the expanded demand, providing a less inefficient price signal for expansion than requiring a full CTC on all incremental volumes. In an optional CRD scheme, these customers will choose the CRD. For customers with declining demands, however, the efficiency gains of the CRD are debatable. While a CTC tariff with a lower variable charge may create less inefficient incentives to a customer who is deciding whether to incrementally reduce consumption, the higher fixed component may exacerbate financial difficulties and contribute to bankruptcies for business customers. Thus, the inefficiencies of the high fixed component may outweigh the beneficial impacts of the lower variable component.

Q. **Dr. Tierney describes the CRD as "effective rate relief" (PP&L Statement No. 9, page 20). Do you agree with this characterization?**

A. No. It is correct that the mandatory CRD will reduce, relative to the existing tariff, the average per kWh bill for GS customers whose load increases from base year levels.[23] However, the converse is also true -- GS customers whose energy consumption declines from 1996 levels will face a higher per kWh bill than they would under the existing approved rates. It is hard to understand how higher unit rates relative to the existing tariff constitute "rate relief." Because PP&L is assured recovery of a fixed amount of CTC under §2808(f) and its "true-up" proposal, the mandatory CRD represents a higher

[23] Because demand generally grows in PP&L's forecast, use of the CRD results in an overall reduction in revenue relative to what the existing tariff would produce (as detailed class by class and year by year in OCA-III-39). As such it might be considered rate relief, at least on average. However, if PP&L did not have the CRD proposal, it is at least possible that the higher CTC revenues would surpass the allowed stranded cost claim. In that event, the CRD method can be seen as another approach for allocating surplus CTC revenues, as discussed earlier in Section 2. Since this scheme allocates the surplus only to growing customers and penalizes shrinking customers, it is not a particularly equitable method.

allocation of CTC charges to customers with shrinking loads and a lower allocation to those with declining load.

Q. Turning to the issue of equity in the overall restructuring process, how do the small business classes fare under the transition to competition?

A. I believe that all classes will eventually benefit from a competitive marketplace for generation, either directly or indirectly. As such, the small business customers will eventually benefit from deregulation, *if an actively competitive market develops.* However, because of its revenue neutrality provisions, the Act prolongs the burden currently being borne by the small business classes. As shown in Mr. Kleha's cost allocation study, rates of return for the GS-1 and GS-3 classes are 15.7 percent and 11.4 percent respectively, while average returns are 9.5 percent. Under the Act's rate cap provisions, the GS classes will have no opportunity to close the gap between their rates of return and those of the other classes. Similarly, under the "residual CTC" method put forth by PP&L, the per kWh CTC revenues from the GS classes are higher than from any other class. A comparison is shown in Exhibit RDK-2, Schedule 7 and summarized in Table 4 below for 1999.

TABLE 4 **AVERAGE 1999 CTC RATES MAJOR PP&L RATE CLASSES**	
Rate Class	Cents per kWh
RS	2.91
GS-1	**4.17**
GS-3	**3.26**
LP-4	2.99
LP-5	2.81
LP-6	2.40
IST	1.24
Source: OCA-III-39	

Q. Do you believe that a mandatory CRD meets the rate design requirements of fairness and avoidance of undue discrimination?

A. No. First, offering an optional CRD to only the residential classes is needlessly discriminatory between classes.[24] PP&L justifies this discrimination on the basis of higher price sensitivity within the business classes.[25] However, PP&L's reasoning is suspect as it applies to small businesses. Econometric evaluation of electricity price

[24] Note that §2804(5)(7) of the Act precludes unreasonable discrimination against one class to the benefit of another.

[25] See Dr. Tierney's testimony at page 32 line 32 to page 33 line 3. In OSBA-I-41, Mr. Krall also indicates that only the residential customers are offered the option for the CRD "out of a concern for customer education." Ms. Lennon, on the other hand, indicates that ". . . customers, especially residential and small business customers, do not fully understand customer choice." (OCA-VI-17) Thus, if customer education were deemed a valid reason for offering the option to residential customers, it should also be offered to small business customers.

elasticities of demand in the commercial sector is much less robust than for either the residential or the industrial sector. The materials presented in this case do not suggest that demand is substantially more elastic in the commercial sector than in the residential sector. Moreover, demand responsiveness is likely to vary significantly between the various types of businesses included in the commercial sector. Thus, relying on price elasticity of demand to distinguish between the residential and the commercial sectors is not a convincing reason to discriminate.[26] Second, a mandatory CRD is inequitable within a class. Customers who have demands that are lower than 1996 levels are bearing a relatively higher share of the CRD than they would under generic tariff charges, which strikes me as unfair and contrary to the spirit of the Act. For example, small business customers may have demand levels that are below 1996 levels because (a) their business is declining, or (b) the 1996 demand level was unusually high. In neither case is it equitable to shift a greater share of CTC costs to these customers relative to the existing rates.

Q. What do you propose?

A. In the "fairness" spirit of stranded cost recovery, I propose that the GS classes be offered the same option as residential customers with respect to the CRD approach.

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[26] Also, PP&L's use of elasticity for rate design purposes is somewhat different than its historical approach. Proponents of Ramsey pricing (or sometimes "value-of-service" pricing) typically advocate recovering a greater portion of non-attributable costs from rate classes with more inelastic demands. Had PP&L followed this school of economics in the past, it would have advocated higher than average rates of return from the residential classes with less elastic demand. As shown in Mr. Kleha's cost allocation study, quite the reverse is true.

Q. Will your proposal affect PP&L's recovery of stranded costs?

A. It is possible that allowing the GS customer classes a CRD option will reduce PP&L's stranded cost recovery below those levels that it forecasts. Customers who expect to grow above base year levels will probably take the customized option, and those expecting to decline will take normal service. However, PP&L's ability to fully recover stranded costs will depend, among other factors, on whether PP&L's proposal for lengthening the CTC recovery period beyond 2005 is adopted. As detailed in Section 5, PP&L is allowed under §2808(f) of the Act to recover its approved CTC revenues, and has proposed a true-up scheme for doing so. If PP&L's proposal is approved, it will recover its full expected CTC revenues whether the CRD is mandatory or optional. If PP&L is not allowed to extend the CTC recovery period beyond 2005, there is some likelihood of reduced CTC recovery under this proposal.[27]

7 GS-1 and GS-3 Tariffs

Q. Please describe the impacts of PP&L's implementation of rate unbundling and the CTC on the basic GS-1 tariff.

A. As described in the testimony of Dr. Tierney and Mr. Krall, PP&L develops the CTC through a "residual CTC" or "bottom-up" method. Methodologically, PP&L takes the existing rate, deducts transmission/distribution costs, backs out forecast market prices, and

[27] It is also possible that this proposal will increase CTC revenues above those forecast by PP&L. Some customers, potentially for risk aversion reasons or because they dislike high fixed monthly charges, may choose to remain with full energy/demand charges in their CTC's, even if they think their demand will increase. This result will increase CTC revenues above those forecast (all other factors being equal).

leaves a residual CTC. However, for each rate class, each stage of this residual determination involves making certain tariff design decisions. For the GS classes, when backing out the transmission/distribution costs, PP&L has opted to assign customer charge and unblocked energy charge revenues to the transmission/distribution costs. This leaves a blocked energy charge and a demand charge. In backing out the market price, PP&L deducts market energy rates from the residual energy charges, and deducts market capacity charges from the demand charge. This leaves a blocked energy structure and demand charge for the CTC tariff. This procedure is detailed for the base year (1999) in Table 5 below:

TABLE 5

BASE YEAR GS-1 CTC DEVELOPMENT -- PP&L PROPOSAL

	Customer Charge ($)	Energy: <150 kWh/kW	Energy: >150 kWh/kW	Demand >5kW
Base Rates	$7.48	10.436	7.841	$2.00
Deduct T&D	($7.48)	(3.104)	(3.104)	--
Net Rates	$0.00	7.332	4.737	$2.00
Deduct Market Rates		(2.420)	(2.420)	($1.86)
Gross CTC		4.912	2.317	$0.14
CRD Adjustment		(2.456)	(1.158)	($.07)
Net CTC		2.456	1.158	$.07

Q. **Are there problems with this approach?**

A. Yes. The chief difficulty relates to the GS-1 demand charge. Due to the wide variety of size of customer and metering capabilities, the demand charge on the GS-1 tariff applies only to billing demand above 5 kW. Customers who are not demand-metered, or who have billing demand of less than 5 kW, will see no reduction in their transmission/distribution service bill associated with the market rate demand credit, because they now pay no demand charge. Moreover, the market rate credit will apply only to demand over 5 kW. Thus, smaller GS-1 customers will effectively face rates for utility generation service that are below the market rates forecasted by Dr. Jones.

Q. Do these problems continue beyond 1999?

A. Yes. In fact, they get worse. As the market capacity price rises, the proposed residual CTC demand charge becomes negative, bottoming out at a negative $2.30 per kW per month in 2002. This negative demand charge more than offsets the demand charge that is built into the GS-1 block structure.[28] Under certain circumstances, a customer could face a CTC that is negative, as shown in Exhibit RDK-2, Schedule 8.

Q. What is the solution to this problem?

A. A better but equally simple approach would be to leave the existing demand charge in the transmission/distribution rates. Market demand charge revenues should then be backed out of the first block energy rate, and, if necessary, the second block. A detailed proof of revenues for 1999 tariff levels (at base year volumes) that would result from implementing only this change is shown in Exhibit RDK-2, Schedule 9.

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[28] PP&L's block structure contains an implicit demand charge, as it has a higher first block rate for the first 150 kWh per kW of billing demand, and a lower second block rate. Thus, for all customers above 150 kWh per kW (a load factor of about 21 percent on a billing kW basis), the effective demand charge is the difference between the blocks times 150 hours. In the case of 2002, that effective demand charge is $1.90, and is therefore more than offset by the negative $2.30.

Q. Are there any other problems with the GS-1 tariff?

A. Yes, potentially. PP&L has decided to recover all transmission and distribution costs, which are essentially fixed, with a flat energy tariff and a modest customer charge. While this design is admirably simple, it may not reflect the load patterns within the GS-1 class. If larger customers have higher load factors, for example, small GS-1 customers will be 'subsidized' by larger customers. Similarly, since the customer charge is well below allocated customer costs, larger GS-1 customers will subsidize smaller customers on that account as well.

Q. How do you propose to correct for this potential problem?

A. Absent a detailed load research study of the GS-1 class, I recommend that PP&L not adopt a flat delivery charge at present. If such a change is warranted, it is best addressed in rate proceedings after the end of the transmission/distribution rate cap in mid-2001. I recommend that the existing block structure be maintained in each area of the GS-1 tariff; namely the transmission/distribution charge, the CTC, and the generation charge. Table 6 below, and Exhibit RDK-2 Schedule 10, detail such a tariff for base year 1999.

TABLE 6 BASE YEAR GS-1 CTC DEVELOPMENT -- RDK APPROACH				
	Customer Charge ($)	Energy: <150 kWh/kW	Energy: >150 kWh/kW	Demand >5kW
Base Rates	$7.48	10.436	7.841	$2.00
Deduct T&D	($7.48)	(2.661)	(1.995)	$2.00
Net Rates	$0.00	7.775	5.846	$0.00
Deduct Market Rates		(3.205)	(2.420)	
Gross CTC		4.570	3.426	
CRD Adjustment		(2.285)	(1.713)	
Net CTC		2.285	1.713	

Q. Does the proposed GS-3 tariff have problems similar to the GS-1 tariff?

A. The proposed GS-3 tariff does not have the demand charge problem that the GS-1 tariff has, since the GS-3 demand charge applies to all billing demand. As such, PP&L's approach to back out all of the market demand charge from the existing demand charge is not unreasonable. However, the proposed GS-3 transmission/distribution tariff is based on a flat energy charge. As in the case of the GS-1 tariff, absent a load research study, I think it better to keep a blocked energy charge in both the delivery charge and the CTC. A proof of revenue example for 1999 (base year volumes) is presented in Exhibit RDK-2, Schedule 11.

8 EDI/IDI Credits

Q. Please summarize PP&L's proposal for continuation of EDI and IDI rate credits in its restructuring proposal.

A. In the current tariff, these credits are scheduled to be phased out over the 1998 to 2000 time period. Instead of phasing out these credits, PP&L proposes to extend them through the transition period, to 2005. The credits will be available only to customers who take utility generation service (BUSS).

Q. What is PP&L's reason for continuing the credits?

A. PP&L interprets the Act to mandate continuation of the credits.

Q. Do you agree?

A. I can neither agree nor disagree -- I do not clearly understand how the Act should be interpreted with respect to its rate cap. §2804(4) of the Act defines rate caps generally as precluding total charges as approved by the Commission from increasing. It is not clear to me that, since the Commission has approved a tariff specifying phaseout of these credits, whether the rate cap mandates continuation of those credits or not. I must leave this interpretation to the Commission.

Q. Are there economic considerations regarding continuation of the discounts?

A. Yes. The discounts were designed to encourage additional load, by providing lower cost service for loads above base levels. Since the EDI credit is now closed to new entrants, and the IDI credit will be available to new entrants only until the end of this year, it can be inferred that load enhancing discounts are no longer necessary to promote additional demand. Moreover, those customers who took advantage of these discounts did so with the knowledge that the discounts would be phased out. Thus, by continuing the discounts, the customers who obtained the discounts will benefit to a larger extent than they had expected (and therefore by more than they needed to stimulate the additional load). Thus, there is no economic development reason to continue the discounts beyond the pre-determined phase out period.

Q. If the Commission determines that the discounts need not be maintained, what would be the impact on PP&L's restructuring proposal?

A. Under PP&L's proposal, the EDI/IDI discounts are applied to the market price-based utility generator service (BUSS) rates. As such, the discounts reduce PP&L's revenues for BUSS to those customers below market rates. If the discounts were eliminated, and no other changes were made, PP&L's overall revenues would increase above the current forecast levels. Again, I think two interpretations of the Act are possible. The additional revenues could be considered as similar to CTC revenues, providing a greater recovery of the stranded cost claim (i.e., in PP&L's proposal, the $4.2 billion NPV of CTC revenues would rise, provided that they don't exceed the $4.6 billion in stranded costs). Alternatively, this increase could be perceived as a violation of the revenue neutrality intent of the Act, and the revenue neutrality would need to be restored by adjusting CTC revenues downward to compensate. In the former case, PP&L shareholders benefit from the increased revenues; in the latter, it is the customers who benefit. I do not see a clear economic answer as to which is preferable, and defer the problem for evaluation on legal and fairness grounds.

Q. Suppose the Commission agrees with PP&L that the Act requires that the EDI/IDI credits be maintained through the transition period. What options does PP&L have for offering the credit?

A. If the Commission determines that the EDI/IDI credits must be maintained, PP&L has the choice of applying the credits only to customers taking utility generation service (BUSS) or continuing the credits to all currently eligible customers.

Q. What are the relative advantages of the two approaches?

A. The key disadvantage of PP&L's proposed approach is that it discourages entry and competition by other suppliers in PP&L's service territory. The customers who are now eligible for the credits will be effectively locked into utility generation service. The EDI/IDI discounts of $10 per MWh and $12 per kW per year represent a substantial percentage of Dr. Jones' market price forecasts for the transition period. It is most unlikely that customers will find alternative suppliers willing to offer lower prices below the discounted BUSS service. Thus, all existing beneficiaries of the discounts will continue to take utility generation service, and PP&L will provide the full amount of the discounts in every year. If PP&L were to make the discounts available to all existing beneficiaries without requiring them to take utility service, competitors could realistically compete for these customers. For that reason, I recommend that, if the discounts must be continued, that they be available to all eligible customers regardless of their choice of generator.

Q. If the credit is offered to all customers, should it be deducted from CTC revenues for the purpose of comparing CTC revenues and stranded costs?

A. No, the discount should stand alone from the CTC tariff provisions. CTC tariff provisions are developed from gross revenues, and it would therefore be inappropriate to deduct EDI/IDI credits. Note that PP&L's current proposal does not deduct the discounts from CTC revenues.

9 Phase-In Issues for Small Business Customers

Q. Do you have any concerns about PP&L's proposals for the phase-in period for access to alternative generation suppliers?

A. Unfortunately, the Act specifies a two-year phase-in period during which some customers will be ineligible to choose their own generation service suppliers. This restriction raises potential discrimination and equity concerns with respect to the small business classes. First, customers who compete against one another may be treated differentially, depending on their access to alternative generation suppliers. Second, due to the random drawing approach, larger commercial customers could dominate the eligible customer group, particularly if commercial classes are combined as PP&L has proposed for its pilot program.

Q. How does PP&L propose to address any potential competitive disadvantages caused by this phase-in period?

A. Mr. Baumann's testimony indicates that PP&L is sensitive to this problem, but that no specific procedures have been developed for solving it. He testifies, *"If such a* *competitive distortion arises, the Company will review the situation on a case-by-case basis and attempt to resolve it to the satisfaction of the affected customers."* (PP&L Statement No. 14, page 5)

Q. **Are you proposing a more specific solution?**

A. I recommend that the Commission provide general guidance on how these circumstances should be addressed, and that PP&L develop specific procedures. First, PP&L should be allowed to offer competitive access to customers who have demonstrated a competitive disadvantage vis-a-vis other Pennsylvania competitors by being excluded from such access. To do so, PP&L could potentially run afoul of the 33 percent and 66 percent limits on eligible demand that are specified in §2806(b) of the Act during the phase-in period. If that constraint is a legal concern, I suggest that PP&L initially target 30 percent and 60 percent participation for the two phase-in years, to leave room under the cap for competitive adjustments. In addition, I suggest that PP&L develop specific details about the information that will be required from a customer who appeals for competitive relief, and also details for the appeal process.

Q. **Turning to your other phase-in issue, what is your concern about customer size and relative access to competitive generation service?**

A. In its pilot program, PP&L aggregated all of the commercial customer classes into "major customer classes" for the purpose of determining eligibility for participation within the 5 percent cap. This aggregation should not be adopted for the actual phase-in to competition. The commercial classes consist of a very wide range of businesses with a wide range of load sizes and shapes. Larger customers within an aggregated class will likely have a greater interest in pursuing competitive alternatives, and could easily dominate the customer group that is allowed competitive access. Such an outcome would be unfair to smaller business customers and generally contrary to the non-discriminatory spirit of the Act. Thus, I recommend that the limits to competitive access be applied on a rate class basis, where rate classes are distinguished between customers served under the GS-1, GS-3 and GH rate classes.

Q. Is delineation between the GS classes sufficient to preclude domination by large customers?

A. Not necessarily. In the GS-1 class, the top 5.7 percent of customer bills account for 33 percent of kWh consumed, based on the 1996 bill frequency analysis shown in Exhibit OGK-5. For the GS-3 class, the top 3.8 percent of customer bills constitute 33 percent of kWh consumption. Thus, even with random sampling, large customers could potentially dominate the competitive access within both classes.

Q. How can PP&L prevent large customers from dominating those eligible for competitive service in the phase-in period?

A. PP&L's general approach of using a random sampling of customers in the event of over-subscription is preferable to a strict first-come-first-served approach, since large customers are more likely to "come first." In addition, however, I suggest that a second constraint be added to PP&L's method. I propose that minimum levels of customer participation be set for the GS classes for each of the two phase-in years. Thus, if the random drawing process produces too few customers, these large customers can be limited in the amount of their load that is subject to competition. This limit would then allow more customers access to competitive suppliers. I propose that 20 percent and 40 percent of the number of customers be set as minima for both the GS-1 and GS-3 classes.

Q. Does this conclude your direct testimony?

A. Yes it does.

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

EXHIBITS OF

ROBERT D. KNECHT

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

EXHIBIT RDK-1

Résumé and Schedule of Appearances Before Regulatory Authorities

ROBERT D. KNECHT

2 July 1997

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT
Treasurer

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than sixteen years of consulting experience, focusing primarily on the metals, mining and energy industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. In addition, as Treasurer of Industrial Economics, Incorporated (IEc), Mr. Knecht is responsible for the firm's accounting controls, cost forecasting, financial management and tax planning. Mr. Knecht also oversees IEc's computer resources function, and serves as administrator of the firm's pension plan.

Mr. Knecht's recent consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht has provided analysis and expert testimony in several base rates and purchased gas cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht's testimony focused on cost allocation and rate design issues.

- For the Independent Power Producers Society of Alberta, Mr. Knecht has provided analysis and recommendations regarding electric industry restructuring strategies. Mr. Knecht also provided expert testimony with respect to transmission cost allocation and rate design.

- For the Electric Power Research Institute, Mr. Knecht managed several studies and enhancements of models that compute the economic costs of environmental externalities associated with electric generating stations.

- For a major South American iron ore mining company, Mr. Knecht assembled and managed an international team of consultants to review and evaluate the company's strategic plan. Mr. Knecht oversaw the development of conclusions and recommendations in the areas of markets, the resource base, development of the resource, processing operations and finance.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining IEc as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT
Treasurer

Regulatory Economics

Mr. Knecht consults and provides expert testimony in the field of regulatory economics, focusing primarily on issues of cost allocation and rate design. His clients include both utilities and consumers, competitors, and regulators of public utilities. Representative assignments are listed below.

- Over several years, analysis and expert testimony of cost allocation and rate design practices of the three major Ontario natural gas distribution utilities, on behalf of the Ontario Energy Board staff and the Canadian Independent Gas Marketing Association.

- Cost allocation and rate design study and expert testimony for a small Ontario gas distribution utility, Natural Resource Gas, Ltd.

- Analysis and litigation support regarding accounting, financial and capacity planning procedures of New Brunswick Power Corporation, and presentation of expert testimony on cost allocation and rate design, in a series of generic regulatory hearings, on behalf of a group of large industrial customers.

- Analysis of the cost allocation and rate design procedures of Consumers' Gas, Ltd., for the Canadian Independent Gas Marketing Association.

- Analysis of the cost allocation and rate design procedures of the three major Ontario natural gas utilities, for the staff of the Ontario Energy Board.

- Economic analysis and modelling of U.S. Postal Service proposals for allocation of peak load labor and equipment costs in 1987 and 1990, for the American Newspaper Publishers Association.

- Evaluation of the cost allocation and cost recovery procedures of a domestic telecommunications firm providing aircraft to ground data communications.

- Assessment of alternative methodologies for defining the electric rate classes of Maritime Electric Corporation, for the Prince Edward Island Ministry of Energy and Forestry.

- Several evaluations of the cost allocation and rate design procedures of the Nova Scotia Power Corporation, for a group of interruptible electricity consumers, and subsequently for a large pulp and paper producer.

Regulatory Economics (continued)

- o Assessment of a proposed class-specific, risk-adjusted rate of return methodology for natural gas distribution utilities, for the staff of the Ontario Energy Board.
- o Preparation of rebuttal analysis regarding management prudence in the construction of the River Bend Nuclear Generating Station, for Gulf States Utilities.

Economic Consulting

Mr. Knecht's practice also includes the application of economics, finance and decision analysis theory to practical problems facing businesses, law firms and government. His assignments include industry and company planning, market forecasting, policy analysis and economic damage assessment. Representative assignments are listed below.

- o Economic, market and cost analysis for a team of international consultants preparing a restructuring study of the Polish steel industry, in conjunction with the World Bank.
- o Economic and policy analysis for a U.S. engineering firm preparing a strategic planning study for the state-owned steel company in Venezuela.
- o For the U.S. Environmental Protection Agency, evaluation of the impact of Clean Air Act amendments on major industrial facilities that are closing or are threatened with closure.
- o Econometric analysis of world steel consumption patterns for a major international iron ore producer.
- o Litigation support services relating to the business planning activities of a major West Coast construction and fabrication concern, in a fraudulent conveyance lawsuit.
- o Review and analysis of direct and rebuttal evidence regarding economic damages to recreational activities, for the U.S. Department of Justice.
- o Decision analysis and calculation of economic damages in an ERISA discrimination lawsuit, for a major domestic manufacturing company.

Economic Consulting (continued)

- Financial, econometric and strategic planning analyses for an international engineering firm, engaged in the preparation of a strategic plan for the steel industry of Nigeria.

- Economic analysis and econometric modeling of import behavior in the domestic carbon steel and wire rope markets, for hearings before the U.S. International Trade Commission.

- Financial analysis and damage assessment for a major domestic law firm, in support of a major anti-trust suit involving the potential construction of a coal slurry pipeline.

- Economic analysis of imports of iron ore pellets into the U.S., for a major international iron ore producer.

- Construction of an economic model of domestic metallurgical coke demand, for the U.S. Environmental Protection Agency.

- Econometric analysis of energy demand, by energy type, region and sector, and management of a sectoral supply-demand model of energy production and use.

Management Consulting

Mr. Knecht has also provided management consulting services to various basic industrial clients, focusing primarily on planning and decision-making. Representative assignments are listed below.

- Competitive dynamics analysis of the world iron ore industry and preparation of strategic recommendations for a major South American mining company.

- Task leader in a management audit of a New Jersey natural gas local distribution company.

- Development of a strategic plan and various business plans for a domestic specialized producer of carbon and alloy steel bars.

- Economic analysis and financial modeling of labor and employee benefits costs for a large integrated steel producer. Preparation of recommendations for labor relations and bargaining strategies.

Management Consulting (continued)

- Analysis for the restructuring of the marketing function of a large domestic manufacturing company, including segmentation analysis, field interviews and competitor comparisons.

- Market survey and analysis of the domestic hot finished seamless steel tube markets, for a U.S. producer.

- Strategic and business plan development for a major Polish steel producer.

ROBERT D. KNECHT

SCHEDULE OF APPEARANCES BEFORE REGULATORY BOARDS

Docket #	Regulatory Board	Utility	Date of Appearance	Client	Topic of Testimony
1996 Electric Utility Tariff Applications	Alberta Energy & Utilities Board	TransAlta Utilities Alberta Power Edmonton Power Grid Company of Alberta	October 1996	Independent Power Producers Society of Alberta	Industry restructuring; transmission cost allocation and rate design.
R-963612	Pennsylvania Public Utilities Commission	PG Energy, Inc.	October 1996	Pennsylvania Office of the Small Business Advocate	Cost allocation and rate design -- direct and rebuttal.
R-953444	Pennsylvania Public Utilities Commission	Trigen-Philadelphia Energy Corp.	November 1995	Pennsylvania Office of the Small Business Advocate	Steam energy cost rate -- direct and rebuttal.
--	The Public Utilities Board of Manitoba	Centra Gas Manitoba Incorporated	October 1995	Direct Energy Marketing Limited	Bundled transportation service rates, purchased gas cost deferral accounts.
R-953406	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	October 1995	Pennsylvania Office of the Small Business Advocate	Weather normalization, cost allocation and rate design.
R-953297	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Gas Division)	May 1995	Pennsylvania Office of the Small Business Advocate	Cost allocation and rate design -- direct and surrebuttal.
R-943271	Pennsylvania Public Utility Commission	Pennsylvania Power & Light	April/May 1995	Pennsylvania Office of the Small Business Advocate	Cost allocation and rate design -- direct and rebuttal
EBRO 488	Ontario Energy Board	Natural Resource Gas Limited	November 1994	Natural Resource Gas Limited	Customer classification, cost allocation and rate design.
1993 General Rate Application	Alberta Public Utilities Board	Alberta Power Limited	November 1994	Independent Power Producers Society of Alberta	Cost allocation and rate design for export transmission service.
R-942986	Pennsylvania Public Utility Commission	West Penn Power Company	August 1994	Pennsylvania Office of the Small Business Advocate	Cost allocation and rate design.
R-932862	Pennsylvania Public Utility Commission	UGI Utilities, Inc. (Electric Division)	March 1994	Pennsylvania Office of the Small Business Advocate	Cost allocation and rate design -- direct, rebuttal and surrebuttal.
EBRO 485, and Generic Direct Purchase Hearings	Ontario Energy Board	Consumers' Gas Company, Ltd.	August 1993, September 1993.	Canadian Independent Gas Marketing Association	Classification and allocation of marketing and administrative costs.

ROBERT D. KNECHT

SCHEDULE OF APPEARANCES BEFORE REGULATORY AUTHORITIES-- Page 2

Docket #	Regulatory Board	Utility	Date of Appearance	Client	Topic of Testimony
Hearings for Cost of Service and Rate Design	Nova Scotia Utility and Review Board	Nova Scotia Power, Inc.	May 1993	Bowater Mersey Paper Company, Ltd.	Classification of bulk power costs, rate design for interruptible service and other rate design issues.
Generic Hearing #4	Board of Commissioners of Public Utilities, Province of New Brunswick	New Brunswick Power Corporation	November 1991	Large Power Users Group	Review of cost allocation and rate design.
EBRO-470	Ontario Energy Board	Union Gas, Ltd.	February 1991	Ontario Energy Board Staff	Cost allocation and rate design for interruptible service and transmission costs; evaluation of load shifting study.
Rate Area Boundaries Hearings	Prince Edward Island Public Utilities Commission	Maritime Electric Co., Ltd.	February 1991	Prince Edward Island Department of Energy and Forestry	Customer classification by geographical area.
EBRO-467	Ontario Energy Board	Centra Gas, Ltd.	January 1991	Ontario Energy Board Staff	Cost allocation and rate design for special technology rates, cogen rates and bypass issues.
Arbitration Hearings	Arbitrator	ARINC, Inc.	July 1990	ARINC Inc.	Cost allocation and rate design for aircraft to ground data communications service.
EBRO-462	Ontario Energy Board	Union Gas, Ltd.	January 1990	Ontario Energy Board Staff	Seasonal cost allocation study, and allocation of costs to export markets.
NSPC-857	Nova Scotia Board of Commissioners of Public Utilities	Nova Scotia Power Corp.	February 1989	Interruptible industrial customers	Cost allocation and rate design of interruptible electric service.

EXHIBIT RDK-2

ANALYTICAL SCHEDULES

2 July 1997

Stranded Costs and CTC Revenues ($million)							
	CTC Revenues	Nuclear Stranded	Fossil Stranded	NUG's Stranded	Reg. Asset Stranded	Total Stranded	Over - Recovery
Disc Rt	7.920%	7.920%	7.920%	7.920%	7.920%	7.920%	
NPV	**4,155.95**	(2,917.12)	(729.40)	(665.99)	(393.08)	**(4,705.60)**	**(549.65)**
Disc Rt	11.500%	11.500%	11.500%	11.500%	11.500%	11.500%	
NPV	**3,786.86**	(2,343.83)	(632.05)	(587.71)	(314.33)	**(3,877.92)**	**(91.06)**
1999	949.27	(344.25)	(194.24)	(121.35)	(122.08)	(781.92)	
2000	877.70	(330.30)	(160.11)	(116.58)	(26.26)	(633.24)	
2001	776.06	(314.62)	(84.50)	(109.99)	(20.68)	(529.79)	
2002	686.53	(299.92)	(24.01)	(85.77)	(19.63)	(429.33)	
2003	664.09	(292.61)	(21.16)	(84.10)	(19.71)	(417.57)	
2004	643.91	(286.59)	(48.31)	(82.20)	(19.41)	(436.50)	
2005	652.25	(289.81)	(98.23)	(81.96)	(20.01)	(490.01)	
2006		(282.97)	(88.15)	(79.72)	(19.75)	(470.60)	
2007		(258.47)	(32.33)	(73.89)	(21.37)	(386.06)	
2008		(246.77)	(8.88)	(49.77)	(22.38)	(327.81)	
2009		(237.12)	1.67	(33.80)	(32.21)	(301.46)	
2010		(228.21)	(118.08)	(2.26)	(55.30)	(403.85)	
2011		(220.60)	(120.33)	(0.80)	(29.94)	(371.68)	
2012		(213.63)	(20.39)	(0.76)	(33.38)	(268.16)	
2013		(203.57)	124.37	(0.71)	(36.24)	(116.14)	
2014		(206.42)	(16.03)	(0.67)	(49.33)	(272.44)	
2015		(199.53)	(96.25)		(47.99)	(343.77)	
2016		(196.96)	(27.27)		(29.62)	(253.85)	
2017		(193.46)	(89.33)		(39.55)	(322.33)	
2018		(191.08)	(131.50)		(27.52)	(350.11)	
2019		(191.08)	(41.96)		(21.39)	(254.42)	
2020		(193.38)	6.87		(10.54)	(197.05)	
2021		(156.68)	7.63		(1.59)	(150.64)	
2022		(59.36)	8.42		(47.73)	(98.67)	
2023		(88.55)	9.22		0.70	(78.63)	
2024		56.09	10.04		(54.46)	11.67	
2025			9.52			9.52	
2026			10.37			10.37	
2027			11.24			11.24	
2028			12.12			12.12	
2029			13.03			13.03	
2030			13.94			13.94	
2031			14.87			14.87	
2032			15.84			15.84	
2033			16.89			16.89	
2034			15.50			15.50	
2035			14.64			14.64	
2036			15.55			15.55	
2037			16.48			16.48	
2038			17.41			17.41	
2039			18.35			18.35	
2040			19.28			19.28	
2041			20.18			20.18	
2042			21.25			21.25	
2043			22.81			22.81	
2044			5.72			5.72	
2045			(2.62)			(2.62)	

Example of Discounting Stranded Costs at WACC				
	NPV1 @ 8%	*NPV1 @ 12%*	*Period 1*	*Period 2*
Earnings under Regulation				
O&M Costs			$ 75.00	$ 75.00
Debt Costs			$ 15.00	$ 15.00
Income Taxes			$ 20.00	$ 20.00
Equity Return (after-tax)		***$ 56.79***	***$ 30.00***	***$ 30.00***
Revenue Requirement			***$ 140.00***	***$ 140.00***
Stranded Cost/CTC at WACC				
Market Revenues			$ 100.00	$ 100.00
Stranded Costs	$ 77.04		$ 40.00	$ 40.00
CTC Revenues	$ 77.04		$ 77.04	
Earnings under Deregulation plus CTC				
Market Revenues			100.00	100.00
CTC Revenues			77.04	-
O&M Costs			(75.00)	(75.00)
Debt Costs			(15.00)	(15.00)
Income Taxes			(34.81)	(4.00)
Equity Return (after-tax)		***$ 57.58***	***52.22***	***6.00***
Notes:				
1) All NPV's are computed as of the middle of Period 1.				
2) CTC Revenues are determined by the NPV of CTC Costs				
3) Income tax rate is 40 percent				

Example of Discounting Stranded Costs at After-Tax Cost of Equity				
	NPV1 @ 8%	*NPV1 @ 12%*	*Period 1*	*Period 2*
Earnings under Regulation				
O&M Costs			$ 75.00	$ 75.00
Debt Costs			$ 15.00	$ 15.00
Income Taxes			$ 20.00	$ 20.00
Equity Return (after-tax)		***$ 56.79***	***$ 30.00***	***$ 30.00***
Revenue Requirement			***$ 140.00***	***$ 140.00***
Stranded Cost/CTC at WACC				
Market Revenues			$ 100.00	$ 100.00
Stranded Costs		$ 75.71	$ 40.00	$ 40.00
CTC Revenues		$ 75.71	$ 75.71	
Earnings under Deregulation plus CTC				
Market Revenues			100.00	100.00
CTC Revenues			75.71	-
O&M Costs			(75.00)	(75.00)
Debt Costs			(15.00)	(15.00)
Income Taxes			(34.29)	(4.00)
Equity Return (after-tax)		***$ 56.79***	***51.43***	***6.00***
Notes:				
1) All NPV's are computed as of the middle of Period 1.				
2) CTC Revenues are determined by the NPV of CTC Costs				
3) Income tax rate is 40 percent				

Example of Discounting Stranded Costs at WACC -- Reverse Impact				
	NPV1 @ 8%	*NPV1 @ 12%*	***Period 1***	***Period 2***
Earnings under Regulation				
O&M Costs			$ 75.00	$ 60.00
Debt Costs			$ 15.00	$ 15.00
Income Taxes			$ 20.00	$ 20.00
Equity Return (after-tax)		*$ 56.79*	***$ 30.00***	***$ 30.00***
Revenue Requirement			***$ 140.00***	***$ 125.00***
Stranded Cost/CTC at WACC				
Market Revenues			$ 100.00	$ 140.00
Stranded Costs	$ 26.11		$ 40.00	$ (15.00)
CTC Revenues	$ 26.11		$ 26.11	
Earnings under Deregulation plus CTC				
Market Revenues			100.00	140.00
CTC Revenues			26.11	-
O&M Costs			(75.00)	(60.00)
Debt Costs			(15.00)	(15.00)
Income Taxes			(14.44)	(26.00)
Equity Return (after-tax)		***$ 56.49***	***21.67***	***39.00***
Notes:				
1) All NPV's are computed as of the middle of Period 1.				
2) CTC Revenues are determined by the NPV of CTC Costs				
3) Income tax rate is 40 percent				

Price Sufficiency for New Combined Cycle Capacity - Version 1

Inflation	2.50%	Fixed O&M (00 $/kW/year)	$ 5.28	Maintenance Capital	0.0%
Capacity (MW)	410.00	Variable O&M (00 $/MWh)	$ 2.16	Working Capital	0.0%
Capital Cost (00$/kW)	$ 595.00	Capacity Factor		Income Tax Rate	41.5%
Fuel Cost (96 $/mmbtu)	$ 2.25	Debt Cost	8.0%	Decommissioning	0.0%
Gas Transmission (96 $/mmbtu)	$ -	Debt Share	38.6%	Sources:	OCA-III-49, OCA-III-74, STJ-3, STJ-4, STJ-7, STJ-8
Heat Rate (btu/kWh)	7,000				Environmentalists-4-205, PPLICA-VIII-12

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2030	2034
Capacity Factor		53.5%	53.0%	62.0%	62.5%	66.0%	67.5%	72.0%	60.5%	72.5%	74.0%	73.0%	73.0%	73.0%	73.0%
Capacity Price ($/kW/year)		44.0	45.0	50.0	51.0	53.0	54.0	55.0	56.0	57.0	59.0	60.0	67.3	86.2	95.1
Energy Price ($/MWh)		26.0	27.0	29.0	30.0	31.0	32.0	32.0	33.0	35.0	35.0	36.0	40.8	52.3	57.7
Generation (GWh)		1,922	1,904	2,227	2,245	2,370	2,424	2,586	2,173	2,604	2,658	2,622	2,622	2,622	2,622
Capacity Revenues ($mm)		18.04	18.45	20.50	20.91	21.73	22.14	22.55	22.96	23.37	24.19	24.60	27.61	35.34	39.01
Energy Revenues ($mm)		49.96	51.40	64.58	67.34	73.48	77.58	82.75	71.71	91.14	93.02	94.39	107.08	137.07	151.30
Revenues		*68.00*	*69.85*	*85.08*	*88.25*	*95.21*	*99.72*	*105.30*	*94.67*	*114.51*	*117.21*	*118.99*	*134.69*	*172.41*	*190.31*
Fuel Costs ($/MWh)		18.27	18.72	19.19	19.67	20.16	20.67	21.18	21.71	22.25	22.81	23.38	26.45	33.86	37.38
Gas Transmission Cost ($/MWh)		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vble O&M Costs ($/MWh)		2.33	2.39	2.44	2.51	2.57	2.63	2.70	2.77	2.84	2.91	2.98	3.37	4.31	4.76
Fixed O&M Costs ($/kW/year)		5.69	5.83	5.98	6.13	6.28	6.44	6.60	6.76	6.93	7.10	7.28	8.24	10.55	11.64
Fuel Costs ($mm)		35.10	35.64	42.73	44.15	47.79	50.10	54.78	47.18	57.95	60.63	61.30	69.36	88.78	98.00
Variable O&M Costs ($mm)		4.47	4.54	5.44	5.63	6.09	6.38	6.98	6.01	7.38	7.72	7.81	8.84	11.31	12.48
Fixed O&M Costs ($mm)		2.33	2.39	2.45	2.51	2.57	2.64	2.70	2.77	2.84	2.91	2.99	3.38	4.32	4.77
Total Operating Costs ($mm)		*41.90*	*42.57*	*50.63*	*52.29*	*56.45*	*59.12*	*64.46*	*55.96*	*68.17*	*71.26*	*72.10*	*81.57*	*104.42*	*115.26*
Depreciation ($mm)		9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20
Interest ($mm)		8.52	8.24	7.95	7.67	7.39	7.10	6.82	6.53	6.25	5.97	5.68	4.26	1.42	0.28
Income Taxes ($mm)		3.48	4.08	7.18	7.92	9.20	10.08	10.30	9.53	12.81	12.77	13.28	16.45	23.81	27.21
Net Income		4.90	5.76	10.12	11.17	12.97	14.21	14.52	13.44	18.07	18.01	18.73	23.20	33.57	38.36
Capital Expenditures	(276.01)	-	-	-	-	-	-	-	-	-	-	-	-		
EOY Book Value	276.01	266.81	257.61	248.41	239.21	230.01	220.81	211.61	202.41	193.20	184.00	174.80	128.80	36.80	(0.00)
EOY Debt	106.54	102.99	99.44	95.88	92.33	88.78	85.23	81.68	78.13	74.58	71.03	67.47	49.72	14.21	(0.00)
Working Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash Flow															
Net Income		4.90	5.76	10.12	11.17	12.97	14.21	14.52	13.44	18.07	18.01	18.73	23.20	33.57	38.36
Depreciation		9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20
Capital Expenditures	(276.01)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Cash Flow	106.54	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)	(3.55)
Working Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Flow	(169.47)	10.55	11.40	15.77	16.82	18.62	19.86	20.17	19.09	23.72	23.66	24.38	28.85	39.21	44.01
Internal Rate of Return	11.8%														
NPV @ 12.5%	($9.59)														

Note: Some columns are hidden for reporting purposes.

Price Sufficiency for New Combined Cycle Capacity -- Version 2

Inflation	2.50%	Fixed O&M (00 $/kW/year)	$ 5.28	Maintenance Capital	3.0%	of book value
Capacity (MW)	*410.00*	*Variable O&M (00 $/MWh)*	*$ 2.16*	*Working Capital*	*5.0%*	*of revenues*
Capital Cost (00$/kW)	*$ 595.00*	Capacity Factor	70.0%	Income Tax Rate	41.5%	
Wellhead Fuel Cost (96 $/mmbtu)	$ 2.25	Debt Cost	8.0%	Decommissioning	10.0%	of investment cost
Gas Transmission (96 $/mmbtu)	$ 0.50	Debt Share	38.6%	Sources:	OCA-III-49, OCA-III-74, STJ-3, STJ-4, STJ-7, STJ-8, JRS-1	
Heat Rate (btu/kWh)	7,000				Environmentalists-4-205, UGI-Gas XD tariff, JMK-2, PPL:ICA-VIII-12	

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2030	2034
Capacity Factor		53.5%	53.0%	62.0%	62.5%	66.0%	67.5%	72.0%	60.5%	72.5%	74.0%	73.0%	73.0%	73.0%	73.0%
Capacity Price ($/kW/year)		44.0	45.0	50.0	51.0	53.0	54.0	55.0	56.0	57.0	59.0	60.0	67.3	86.2	95.1
Energy Price ($/MWh)		26.0	27.0	29.0	30.0	31.0	32.0	32.0	33.0	35.0	35.0	36.0	40.8	52.3	57.7
Generation (GWh)		1,922	1,904	2,227	2,245	2,370	2,424	2,586	2,173	2,604	2,658	2,622	2,622	2,622	2,622
Capacity Revenues ($mm)		*18.04*	*18.45*	*20.50*	*20.91*	*21.73*	*22.14*	*22.55*	*22.96*	*23.37*	*24.19*	*24.60*	*27.61*	*35.34*	*39.01*
Energy Revenues ($mm)		49.96	51.40	64.58	67.34	73.48	77.58	82.75	71.71	91.14	93.02	94.39	107.08	137.07	151.30
Revenues		***68.00***	***69.85***	***85.08***	***88.25***	***95.21***	***99.72***	***105.30***	***94.67***	***114.51***	***117.21***	***118.99***	***134.69***	***172.41***	***190.31***
Fuel Costs ($/MWh)		18.27	18.72	19.19	19.67	20.16	20.67	21.18	21.71	22.25	22.81	23.38	26.45	33.86	37.38
Gas Transmission Cost ($/MWh)		4.37	4.48	4.59	4.71	4.82	4.95	5.07	5.20	5.33	5.46	5.60	6.33	8.10	8.94
Vble O&M Costs ($/MWh)		2.33	2.39	2.44	2.51	2.57	2.63	2.70	2.77	2.84	2.91	2.98	3.37	4.31	4.76
Fixed O&M Costs ($/kW/year)		5.69	5.83	5.98	6.13	6.28	6.44	6.60	6.76	6.93	7.10	7.28	8.24	10.55	11.64
Fuel Costs ($mm)		43.50	44.17	52.96	54.72	59.23	62.09	67.88	58.47	71.82	75.13	75.97	85.96	110.03	121.45
Variable O&M Costs ($mm)		4.47	4.54	5.44	5.63	6.09	6.38	6.98	6.01	7.38	7.72	7.81	8.84	11.31	12.48
Fixed O&M Costs ($mm)		2.33	2.39	2.45	2.51	2.57	2.64	2.70	2.77	2.84	2.91	2.99	3.38	4.32	4.77
Decommissioning															57.89
Total Operating Costs ($mm)		***50.30***	***51.10***	***60.85***	***62.86***	***67.89***	***71.11***	***77.57***	***67.25***	***82.04***	***85.77***	***86.77***	***98.17***	***125.66***	***196.60***
Depreciation ($mm)		9.48	9.48	9.49	9.50	9.51	9.52	9.54	9.55	9.56	9.58	9.59	9.70	9.20	9.20
Interest ($mm)		8.52	8.49	8.45	8.41	8.37	8.32	8.28	8.23	8.19	8.14	8.08	7.79	6.60	5.46
Income Taxes ($mm)		(0.12)	0.32	2.61	3.11	3.92	4.46	4.12	4.00	6.11	5.70	6.03	7.89	12.84	(8.70)
Net Income		(0.17)	0.46	3.68	4.38	5.52	6.30	5.80	5.64	8.61	8.03	8.51	11.13	18.11	(12.26)
Capital Expenditures	(276.01)	(8.28)	(8.24)	(8.21)	(8.17)	(8.13)	(8.09)	(8.04)	(8.00)	(7.95)	(7.90)	(7.85)	(7.57)		
EOY Book Value	276.01	274.81	273.57	272.28	270.95	269.57	268.13	266.64	265.09	263.48	261.81	260.07	250.24	204.48	167.68
EOY Debt	106.54	106.08	105.60	105.10	104.59	104.05	103.50	102.92	102.32	101.70	101.06	100.39	96.59	78.93	64.72
Working Capital		3.40	3.49	4.25	4.41	4.76	4.99	5.27	4.73	5.73	5.86	5.95	6.73	8.62	9.52
Cash Flow															
Net Income		(0.17)	0.46	3.68	4.38	5.52	6.30	5.80	5.64	8.61	8.03	8.51	11.13	18.11	(12.26)
Depreciation		9.48	9.48	9.49	9.50	9.51	9.52	9.54	9.55	9.56	9.58	9.59	9.70	9.20	9.20
Capital Expenditures	(276.01)	(8.28)	(8.24)	(8.21)	(8.17)	(8.13)	(8.09)	(8.04)	(8.00)	(7.95)	(7.90)	(7.85)	(7.57)	-	-
Debt Cash Flow	106.54	(0.46)	(0.48)	(0.50)	(0.52)	(0.53)	(0.55)	(0.58)	(0.60)	(0.62)	(0.65)	(0.67)	(0.82)	(3.55)	(3.55)
Working Capital		(3.40)	(0.09)	(0.76)	(0.16)	(0.35)	(0.23)	(0.28)	0.53	(0.99)	(0.14)	(0.09)	(0.16)	7.08	7.81
Net Cash Flow	(169.47)	(2.84)	1.12	3.70	5.04	6.03	6.95	6.44	7.12	8.61	8.92	9.49	12.27	30.83	1.20
Internal Rate of Return	4.7%														
NPV @ 12.5%	($102.77)														

Note: Some columns are hidden for reporting purposes.

Summary of CTC Revenues by Class							
Revenues	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
RS	338.41	308.16	267.78	229.98	223.85	216.48	223.73
GS-1	64.04	61.11	56.31	51.96	51.20	49.16	50.14
GS-3	251.85	234.69	209.36	185.41	180.55	175.82	181.50
LP-4	133.57	124.09	109.95	97.88	93.93	94.98	91.15
LP-5	74.56	69.59	62.31	56.37	54.24	52.07	52.27
LP-6	13.81	12.75	11.24	10.08	9.58	9.05	8.96
IST	28.77	26.31	22.62	21.18	18.98	16.66	15.33
Other	44.26	41.00	36.50	33.66	31.78	29.69	29.16
Total	949.27	877.70	776.06	686.53	664.09	643.91	652.25
GWh							
RS	11,632.5	11,710.5	11,819.4	11,957.0	12,084.3	12,221.8	12,359.4
GS-1	1,535.5	1,574.5	1,613.6	1,656.9	1,694.6	1,656.9	1,656.9
GS-3 (1)	7,190.5	7,190.5	7,190.5	7,190.5	7,190.5	7,190.5	7,190.5
LP-4	4,468.9	4,543.1	4,616.8	4,695.3	4,769.5	4,847.5	4,925.6
LP-5	2,651.5	2,695.5	2,739.2	2,785.8	2,829.8	2,876.1	2,922.4
LP-6	576.0	585.6	595.1	605.2	614.8	624.8	634.9
IST	2,327.7	2,366.3	2,404.7	2,445.6	2,484.3	2,524.9	2,565.6
Cents/kWh							
RS	2.91	2.63	2.27	1.92	1.85	1.77	1.81
GS-1	4.17	3.88	3.49	3.14	3.02	2.97	3.03
GS-3	3.50	3.26	2.91	2.58	2.51	2.45	2.52
LP-4	2.99	2.73	2.38	2.08	1.97	1.96	1.85
LP-5	2.81	2.58	2.27	2.02	1.92	1.81	1.79
LP-6	2.40	2.18	1.89	1.67	1.56	1.45	1.41
IST	1.24	1.11	0.94	0.87	0.76	0.66	0.60
(1) Uses the GWh reported for CTC revenue determination, not other revenue determination.							
Source: OCA-III-39							

GS-1 CTC Revenues by Load Factor						
PP&L Proposed 2002 Levels						
	Load	*Billing*	*Demand*	*Energy*	*Per kWh*	*Per kWh*
kWh/kW	*Factor*	*Demand*	*Charge*	*Charge*	*Energy*	*CTC*
50.00	6.8%	12.0	$ (16.10)	$ 13.35	0.0222	(0.0046)
100.00	13.7%	12.0	$ (16.10)	$ 26.70	0.0222	0.0088
150.00	20.5%	12.0	$ (16.10)	$ 40.05	0.0222	0.0133
200.00	27.4%	12.0	$ (16.10)	$ 45.75	0.0191	0.0124
250.00	34.2%	12.0	$ (16.10)	$ 51.46	0.0172	0.0118
300.00	41.1%	12.0	$ (16.10)	$ 57.17	0.0159	0.0114
350.00	47.9%	12.0	$ (16.10)	$ 62.87	0.0150	0.0111
400.00	54.8%	12.0	$ (16.10)	$ 68.58	0.0143	0.0109
450.00	61.6%	12.0	$ (16.10)	$ 74.28	0.0138	0.0108
500.00	68.5%	12.0	$ (16.10)	$ 79.99	0.0133	0.0106
550.00	75.3%	12.0	$ (16.10)	$ 85.70	0.0130	0.0105
600.00	82.2%	12.0	$ (16.10)	$ 91.40	0.0127	0.0105
650.00	89.0%	12.0	$ (16.10)	$ 97.11	0.0124	0.0104
700.00	95.9%	12.0	$ (16.10)	$ 102.81	0.0122	0.0103
	CTC Energy Charge (1)		2.22	cents per kWh		
	CTC Energy Charge (2)		0.95	cents per kWh		
	CTC Demand Charge		(2.30)	$ per kW over 5 kW		

Pennsylvania Power & Light Company			
Rate Schedule GS-1			
Small General Service at Secondary Voltage			
Calculation of Effect of Proposed Rate			
Based on Bill Frequency Distribution of 12 months ended December 1996			
1999 -- MAINTAIN DEMAND CHARGE FOR DELIVERY SERVICE			
PRESENT RATE	**UNITS**	**RATE**	**REVENUE**
MONTHLY			
Total Bills	*1,461,726*	*$ 7.48*	*10,933,710*
BILLING KW BLOCKS			
First 5 kW	7,308,630	-	-
Excess kW	4,425,997	$ 2.00	8,851,994
Sub-Total	*11,734,627*		*8,851,994*
KWH BLOCKS			
First 150 kWh/kW	1,048,678,199	0.10436	109,440,057
Excess kWh	379,310,783	0.07841	29,741,758
Sub-Total	*1,427,988,982*		*139,181,815*
TOTAL (excl. G1V, G1C)			**158,967,520**
PROPOSED RATES	**UNITS**	**RATE**	**REVENUE**
MONTHLY			
Total Bills	*1,461,726*	*$ 7.48*	*10,933,710*
BILLING KW BLOCKS			
First 5 kW	7,308,630	-	-
Excess kW	4,425,997	$ 2.00	8,851,994
Sub-Total	*11,734,627*		*8,851,994*
DELIVERY KWH BLOCKS			
First 150 kWh/kW	1,048,678,199	0.02484	26,050,296
Excess kWh	379,310,783	0.02484	9,422,488
Sub-Total	*1,427,988,982*		*35,472,784*
COMPETITIVE TRANSITION CHARGE			
Customer-Specific Fixed Charge			30,459,672
First 150 kWh/kW	1,048,678,199	0.02373	24,889,697
Excess kWh	379,310,783	0.01468	5,569,975
Sub-Total	*1,427,988,982*		*60,919,344*
MARKET RATES			
First 150 kWh/kW	1,048,678,199	0.03205	33,610,367
Excess kWh	379,310,783	0.02420	9,179,321
Sub-Total	*1,427,988,982*	*0.02996*	*42,789,688*
TOTAL (excl. G1V, G1C)			**158,967,520**

Pennsylvania Power & Light Company			
Rate Schedule GS-1			
Small General Service at Secondary Voltage			
Calculation of Effect of Proposed Rate			
Based on Bill Frequency Distribution of 12 months ended December 1996			
1999 -- MAINTAIN BLOCK STRUCTURE IN DELIVERY CHARGE			
PRESENT RATE	**UNITS**	**RATE**	**REVENUE**
MONTHLY			
Total Bills	*1,461,726*	*$ 7.48*	*10,933,710*
BILLING KW BLOCKS			
First 5 kW	7,308,630	-	-
Excess kW	4,425,997	$ 2.00	8,851,994
Sub-Total	***11,734,627***		***8,851,994***
KWH BLOCKS			
First 150 kWh/kW	1,048,678,199	0.10436	109,440,057
Excess kWh	379,310,783	0.07841	29,741,758
Sub-Total	***1,427,988,982***		***139,181,815***
TOTAL (excl. G1V, G1C)			**158,967,520**
PROPOSED RATES	**UNITS**	**RATE**	**REVENUE**
MONTHLY			
Total Bills	*1,461,726*	*$ 7.48*	*10,933,710*
BILLING KW BLOCKS			
First 5 kW	7,308,630	-	-
Excess kW	4,425,997	$ 2.00	8,851,994
Sub-Total	***11,734,627***		***8,851,994***
DELIVERY KWH BLOCKS			
First 150 kWh/kW	1,048,678,199	0.02661	27,905,704
Excess kWh	379,310,783	0.01995	7,567,080
Sub-Total	***1,427,988,982***		***35,472,784***
COMPETITIVE TRANSITION CHARGE			
Customer-Specific Fixed Charge			30,459,672
First 150 kWh/kW	1,048,678,199	0.02285	23,961,993
Excess kWh	379,310,783	0.01713	6,497,679
Sub-Total	***1,427,988,982***		***60,919,344***
MARKET RATES			
First 150 kWh/kW	1,048,678,199	0.03205	33,610,367
Excess kWh	379,310,783	0.02420	9,179,321
Sub-Total	***1,427,988,982***	***0.02996***	***42,789,688***
TOTAL (excl. G1V, G1C)			**158,967,520**
			0.000%

Pennsylvania Power & Light Company			
Rate Schedule GS-3			
Small General Service at Secondary Voltage			
Calculation of Effect of Proposed Rate			
Based on Bill Frequency Distribution of 12 months ended December 1996			
1999 -- MAINTAIN BLOCK STRUCTURE IN DELIVERY CHARGE			
PRESENT RATE	**UNITS**	**RATE**	**REVENUE**
BILLING KW BLOCKS			
All kW	*20,778,289*	$ 6.94	*144,201,326*
KWH BLOCKS			
First 200 kWh/kW	4,015,514,457	0.06444	258,759,752
Next 200 kWh/kW	2,483,030,742	0.05047	125,318,562
Excess kWh	691,976,710	0.04849	33,553,951
Sub-Total	***7,190,521,909***		***417,632,264***
TOTAL (excl. TOD, G3V, G3C)			**561,833,589**
PROPOSED RATES			
DELIVERY CHARGES			
First 200 kWh/kW	4,015,514,457	0.01708	68,568,031
Next 200 kWh/kW	2,483,030,742	0.01115	27,694,528
Excess kWh	691,976,710	0.01031	7,137,146
Sub-Total	***7,190,521,909***		***103,399,705***
COMPETITIVE TRANSITION CHARGE			
Customer-Specific Fixed Charge			122,408,280
All kW	20,778,289	2.51	52,153,505
First 200 kWh/kW	4,015,514,457	0.01160	46,588,446
Next 200 kWh/kW	2,483,030,742	0.00758	18,817,005
Excess kWh	691,976,710	0.00701	4,849,323
Sub-Total	***7,190,521,909***		***244,816,560***
MARKET RATES			
All kW	20,778,289	$ 1.92	39,894,315
All kWh	7,190,521,909	0.02416	173,723,009
Sub-Total			***213,617,324***
TOTAL (excl. TOD, G3V, G3C)			**561,833,589**
			0.000%

EXHIBIT RDK-3

PP&L INTERROGATORY RESPONSES

OCA-III-39 (summary page only)
OSBA-I-36
OSBA-I-35
OCA-III-77
OSBA-I-27
OSBA-I-24
OSBA-I-18
OSBA-I-33
PPLICA-VII-1
OSBA-I-4
OSBA-I-11
OSBA-I-41
OCA-VI-17

2 July 1997

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

Docket No. R-00973954

Q.39 Please show the projected CTC revenues for each year of the transition period, including class-specific revenues and projected billing determinants (customer, energy and demand as appropriate).

A.39 See response to Question OCA-Set II-42 of Interrogatories of the Office of Consumer Advocate dated April 16, 1997 explaining revisions to affecting the calculation of CTC revenues.

See Attachment 1.

OCA-SET III
Question 39

ATTACHMENT 1

Total CTC Revenue

Year	1999	2000	2001	2002	2003	2004	2005
RS	$ 338,412,374	$ 308,162,832	$ 267,777,770	$ 229,983,247	$ 223,845,712	$ 216,481,603	$ 223,728,666
RWO	$ (35,312)	$ (47,959)	$ (64,631)	$ (80,206)	$ (83,403)	$ (87,057)	$ (85,230)
RW1	$ 40,221	$ 34,803	$ 27,661	$ 20,988	$ 19,618	$ 18,053	$ 18,836
RTD	$ 128,545	$ 117,748	$ 102,954	$ 91,582	$ 88,284	$ 84,343	$ 85,062
RTS	$ 5,567,663	$ 5,168,749	$ 4,675,205	$ 4,569,643	$ 4,297,316	$ 3,881,579	$ 3,593,380
GS-1	$ 64,044,987	$ 61,113,323	$ 56,311,162	$ 51,957,018	$ 51,196,335	$ 49,160,171	$ 50,139,702
G1V	$ 479,413	$ 430,892	$ 366,113	$ 305,490	$ 295,646	$ 283,833	$ 295,458
G1C	$ (71,647)	$ (78,293)	$ (88,209)	$ (92,458)	$ (101,517)	$ (110,445)	$ (115,828)
GS-3	$ 251,847,586	$ 234,689,434	$ 209,355,345	$ 185,410,648	$ 180,548,972	$ 175,819,243	$ 181,504,708
G3C	$ 264,150	$ 238,244	$ 194,728	$ 176,891	$ 147,925	$ 120,030	$ 110,327
G3V	$ 89,949	$ 80,242	$ 67,283	$ 55,155	$ 53,186	$ 50,823	$ 53,148
LP-4	$ 133,566,190	$ 124,086,050	$ 109,945,912	$ 97,884,719	$ 93,926,850	$ 94,978,646	$ 91,145,578
L4C	$ 14,240	$ 12,522	$ 9,506	$ 9,361	$ 6,651	$ 6,707	$ 2,361
LP-5	$ 74,557,075	$ 69,590,249	$ 62,314,146	$ 56,379,112	$ 54,243,728	$ 52,070,916	$ 52,272,564
LP-6	$ 13,808,243	$ 12,749,413	$ 11,243,479	$ 10,078,531	$ 9,577,550	$ 9,048,223	$ 8,962,048
LPEP	$ 2,687,648	$ 2,513,343	$ 2,283,802	$ 2,072,474	$ 2,021,909	$ 1,968,624	$ 1,995,936
ISP	$ 7,228,598	$ 6,687,289	$ 5,853,297	$ 5,442,821	$ 4,990,479	$ 4,528,445	$ 4,335,659
IST	$ 28,773,783	$ 26,308,226	$ 22,617,357	$ 21,183,259	$ 18,977,763	$ 16,658,839	$ 15,333,019
ISM	$ 7,230,012	$ 6,712,990	$ 5,963,856	$ 5,776,060	$ 5,206,836	$ 4,644,020	$ 4,360,620
IS1	$ 29,009	$ 23,211	$ 14,345	$ 11,089	$ 7,675	$ 4,296	$ (1,142)
GH-2(R)	$ 3,493,583	$ 3,296,978	$ 3,022,701	$ 2,781,597	$ 2,705,544	$ 2,629,491	$ 2,665,900
GH-1(R)	$ 14,096,310	$ 13,049,550	$ 11,609,594	$ 10,292,225	$ 9,923,474	$ 9,567,000	$ 9,778,299
BL	$ 147,580	$ 138,742	$ 126,531	$ 118,168	$ 131,425	$ 107,905	$ 123,395
St.Lt.	$ 2,868,421	$ 2,622,313	$ 2,331,325	$ 2,101,598	$ 2,066,591	$ 1,994,391	$ 1,945,164
Total	$ 949,268,621	$ 877,700,891	$ 776,061,232	$ 686,529,012	$ 664,094,549	$ 643,909,679	$ 652,247,630

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.36. With respect to stranded nuclear costs:

a. Please provide any economic or financial analyses performed by PP&L of the implications of shutting down either or both of the Susquehanna units prior to the end of their useful life.

b. Please provide a detailed cash flow forecast (in hardcopy and electronic spreadsheet format) for the Susquehanna plant (both units) for its remaining life showing:

i. Market price revenues;
ii. Revenues from stranded cost recovery;
iii. Any other cash revenues;
iv. Cash fuel expenditures;
v. Cash O&M expenditures;
vi. Capital expenditures;
vii. Cash decommissioning expenditures;
viii. Changes in working capital;
ix. Any other cash shutdown costs;
x. Cash tax effects, for both operating and shutdown periods.

c. Please provide a detailed cash flow forecast for the Susquehanna plant under the assumption that the plant closes at 1 January 1999 (or the earliest technically feasible opportunity) showing:

i. Market price revenues;
ii. Revenues from stranded cost recovery;
iii. Any other cash revenues;
iv. Cash fuel expenditures;
v. Cash O&M expenditures;
vi. Capital expenditures;
vii. Cash decommissioning expenditures;
viii. Changes in working capital;
ix. Any other cash shutdown costs;
x. Cash tax effects, for both operating and shutdown periods.

A.36. a. The Company has not performed any economic or financial analysis on the implications of shutting down either or both of the Susquehanna units prior to the end of their useful life.

b. i. See Exhibit JRS 1.

ii The Company's filing supports a claim for recovery of $4.6 billion of stranded cost. Of that amount, approximately $4 billion can be collected under the rate cap. The Company did not provide any separate calculations for the amount of nuclear revenues to be collected under the rate cap.

iii.-x. See response to item b.(i).

c. i.-x. As the response to item a. indicates, the Company has not performed any economic or financial analysis of an early shutdown of the Susquehanna plant and as a result cannot do a detailed cash flow analysis under the assumption that the plant closes in 1999.

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.35. With respect to your selection of a discount rate for stranded cost calculation:

a. Please confirm that the discount rate you have chosen (7.92 percent) is PP&L's estimate of its after-tax weighted average cost of capital. If you cannot confirm, please explain your response.

b. Please provide all of your reasons, including relevant citations from financial texts (e.g., Brealey & Myers) for your choice of discount rate.

c. Do you agree with the following statement: 'A CTC should be developed such that the expected net present value of after-tax income to PP&L's shareholders earned by pricing at market rates plus a CTC should be no greater than the expected net present value of after-tax income that PP&L's shareholders would have earned under regulation.' To the extent that you disagree, please explain your response.

d. Do you agree with the following statement: 'A CTC should be developed such that the expected net present value of after-tax income to PP&L's shareholders earned by pricing at market rates plus a CTC should be approximately equal to the expected net present value of after-tax income that PP&L's shareholders would have earned under regulation.' To the extent that you disagree, please explain your response.

e. Do you agree that after-tax income and after-tax cash flows to equity holders should be discounted at the after-tax cost of equity? To the extent that you disagree, please explain your response and cite all authorities that support your position.

A.35. a. Yes. See the Direct Testimony of Joseph R. Schadt (Statement No. 8), page 30, lines 16 and 20 and Exhibit JRS 1.

b. The reasoning associated with the choice of the after-tax weighted average cost of capital can be found in the financial text Principles of Corporate Finance, fourth edition, by Brealey & Myers. Attachment 1 is a copy of pages 465 to 476 from that text.

c. This statement is incorrect. Initially, it must be recognized that PP&L does not differentiate cash flows by source of funding. The statement might be correct in conceptual terms if it related to such total after-tax cash flows, rather than income. Although in theory, the sum of the total after-tax cash flows derived by PP&L from the market price of energy sold from PP&L's generating plants plus the CTC to be received from customers should equal the total after-tax cash flows that would have been realized under continuing cost-of-service regulation (both stated as their net present value as of January 1, 1999), the reality is that the two situations may not be equal for the following reasons. First, total generation revenue (CTC plus generation market revenue) will be limited by the rate cap under Section 2804 of the Electricity Generation Customer Choice and Competition Act ("Act"). Absent this provision of the Act, costs associated with generation that would cause regulated rates to exceed the levels allowed under the rate cap would be recoverable. Second, although there will be a reconciliation (i.e., true-up) for variations in sales associated with the projections used to calculate the CTC, there will be no true-up for actual prices obtained by PP&L in a competitive market for electricity versus the projections of those prices in this proceeding. Third, the only costs recoverable in the CTC are those that can be predicted in this proceeding. Any costs associated with generation that have not been predicted can be recovered in the future only if the competitive market price is high enough to cover those costs.

d. No. See the response to item c.

e. Although PP&L does not utilize the methodology implied by the question (see the response to item c), PP&L does believe that the after-tax cash flows to equity holders should be discounted at the investor-required cost of equity.

ATTACHMENT 1

PRINCIPLES OF CORPORATE FINANCE

FOURTH EDITION

Richard A. Brealey
Professor of Corporate Finance
London Business School

Stewart C. Myers
Gordon Y Billard Professor of Finance
Sloan School of Management
Massachusetts Institute of Technology

McGraw-Hill, Inc.
New York St. Louis San Francisco Auckland Bogotá
Caracas Lisbon London Madrid Mexico City Milan
Montreal New Delhi San Juan Singapore
Sydney Tokyo Toronto

19-3 THE WEIGHTED-AVERAGE-COST-OF-CAPITAL FORMULA

Bear with us; we have still another formula. This one does not require an estimate of T^*, the *net* tax advantage of corporate borrowing, but only T_c, the marginal tax rate. Unfortunately, the formula applies to the firm as a whole, not necessarily to any specific project.

We refer to the *weighted-average cost of capital*. Sometimes we call it the *textbook formula*, since many other textbooks have put heavy emphasis on it. The formula is[11]

$$r^* = r_D(1 - T_c)\frac{D}{V} + r_E\frac{E}{V}$$

where r^* = the adjusted cost of capital
r_D = the firm's current borrowing rate
T_c = the marginal *corporate* income tax rate—*not* the effective rate T^* used in Sections 19-1 and 19-2
r_E = the expected rate of return on the firm's stock (which depends on the firm's business risk *and* its debt ratio)
D, E = the market values of currently outstanding debt and equity
$V = D + E$ = the total market value of the firm

The first thing to notice about the weighted-average formula is that all variables in it refer to the firm as a whole. As a result the formula gives the right discount rate only for projects that are just like the firm undertaking them. The formula works for the "average" project. It is incorrect for projects that are safer or riskier than the average of the firm's existing assets. It is incorrect for projects whose acceptance would lead to an increase or decrease in the firm's debt ratio.

The idea behind the weighted-average formula is simple and intuitively appealing. If the new project is profitable enough to pay the (after-tax) interest on the debt used to finance it, and also to generate a superior expected rate of return on the equity invested in it, then it must be a good project. What is a "superior" equity return? One that exceeds r_E, the expected rate of return required by investors in the firm's shares. Let us see how this idea leads to the weighted-average formula.

Suppose that the firm invests in a new project which is expected to produce the same yearly income in perpetuity. If the firm maintains its debt ratio, the amount of debt used to finance the project is

$$\text{Firm's debt ratio} \times \text{investment} = \frac{D}{V} \times \text{investment}$$

Similarly, the equity used to finance the project is

$$\text{Firm's equity ratio} \times \text{investment} = \frac{E}{V} \times \text{investment}$$

[11] If $T_c = 0$, the weighted-average cost of capital simplifies to

$$r_D\frac{D}{V} + r_E\frac{E}{V}$$

This is exactly the formula that we introduced in Chapter 17, where we ignored taxes. As we pointed out in that chapter, MM's proposition I implies that this weighted average is independent of the debt ratio D/V. If MM's proposition fails because of market imperfections, the firm can try to seek the debt ratio D/V which minimizes r^*. See Chapter 17, Section 17-3.

If the project is worthwhile, the income must cover after-tax interest charges and provide an acceptable return to equityholders. The after-tax interest costs on the additional debt are equal to

$$\text{After-tax interest rate} \times \text{value of debt} = r_D(1 - T_c) \times \frac{D}{V} \times \text{investment}$$

The minimum acceptable income to equityholders is

$$\text{Expected return on equity} \times \text{value of equity} = r_E \times \frac{E}{V} \times \text{investment}$$

Therefore, for the project to be acceptable, its income *must exceed:*

$$r_D(1 - T_c) \times \frac{D}{V} \times \text{investment} + r_E \times \frac{E}{V} \times \text{investment}$$

This brings us back to the weighted-average formula. Just divide through by the initial investment:

$$\frac{\text{Income}}{\text{Investment}} \textit{ must exceed } r_D(1 - T_c)\frac{D}{V} + r_E\frac{E}{V}$$

Note that the ratio of the project's annual income to investment is just the project's return. Therefore our formula gives the minimum acceptable rate of return from the project.

We have derived the textbook formula only for firms and projects offering perpetual cash flows. But Miles and Ezzell have shown that the formula works for any cash-flow pattern if the firm adjusts its borrowing to maintain a constant debt ratio D/V, regardless of whether things turn out well or poorly. When the firm departs from this policy, the textbook formula is only approximately correct.

Now We Apply the Textbook Formula to the Geothermal Project

Imagine the geothermal project set up as an independent, one-asset firm which we'll call Geothermal, Inc. Once the project is built, Geothermal's market value will be worth the initial investment of $1,000,000 plus the project's APV.

In Section 19-2, we calculated that if Geothermal maintains a constant debt ratio of 40 percent, the APV is $222,200. Thus Geothermal's balance sheet should turn out as follows:

Geothermal, Inc.
(market values)

Assets (initial investment + APV)	1,222,200	488,900	Debt (D) (40% of firm value)
		733,300	Equity (E) (60% of firm value)
	1,222,200	1,222,200	

Each year the equityholders expect to receive the cash flow from the investment (C) *less* the interest payment on debt ($r_D D$) *plus* the interest tax shield ($T_c r_D D$):

$$\text{Expected equity income} = C - r_D D + T_c r_D D$$
$$= 213{,}300 - .14(433{,}300) + .34(.14)(433{,}300)$$
$$= 174{,}300$$

The expected rate of return on equity is equal to the expected equity income divided by the equity value:

$$\text{Expected equity return} = r_E = \frac{\text{expected equity income}}{\text{equity value}}$$
$$= \frac{174{,}300}{731{,}300} = .238, \text{ or } 23.8\%$$

Now suppose Geothermal unexpectedly encounters another investment opportunity. The second is a clone of the first in all dimensions save profitability: It has the same business risk and the same time pattern of cash flows. Geothermal therefore plans to borrow 40 percent of the project's value.

If management has forgotten the calculations we did in Section 19-2, it can use the textbook formula to find the appropriate adjusted discount rate.

$$r^* = r_D(1 - T_c)\frac{D}{V} + r_E\frac{E}{V}$$
$$= .14(1 - .34)(.4) + .238(.6)$$
$$= .18, \text{ or } 18\%$$

That's exactly the same figure that we got earlier, using the Miles and Ezzell formula.

Using the Textbook Formula

One of the handy features of the textbook formula is that you can often use stock market data to get an estimate of r_E, the expected rate of return demanded by investors in the company's stock. With that estimate, the textbook r^* is not too hard to calculate, because the borrowing rate r_D and the debt and equity ratios D/V and E/V can be directly observed or estimated without too much trouble.[12]

The textbook r^* is a *company* adjusted cost of capital. Strictly speaking, it works only for projects that are carbon copies of the firm's existing assets, in both business risk and financing. Often it is used as a companywide benchmark discount rate: the benchmark is adjusted upward for unusually risky projects and downward for unusually safe ones.

You can also calculate the textbook r^* for *industries*. Suppose that a pharmaceutical company has a subsidiary which produces specialty chemicals. What discount rate is better for the subsidiary's projects—the company r^* or a weighted-average cost of capital for a portfolio of "pure play" specialty chemical companies? The latter rate is better in principle, and also in practice if good data are available for firms with operations and markets similar to the subsidiary's.

POOR ORIGINAL

[12] Most corporate debt is not actively traded, so its market value cannot be observed directly. But you can usually value a nontraded debt security by looking to securities which *are* traded and which have approximately the same default risk and maturity. See Chapter 23.

For healthy firms the market value of debt is usually not too far from book value, so many managers and analysts use book value for D in the weighted-average cost-of-capital formula. However, be sure to use *market*, not book, values for E.

An Application to the Railroad Industry

In mid-1974 the assets of the Penn Central Railroad were taken over by Conrail, a new, federally sponsored corporation. Since Penn Central had declared bankruptcy in 1971, the assets taken by Conrail really belonged to the railroad's creditors. Congress set up a special court to determine fair compensation.

Although the Penn Central system was generating hair-curling losses overall, some of its freight lines were potentially profitable. In 1978 one of the authors was asked to estimate a discount rate for valuing the cash flows these lines would have produced, had Conrail not taken them over. He was asked to assume that these freight lines had the same business risk and financing as the railroad industry generally. That sounded like a job for the textbook formula. An extensive investigation boiled down to the following calculation:

$$\begin{aligned} r^*(\text{in mid-1974}) &= r_D(1 - T_c)\frac{D}{V} + \frac{r_E E}{V} \\ &= .087(1 - .5)(.45) + .16(.55) \\ &= .1076, \text{ or about } 10\tfrac{3}{4}\% \end{aligned}$$

The formula's components were derived as follows:

- r_D = .087, a weighted average of bond yields for 10 major railroads in mid-1974
- T_c = .50. The corporate income tax rate in mid-1974 was 48 percent. Two percentage points were added to cover state income taxes.
- D/V = .45. The estimated average market debt-to-value ratio for 10 major railroads. Thus $E/V = .55$.
- r_E = .16. Railroad stocks on average appeared to have about the same risk as the market portfolio. Their betas averaged out close to 1.0. Thus $r_E = r_m$. The 16 percent market return equals the sum of the Treasury bill yield in mid-1974 plus the historical risk premium on the market portfolio.

Of course each of these numbers was to some extent controversial. Other expert witnesses used the same textbook formula to arrive at substantially different answers. Anyone brave enough to estimate a discount rate in public can expect controversy.

*A Note on Asset Betas and the Weighted-Average Cost of Capital

The weighted-average cost of capital popped up first in Chapter 9, where we showed how the capital asset pricing model can be used to estimate the company cost of capital. In fact, we proposed two estimation methods:

Method 1

Step 1. Plug the equity beta into the capital asset pricing model formula to give the expected return on equity.

Step 2. Calculate a weighted average of the expected returns on the debt and equity:

$$r_{\text{assets}} = r_{\text{debt}}\frac{D}{V} + r_{\text{equity}}\frac{E}{V}$$

Method 2

Step 1. Calculate a weighted average of the betas of the equity and debt, using the formula:

$$\beta_{\text{assets}} = \beta_{\text{debt}}\frac{D}{V} + \beta_{\text{equity}}\frac{E}{V}$$

Step 2. Plug β_{assets} into the capital asset pricing formula to give the expected return on the firm's assets.

We showed that the two methods gave identical answers. But that assumed a world without taxes, where r_{assets}, the company cost of capital, is independent of capital structure. What do we do when taxes matter and the cost of capital depends on capital structure?

Method 1 is easily modified by replacing r_{debt} with $r_{debt}(1 - T_c)$. The new step 2 is:

> *Step 2.* Calculate the weighted-average cost of capital, using the after-tax cost of debt:

$$r^* = r_D(1 - T_c)\frac{D}{V} + r_E\frac{E}{V}$$

Method 2 can also be modified for taxes, but there are a number of tricks and traps. To get the right answer, you have to specify T^*, the net tax advantage of corporate borrowing, the firm's financing policy,[13] and the slope of the security market line[14] and then modify the calculations appropriately. Even experts often get confused.

Example. We do not work through the permutations of method 2. We give just one special case where everything works out nicely.

Suppose we follow MM's original analysis and consider only corporate taxes. Moreover, the debt supported by the project is assumed fixed over the life of the project, just as in our initial Geothermal project analysis. Then method 2 is easily modified. First, multiply β_{debt} by 1 minus the corporate tax rate and replace V with $V - T_cD$:

$$\beta_{assets} = (1 - T_c)\,\beta_{debt}\frac{D}{V - T_cD} + \beta_{equity}\frac{E}{V - T_cD}$$

This calculates the beta of the firm *if* it were all-equity-financed.

Plugging β_{assets} into the capital asset pricing model gives the *opportunity* cost of capital, r. Finally, get an *adjusted* cost of capital r^* using the MM formula, with the net tax advantage of debt T^* set equal to the corporate rate T_c:

$$r^* = r(1 - T_cL)$$

So this case works out neatly. Remember, though, that MM's original analysis assigns the maximum possible tax advantage to corporate borrowing. If the true advantage is less and you want an exact answer, then all three steps of the tax-modified method 2 have to be adjusted. Unfortunately the required changes are messy and confusing, and not many financial managers attempt them.

Mistakes People Make in Using the Weighted-Average Formula

The weighted-average formula is very useful but also dangerous. It tempts people to make logical errors. For example, manager Q, who is campaigning for a pet project, might look at the formula

[13] Is the debt supported by the project fixed, or is it adjusted to keep a constant debt-to-market-value ratio as project value fluctuates? Your answer affects the unlevering formula for β_{assets}.

[14] For example, in Merton Miller's "Debt and Taxes" model (Section 18-2), the intercept of the security market line is the *after-tax* risk-free rate, not r_f as in the standard capital asset pricing model. This is explained below at the end of Section 19-4.

$$r^* = r_D(1 - T_c)\frac{D}{V} + r_E\frac{E}{V}$$

and think, "Aha! My firm has a good credit rating. It could borrow, say, 90 percent of the project's cost if it likes. That means $D/V = .9$ and $E/V = .1$. My firm's borrowing rate r_D is 8 percent, and the required return on equity r_E is 15 percent. Therefore

$$r^* = .08(1 - .34)(.9) + .15(.1) = .063$$

or 6.3 percent. When I discount at that rate, my project looks great."

Q is wrong on several counts. First, the weighted-average formula works only for projects that are carbon copies of the firm. The firm isn't 90 percent debt-financed.

Second, the immediate source of funds for a project has no necessary connection with the hurdle rate for the project. What matters is the project's overall contribution to the firm's borrowing power. A dollar invested in Q's pet project will not increase the firm's debt capacity by 90 cents. If it borrows 90 percent of the project's cost, it is really borrowing in part against its *existing* assets. Any advantage from financing the new project with more debt than normal should be attributed to the old projects, not to the new one.

Third, even if the firm were willing and able to lever up to 90 percent debt, its cost of capital would not decline to 6.3 percent (as Q's naive calculation predicts). You cannot increase the debt ratio without creating financial risk for stockholders and thereby increasing r_E, the expected rate of return they demand from the firm's common stock. Going to 90 percent debt would certainly increase the borrowing rate, too.

19-4 DISCOUNTING SAFE, NOMINAL CASH FLOWS

Suppose you're considering purchase of a \$100,000 machine. The manufacturer sweetens the deal by offering to finance the purchase by lending you \$100,000 for 5 years, with annual interest payments of 5 percent. You would have to pay 13 percent to borrow from a bank. Your marginal tax rate is 30 percent ($T_c = .3$).

How much is this loan worth? If you take it, the cash flows are:

Period	0	1	2	3	4	5
Cash flow (in thousands)	\$100	−5	−5	−5	−5	−105
Tax shield		+1.5	+1.5	+1.5	+1.5	+1.5
After-tax cash flow	\$100	−3.5	−3.5	−3.5	−3.5	−103.5

What is the right discount rate?

Here you are discounting *safe, nominal* cash flows—safe because your company must commit to pay if it takes the loan,[15] and nominal because the payments would be fixed regardless of future inflation. Now, the correct discount rate for

[15] In theory, "safe" means literally risk-free, like the cash returns on a Treasury bond. In practice, it means that the risk of not paying or receiving a cash flow is small.

safe, nominal cash flows is your company's *after-tax, unsubsidized* borrowing rate.[16] In this case $r^* = r_D(1 - T_c) = .13(1 - .3) = .091$. Therefore:

$$NPV = +100 - \frac{3.5}{1.091} - \frac{3.5}{(1.091)^2} - \frac{3.5}{(1.091)^3} - \frac{3.5}{(1.091)^4} - \frac{103.5}{(1.091)^5}$$

$$= +21.73, \text{ or } \$21{,}730$$

The manufacturer has effectively cut the machine's purchase price from $100,000 to $100,000 − $21,730 = $78,270. You can now go back and recalculate the machine's NPV using this fire-sale price, or you can use the NPV of the subsidized loan as one element of the machine's adjusted present value.

General
Rule

Clearly, we owe an explanation of why $r^* = r_D(1 - T_c)$ for safe, nominal cash flows. It's no surprise that r^* depends on r_D, the unsubsidized borrowing rate, for that is investors' opportunity cost of capital, the rate they would demand from your company's debt. But why should r_D be converted to an *after-tax* figure?

Let's simplify by taking a *1-year* subsidized loan of $100,000 at 5 percent. The cash flows, in thousands, are:

Period	0	1
Cash flow	$100	−105
Tax shield		+1.5
After-tax cash flow	$100	−103.5

Now ask, "What is the maximum amount X that could be borrowed for 1 year through regular channels if $103,500 is set aside to service the loan?"

"Regular channels" means borrowing at 13 percent pretax and 9.1 percent after-tax. Therefore you will need 109.1 percent of the amount borrowed to pay back principal plus after-tax interest changes. If $1.091X = 103{,}500$, $X = 94{,}867$. Now if you can borrow $100,000 by a subsidized loan, but only $94,867 through normal channels, the difference ($5133) is money in the bank. Therefore, it must also be the NPV of this one-period subsidized loan.

When you discount a safe, nominal cash flow at an after-tax borrowing rate, you are implicitly calculating the *equivalent loan*, the amount you could borrow through normal channels, using the cash flow as debt service. Note that:

$$\text{Equivalent loan} = PV\begin{pmatrix}\text{cash flow}\\ \text{available for}\\ \text{debt service}\end{pmatrix} = \frac{103{,}500}{1.091} = 94{,}867$$

In some cases, it may be easier to think of taking the lender's side of the equivalent loan rather than the borrower's. For example, you could ask, "How much would my company have to invest today in order to cover next year's debt service on the subsidized loan?" The answer is $94,867: if you lend that amount at 13 percent, you will earn 9.1 percent after tax, and therefore have $94{,}867(1.091) = 103{,}500$. By this transaction, you can in effect cancel, or "zero

[16] In Section 13-1, we calculated the NPV of subsidized financing using the *pretax* borrowing rate. Now you can see that was a mistake. Using the pretax rate implicitly defines the loan in terms of its pretax cash flows, violating a rule promulgated way back in Section 6-1: *Always* estimate cash flows on an after-tax basis.

POOR ORIGINAL

out," the future obligation. If you can borrow $100,000 and then set aside only $94,867 to cover all the required debt service, you clearly have $5133 to spend as you please. That amount is the NPV of the subsidized loan.

Therefore, regardless of whether it's easier to think of borrowing or lending, the correct discount rate for safe, nominal cash flows is an after-tax interest rate.[17]

In some ways, this is an obvious result once you think about it. Companies are free to borrow or lend money. If they *lend*, they receive the after-tax interest rate on their investment; if they *borrow* in the capital market, they pay the after-tax interest rate. Thus, the opportunity cost to companies of investing in debt-equivalent cash flows is the after-tax interest rate. This is the adjusted cost of capital for debt-equivalent cash flows.

Some Further Examples

Here are some further examples of debt-equivalent cash flows:

Payout Fixed by Contract. Suppose you sign a maintenance contract with a truck leasing firm, which agrees to keep your leased trucks in good working order for the next 2 years in exchange for 24 fixed monthly payments. These payments are debt-equivalent flows.[18]

Depreciation Tax Shields. Capital projects are normally valued by discounting the total after-tax cash flows they are expected to generate. Depreciation tax shields contribute to project cash flow, but they are not valued separately; they are just folded into project cash flows along with dozens, or hundreds, of other specific inflows and outflows. The project's opportunity cost of capital reflects the average risk of the resulting aggregate.

However, suppose we ask what depreciation tax shields are worth *by themselves*. For a firm that's sure to pay taxes, depreciation tax shields are a safe, nominal flow. Therefore, they should be discounted at the firm's after-tax borrowing rate.[19]

Suppose we buy an asset with a depreciable basis of $200,000, which can be depreciated by the 5-year tax depreciation schedule (see Table 6-5). The resulting tax shields are:

Period	1	2	3	4	5	6
Percentage deductions	20	32	19	11.5	11.5	6
Dollar deductions (in thousands)	$40	64	38	23	23	12
Tax shields at $T_c = .30$	$12	19.2	11.4	6.9	6.9	3.6

The after-tax discount rate is $r_D(1 - T_c) = .13(1 - .3) = .091$. (We continue to assume a 13 percent pretax borrowing rate and a 30 percent marginal tax rate.)

[17] Borrowing and lending rates should not differ by much if the cash flows are truly safe—that is, if the chance of default is small. Usually your decision will not hinge on the rate used. If it does, ask which offsetting transaction—borrowing or lending—seems most natural and reasonable for the problem at hand. Then use the corresponding interest rate.

[18] We assume you are locked into the contract. If it can be canceled without penalty, you may have a valuable option.

[19] The depreciation tax shields are cash inflows, not outflows as for the contractual payout or the subsidized loan. For safe, nominal inflows, the relevant question is, "How much could the firm borrow today if it uses the inflow for debt service?" You could also ask, "How much would the firm have to lend today to generate the same future inflow?"

The present value of these shields is:

$$PV = \frac{[illegible]}{1.091} + \frac{19.2}{(1.091)^2} + \frac{11.4}{(1.091)^3} + \frac{5.9}{(1.091)^4} + \frac{3.2}{(1.091)^5} + \frac{3.5}{(1.091)^6}$$

$$= +47.4, \text{ or } \$47,400$$

Adjusted Discount Rates for Debt-Equivalent Cash Flows

You may have wondered whether our procedure for valuing debt-equivalent cash flows is consistent with the adjusted-discount-rate approaches presented earlier in this chapter. Yes, it is consistent, as we will now illustrate.

Remember from Section 18-2 that the value of corporate interest tax shields depends on the personal tax rates paid by debt and equity investors. No one knows for sure what the relevant personal rates actually are. The polar views are those of Modigliani and Miller (MM), on one hand, and Miller, on the other. MM assume that investors face the same tax rate on debt and equity income, so that only corporate taxes need be considered; in that case, $T^* = T_c$. But Miller argues that debt investors pay higher effective tax rates than equity investors, so much so that any advantage of the corporate interest tax shield is entirely offset, and $T^* = 0$.

Let's look at a very simple numerical example from each viewpoint. Our problem is to value a \$1 million payment to be received from a blue-chip company 1 year hence. After taxes at 34 percent, the cash inflow is \$660,000. The payment is fixed by contract.

Since the contract generates a debt-equivalent flow, the opportunity cost of capital is the rate investors would demand on a 1-year note issued by the blue-chip company, which happens to be 8 percent. For simplicity, we'll assume this is your company's borrowing rate too. Our valuation rule for debt-equivalent flows is therefore to discount at $r^* = r_D(1 - T_c) = .08(1 - .34) = .053$:

$$PV = \frac{660{,}000}{1.053} = \$626{,}800$$

Valuing Debt-Equivalent Cash Flows under MM Assumptions. Now let's see how MM would address this same problem. The opportunity cost of capital is still $r_D = .08$, or 8 percent. With $T^* = T_c$, the MM adjusted-cost-of-capital formula is $r^* = r_D(1 - T_cL)$.

What is L? In Section 19-2, we defined it as a project's "marginal contribution to the firm's debt capacity," expressed as a fraction of project value, which is normally well below 1. But the debt capacity of a safe cash flow is 100 percent of its value, because the firm could "zero out" the cash flow by taking out an equivalent loan with the same after-tax debt service. Thus, we can think of "debt capacity" as the offsetting equivalent loan. Since the equivalent loan has exactly the same present value as the debt-equivalent flow, $L = 1$.

The MM adjusted-cost-of-capital formula for debt-equivalent cash flows therefore boils down to the same after-tax borrowing rate we used to discount the \$660,000 inflow:

$$r^* = r(1 - T_cL) = r_D(1 - T_c) = .08(1 - .34) = .053$$

We get the same result from the Miles-Ezzell formula. With $r = r_D$ and $L = 1$:

$$r^* = r - Lr_DT_c\left(\frac{1 + r}{1 + r_D}\right)$$

$$= r_D - 1 \times r_D T_c \left(\frac{1 + r_D}{1 + r_D}\right)$$

$$= r_D - r_D T_c = r_D(1 - T_c)$$

Let's also try an APV calculation under MM assumptions. This is a two-part calculation. First, the \$660,000 inflow is discounted at the opportunity cost of capital, 8 percent. Second, we add the present value of interest tax shields on debt supported by the project. Since the firm can borrow 100 percent of the cash flow's value, the tax shield is $r_D T_c$APV, and APV is:

$$\text{APV} = \frac{660{,}000}{1.08} + \frac{.08(.34)\text{APV}}{1.08}$$

Solving for APV, we get \$626,900, which save for a rounding error,[20] is the same answer we obtained by discounting at the after-tax borrowing rate.

Thus our valuation rule for debt-equivalent flows is a special case of the APV rule once we adopt MM's assumptions about debt and taxes.

Valuing Debt-Equivalent Cash Flows under Miller's Assumptions. But suppose that you share Miller's view that there is no tax advantage to debt, so that $T^* = 0$. That would seem to imply that debt-equivalent cash flows should be discounted at the *pretax* borrowing rate. For example, if we set $T^* = 0$ in the MM adjusted-cost-of-capital formula, $r^* = r(1 - T^*L) = r(1 - 0 \times L) = r$, the opportunity cost of capital, which we would normally set at $r = r_D$ for debt-equivalent flows.

However, the reason why $T^* = 0$ in Miller's theory is that debt investors' personal tax rate equals the corporate rate ($T_p = T_c$), while the effective tax rate on equity income is zero ($T_{pE} = 0$). (See Section 18-2.) Thus debt investors demand a higher pretax rate of return on safe investments than equity investors do. For example, if the after-personal-tax return on debt is $.08(1 - .34) = .053$, or 5.3 percent, then investors will also be content with a 5.3 percent rate of return on a safe, *untaxed* equity investment.

Therefore, equity investors' opportunity cost of capital for a safe cash flow is the *after-tax* interest rate: $r = r_D(1 - T_p) = r_D(1 - T_c)$.

Thus, although $T^* = 0$ in Miller's world, we nevertheless end up discounting debt-equivalent flows at $r_D(1 - T_c)$, because that is the rate the firm's stockholders demand.

19-5 SUMMARY

Investment decisions always have side effects on financing: Every dollar spent has to be raised somehow. Sometimes the side effects are irrelevant or at least unimportant. In an ideal world with no taxes, transaction costs, or other market imperfections, only investment decisions would affect firm value. In such a world firms could analyze all investment opportunities as if they were all-equity financed. Firms would decide which assets to buy and then worry about getting the money to pay for them. No one would worry about where the money might come from, because debt policy, dividend policy, and all other financing choices would have no impact on stockholders' wealth.

[20] The after-tax borrowing rate is actually $r^* = .0528$. Discounting at the rounded rate (.053) reduces PV to \$626,800 from the correct figure, \$626,900.

The side effects cannot be ignored in practice. Therefore in this chapter we showed you how they should be taken into account.

The technique is simple. We first calculate the present value of the project as if there are no important side effects. Then we adjust present value to calculate the project's total impact on firm value. The rule is to accept the project if adjusted net present value (APV) is positive:

$$\text{Accept project if APV} = \text{base-case NPV} + \begin{array}{c}\text{present value}\\ \text{of financing}\\ \text{side effects}\end{array} > 0$$

The base-case NPV is the project's NPV computed assuming all-equity financing and perfect capital markets. Think of it as the project's value if it were set up as a separate mini-firm. You would compute the mini-firm's value by forecasting its cash flows and discounting at the opportunity cost of capital for the project. The cash flows should be net of the taxes that an all-equity-financed mini-firm would pay.

Financing side effects are evaluated one by one and their present values added to or subtracted from base-case NPV. We looked at several cases:

1. *Issue costs.* If accepting the project forces the firm to issue securities, then the present value of issue costs should be subtracted from base-case NPV.
2. *Interest tax shields.* Debt interest is a tax-deductible expense. Most people believe that interest tax shields contribute to firm value. Thus a project that prompts the firm to borrow more generates additional value. The project's APV is increased by the present value of interest tax shields on debt the project supports.
3. *Special financing.* Sometimes special financing opportunities are tied to project acceptance. For example, the government might offer subsidized financing for socially desirable projects. You simply compute the present value of the financing opportunity and add it to base-case NPV.

Remember not to confuse *contribution to corporate debt capacity* with the immediate source of funds for investment. For example, a firm might, as a matter of convenience, borrow \$1 million for a \$1 million research program. But the research would be unlikely to contribute \$1 million in debt capacity; a large part of the \$1 million new debt would be supported by the firm's other assets.

Also remember that *debt capacity* is not meant to imply an absolute limit on how much the firm *can* borrow. The phrase refers to how much it *chooses* to borrow. Normally the firm's optimal debt level increases as its assets expand; that is why we say that a new project contributes to corporate debt capacity.

Calculating APV may require several steps: one step for base-case NPV, and one for each financing side effect. Many firms try to calculate APV in a single calculation. They do so by the following procedure. After-tax cash flows are forecast in the usual way—that is, as if the project is all-equity-financed. But the discount rate is adjusted to reflect the financing side effects. If the discount rate is adjusted correctly, the result is APV:

$$\begin{array}{c}\text{NPV at adjusted}\\ \text{discount rate}\end{array} = \text{APV} = \begin{array}{c}\text{NPV at opportunity}\\ \text{cost of capital}\end{array} + \begin{array}{c}\text{present value of}\\ \text{financing side effects}\end{array}$$

Unfortunately, there is no formula for adjusting the discount rate that is simple and generally correct. However, there are two useful rules of thumb. The first is the Modigliani-Miller (MM) formula:

$$r^* = r(1 - T^*L)$$

Here r is the opportunity cost of capital and r^* is adjusted cost of capital. The quantity T^* is the net tax saving per dollar of interest paid, and L is the proportional contribution made by the project to corporate borrowing power. MM's formula is strictly correct only for projects offering level, perpetual cash-flow streams and supporting permanent debt. But the errors from applying it to other types of projects are not serious.

Miles and Ezzell have developed another formula,

$$r^* = r - Lr_D T^* \left(\frac{1 + r}{1 + r_D}\right)$$

This formula assumes the firm will adjust its borrowing to follow every fluctuation in future project value. If this assumption is right, the formula works for projects of any maturity or cash-flow pattern.

The Miles-Ezzell formula typically gives adjusted discount rates slightly higher than MM's. The truth is probably somewhere in between. However, both formulas assume that the present value of additional interest tax shields is the *only* side effect of accepting the project.

To apply the MM and Miles-Ezzell formulas, you need to know r, the cost of capital for an all-equity-financed project. If you don't know r, you may be able to calculate the adjusted cost of capital using the weighted-average or textbook formula:

$$r^* = r_D(1 - T_c)\frac{D}{V} + r_E \frac{E}{V}$$

Here r_D and r_E are the expected rates of return demanded by investors in the firm's bonds and stock, respectively. The quantities D and E are the current *market values* of debt and equity, and V is the total market value of the firm ($V = D + E$).

Strictly speaking, this formula only works for projects that are carbon copies of the existing firm—projects with the same business risk that will be financed to maintain the firm's current, market debt ratio. But firms can use it as a benchmark rate, to be adjusted upward for especially risky projects and downward for especially safe ones.

Finally, we offered a simple valuation rule for safe, nominal cash flows: Simply discount at the after-tax interest rate.

Remember that each of these formulas rests on special assumptions. When you encounter a project that seriously violates these assumptions, you should go back to APV.

QUIZ

FURTHER READING

The adjusted-present-value rule was developed in:

S. C. Myers: "Interactions of Corporate Financing and Investment Decisions—Implications for Capital Budgeting," *Journal of Finance*, 29: 1–25 (March 1974).

Formulas for the adjusted discount rate are explained in:

F. Modigliani and M. H. Miller: "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433–443 (June 1963).

M. H. Miller and F. Modigliani: "Some Estimates of the Cost of Capital to the Electric Utility Industry: 1954–1957," *American Economic Review*, 56: 333–391 (June 1966).

J. Miles and R. Ezzell: "The Weighted Average Cost of Capital, Perfect Capital Markets and Project Life: A Clarification," *Journal of Financial and Quantitative Analysis*, 15: 719–730 (September 1980).

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

Docket No. R-00973954

Q.77. Does Dr. Jones' analysis consider whether any units that do not recover their going-forward costs from revenues earned in the energy and capacity markets will be shut down? If so, please explain how. If not, please explain why not.

A.77. No. Dr. Jones' analysis did not assess the going-forward economics of individual generating units. Generating unit shut downs were based on those retirement dates specifically identified by the various PJM companies.

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.27. On 11 April 1997, the New York Times reported that General Public Utilities announced that it was considering sale or closure of the Oyster Creek nuclear plant by the year 2000. Please describe how you included the probability of plant closure of Oyster Creek and other high cost facilities.

A.27. Plant closures specifically identified by PJM companies would be modeled in PP&L's analysis. In the case of the Oyster Creek nuclear plant, this information was made public eleven days after PP&L's restructuring filing. PP&L had no advance information regarding the potential closure or sale of this plant prior to that notice. Attempting to model other plant closures not identified by PJM companies and when those closures might occur would be speculative.

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.

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.18. Regarding your testimony at page 28, lines 14 to 15:

a. Is it your testimony that the EGEAS model forecasts planned outages to occur randomly? Please explain your response.

b. Please provide all your reasons for assuming that unplanned outages occur randomly. Are unplanned outages completely unrelated to extreme weather conditions?

A.18.

a. No. The EGEAS model does not model/forecast planned outages on a random basis. Within the model, annual forecast peak load and energy is fit into an annual system load shape which is subdivided into months and weeks. Planned maintenance for each generating unit is defined by identifying the precise week that maintenance begins, and the duration of the required maintenance.

b. The EGEAS model represents unplanned outages using a probabilistic method. Generating unit forced outage rates are input into the model based on historical unit performance. The historical performance of each generating unit captures various events related to unplanned outages, including extreme weather conditions, if any. The EGEAS model dispatches generating units based on fuel plus variable O&M costs to meet system load needs in any hour, and each unit's output is limited by its availability (in accordance with the forced outage rate) to meet system needs.

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.33. *For each non-utility generating plant included in the EGEAS PJM forecast, please provide your assumptions for fuel cost per kWh, variable O&M cost per kWh, incremental 'going forward' costs, capacity, and generation for each year of the forecast period.*

A.33. PJM non-utility generators (NUGs) are modeled in EGEAS as an aggregated, base load energy purchase contract. The NUGs are considered to be "must run" units whose energy must be accepted by the PJM company with which they are under contract pursuant to PURPA Section 210 (or some alternative contractual arrangement). The NUGs are not dispatched based on system pool economics. They provide energy to the pool whenever the units are available to run. As such, the PJM NUGs are modeled in EGEAS as firm energy contracts with no costs. The forecast NUG generation for PJM is as follows:

Year	PJM NUG GWH	Year	PJM NUG GWH
1997	24,970	2007	30,410
1998	26,974	2008	29,584
1999	29,373	2009	29,079
2000	30,993	2010	27,928
2001	30,985	2011	27,871
2002	31,041	2012	27,871
2003	30,792	2013	27,871
2004	30,492	2014	27,870
2005	30,410	2015	27,844
2006	30,410	2016	27,844

S. T. Jones
D. A. Krall

Pennsylvania Power & Light Company
Response to Interrogatories of the
PP&L Industrial Customer Alliance, Set VII
Dated June 5, 1997

Docket No. R-00973954

Q.1. Refer to PP&L's answer to OCA-III-74. Please provide workpapers showing the following information:

a. Derivation of the 8.91% cost of capital

b. Workpapers showing the connection between the annual capacity cost figures shown on STJ-8 and the figures shown on the response to OCA-III-74.

c. To the extent that the capacity figures reported on STJ-8 rely on fixed charge rate or annual carrying cost rate of any kind (whether levelized real, levelized nominal, or otherwise), please provide all workpapers supporting the figures uses.

A.1. a. See the response to Question 12 of Interrogatories of the PP&L Industrial Customer Alliance, Set VIII, Dated June 5, 1997.

b. There are no workpapers. The response to Question 74 of Interrogatories of the Office of Consumer Advocate, Set III, Dated April 17, 1997, lists the assumptions the EGEAS model uses to assess the incremental cost of adding new capacity to meet system requirements. The market clearing capacity prices shown in Exhibit STJ 8 are related to these EGEAS inputs in that the prices shown in Exhibit STJ 8 are sufficient such that the expected revenue stream from capacity, plus revenues from energy sales (if any) generated from installation to the end of the unit's life, would cover the costs of installing new capacity.

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

Pennsylvania Power & Light Company
Response to Interrogatories of the
PP&L Industrial Customer Alliance, Set VII
Dated June 5, 1997

Docket No. R-00973954

Q.4. Based on Dr. Jones' experience in the gas and oil industries, would he consider a return on investment of 8.91% comparable with the returns usually sought by oil and gas producers in development of new projects?

A.4. An 8.91% return is comparable or even greater than realized returns experienced by oil and gas companies, particularly for investments in facilities.

Pennsylvania Power & Light Company
Response to Interrogatories of the
PP&L Industrial Customer Alliance, Set VII
Dated June 5, 1997

Docket No. R-00973954

Q.5. Does Dr. Jones believe that developers of competitive generation resources would be a more or less risky venture than investments he is familiar with in the oil and gas industries?

A.5. Without a specific facilities investment risk profile for a hypothetical oil and gas industry capital project, Dr. Jones can only respond in general terms. However, given that new generation equipment will both embody the latest competitive technology and be guaranteed some payment for making capacity available to PJM, the risk to investors would appear to be less than some oil and gas facilities projects.

Pennsylvania Power & Light Company
Response to Interrogatories of the
PP&L Industrial Customer Alliance, Set VII
Dated June 5, 1997

Docket No. R-00973954

Q.6. Indicate specifically Dr. Jones' qualifications and expertise in development of macroeconomics forecasts, such as his forecast of 2.5% inflation that he used to develop market energy prices.

A.6. Dr. Jones has a long history in forecasting financial and energy market variables. His experience is listed in Exhibit STJ 1.

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.4. Regarding your testimony at page 17 lines 1 to 11:

a. Is it your testimony that the specified approach is the only acceptable approach for determining the magnitude of stranded costs? Please explain your response, and outline any other methods that you believe are appropriate.

b. Do you agree that a net present value analysis of the type you suggest involves a large number of assumptions (discount rate, market price forecasts, cost forecasts, operating rates, potential for refurbishing/repowering, environmental law changes, operating costs, salvage value, etc.) upon which reasonable and knowledgeable industry analysis may disagree? Please explain any negative response.

A.4.

a. Any stranded cost estimation approach requires a comparison of a utility's known and measurable net generation-related costs that traditionally would be recoverable under a regulated environment and the revenues a utility would receive in a competitive market. Because the Electricity Generation Customer Choice and Competition Act requires estimating stranded costs at this point in time, a forecast of market prices is necessary. Any other proposed stranded cost estimation technique may differ in details, but fundamentally it would be similar to the approach Professor Kalt outlined in his testimony.

b. The type of analysis that Professor Kalt described in his testimony does require assumptions with which some reasonable and knowledgeable analysts may disagree.

J. M. Kleha

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.11. Regarding your proposal for the CTC true-up mechanism:

a. Please provide a numerical example of how the true-up mechanism will work.

b. Will variances by rate class be tracked and considered as part of the true-up mechanism? Will CTC's for various rate classes expire at different times? Please explain your response.

A.11. a. See Attachment 1 for an illustrative example.

b. Under PP&L's proposed CTC reconciliation procedure, over/undercollection balances by rate class will not be maintained. The CTC's applicable to individual rate classes will not expire at different times during the transition period. See the response to Question OTS-RB-43 of Interrogatories of the Office of Trial Staff Dated May 20, 1997 for additional information.

PENNSYLVANIA POWER & LIGHT COMPANY

ILLUSTRATIVE EXAMPLE OF CTC REVENUE OVER/UNDER COLLECTIONS

($1000)

LINE NO.	YEARS	CTC REVENUE COLLECTED	CTC REVENUE BASE	ANNUAL OVER/(UNDER) COLLECTION	CUMULATIVE BALANCE
1.	1999	930,731	930,731	0	0
2.	2000	838,991	822,540	16,451	16,451
3.	2001	667,903	681,534	(13,631)	2,820
4.	2002	579,927	591,762	(11,835)	(9,015)
5.	2003	565,965	554,868	11,097	2,082
6.	2004	507,949	518,315	(10,366)	(8,284)
7.	2005	568,400	568,400	0	(8,284)
8.	2006	8,284	0	8,284	0

NOTE: OVERCOLLECTIONS ARE BASED ON A 2% INCREASE IN SALES VOLUME (KWH) WHEN COMPARED TO THE BASE PERIOD (1996) SALES VOLUME (KWH)
UNDERCOLLECTIONS ARE BASED ON A 2% DECLINE IN SALES VOLUME (KWH) WHEN COMPARED TO THE BASE PERIOD (1996) SALES VOLUME (KWH)

Pennsylvania Power & Light Company
Response to Interrogatories
of Office of Small Business Advocate
Dated May 22, 1997

Docket No. R-00973954

Q.41. Please provide a comprehensive list of your reasons why residential customers are offered the option of participating in the Customized Rate Design Option (CRDO) while small business customers (GS-1 and GS-3) are denied that option.

A.41. PP&L believes that the Customized Rate Design Option provides several important benefits. It moves toward marginal cost pricing which sends more efficient price signals to customers and is more consistent with a competitive market. It offers customers a significant rate reduction for incremental usage, which should spur development of a competitive market, provide for significant rate reductions for customers and promote economic development. Based upon prior experience, expertise, and general economic principles, PP&L believes that these benefits can be achieved in all customer segments. However, PP&L has proposed that residential customers be able to choose between the Customized Design and a Traditional Design out of concern for customer education; specifically, that some residential customers may only be comfortable with a rate structure that doesn't change at all. PP&L has proposed that all commercial and industrial customers take service under the Customized Design in the interest of maximizing the economic development potential of the Customer Choice Act.

D. G. Lennon

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set VI
<u>Dated Thursday, May 15, 1997</u>
Docket No. R-0097394

Q.17. What research or information does the Company have that indicates that customers want a Handbook to learn about customer choice and retail electric competition?

A.17. The Company's customer satisfaction research that is conducted on an ongoing basis indicates that customers want the utility to be able to answer their questions. Interactions with customers on a day-to-day basis by employees with customer contact confirm that customers, especially residential and small commercial customers, do not fully understand customer choice. The law also recognizes that there are issues, such as consumer protection from fraud, that need to be communicated to customers. The focus group research for the New Hampshire and Massachusetts pilots indicated that customers wanted "standardized information...so they could compare." The development of a Handbook appears to address these needs. Customer reaction to the Customer Choice Pilot Handbook, as measured by quantitative and qualitative research by an outside consultant, will confirm whether or not the Handbook meets customer needs.

EXHIBIT RDK-4

RECENT PRESS REPORTS

2 July 1997

Aging New Jersey Nuclear Plant May Be Closed or Sold

By ROBERT HANLEY

HACKENSACK, N.J., April 10 — Owners of the Oyster Creek nuclear power plant, one of the nation's oldest, said today that they were exploring options to sell or close it by 2000.

Fred D. Hafer, president of General Public Utilities, said the plant, in central New Jersey, was one of the least cost-efficient of the nation's nuclear plants and would be too expensive to operate once free-market competition begins for electrical customers in New Jersey in the late 1990's.

The announcement comes four months after the owners of the Connecticut Yankee plant decided to close it. Power industry experts have noted that changing economics and abundant power from non-nuclear sources have put older, smaller nuclear plants like Oyster Creek and Connecticut Yankee in peril.

Mr. Hafer said the company was publicly discussing its plans now, before making a final decision, to show the investment community that the company was taking aggressive and decisive steps before electricity prices are decontrolled.

The response was quick: GPU's stock [illegible] 50 cents today in heavy trading on the New York Stock Exchange, closing at $31.75.

Mr. Hafer said deregulation was the "driving force" behind the planning, which he said should not be interpreted as a negative view of the future of the nuclear power industry.

Currently, company officials said, it costs 3.7 cents to generate each kilowatt hour of electricity at Oyster Creek, while a kilowatt hour fetches only 2.2 cents from retail customers.

The New York Times

The Oyster Creek plant is becoming too expensive to operate.

Costs for nuclear fuel and operations, including the plant's $45 million annual payroll, account for 3.2 of the 3.7 cents, a company spokesman, John Fidler, said. He said only about eight of the nation's other 100 nuclear power plants have higher operational and fuel costs.

Mr. Hafer said the company, which has not ruled out continuing to operate Oyster Creek until its license expires in 2009, planned to make a decision by late summer or early fall. That is about the time the company must file a reorganization plan that is required by the Board of Public Utilities, the New Jersey regulatory agency overseeing the decontrol of electricity rates in the state.

Under current plans, deregulation is to start in October 1998, with 5 percent of the state's 3.3 million electricity customers to be allowed to shop for the cheapest rates. More customers are to be phased in over six-month intervals, until all are free to choose suppliers by April 2001.

Gov. Christine Todd Whitman, a firm advocate of deregulation, has said she wants a 5 to 10 percent reduction in electricity rates under a free market. But Mr. Hafer and other company officials said today that despite cost-saving measures in recent years, Oyster Creek remained too uneconomical to provide much of a reduction for the 200,000 customers it serves in central New Jersey.

Power generated by the plant has also been used in Pennsylvania and Maryland.

The plant was opened in 1969. At the time, it was the nation's third nuclear generating plant. Construction cost $90 million.

The company's asking price, if it opts to sell, will be $700 million, Mr. Hafer said. That figure, he said, represents GPU's net investment over the plant's 28-year life.

Much of the money was spent, Mr. Hafer said, for improved storage of radioactive wastes and for new equipment to enhance safety after the accident at the Three Mile Island nuclear power plant 18 years ago. GPU also owns Three Mile Island.

Mr. Hafer refused to speculate on the prospects of finding a buyer if a decision to sell is made. "We'll give it our best shot," he said.

But some industry experts said finding a buyer was unlikely. Dan Scotto, an analyst for Bear Stearns, said: "Who is going to buy a nuclear plant that is 30 years old?"

GPU officials say Oyster Creek has two major drawbacks. It is small, with about 620 megawatts of generating capacity, and has no room to add a second reactor.

Other plants around the country have double Oyster Creek's capacity and are still able to satisfy staffing requirements of the Federal Nuclear Regulatory Commission with the same size labor force — 900 workers — as Oyster Creek.

New Jersey's Board of Public Utilities must approve any plan for sale or closure. Philip Leary, a spokesman for the board, said a review would focus on two points — how GPU planned to replace Oyster Creek's electricity and what the impact would be on jobs, customers' rates and the environment.

Company officials said today they had no plans to build any new generating plants in central New Jersey. But they said there was a possibility that other companies would build electrical plants powered by gas-fired turbines. Such plants have become common around the nation. If such a plant one day replaced Oyster Creek, GPU could buy and distribute its electricity, Mr. Fidler said.

Mr. Scotto, of Bear Stearns, said that although closing the plant would cost about $400 million, much of the money has already been put away.

The announcement prompted some immediate criticism. In the New Jersey Assembly, John S. Wisniewski, Democrat of Middlesex County, called for a bar on sale or closure.

"GPU is ceasing to be a generating utility in new Jersey," he said. "It has abandoned its New Jersey employees. It has abandoned numerous communities. The utility has essentially become a broker of electricity, a power reseller."

New York Times 11 April 1997

RDK-2-1

Wall Street Journal 18 June 1997

Nuclear Plants Face Huge Costs to Fix

By Ross Kerber
Staff Reporter of The Wall Street Journal

Pressure sensors at the Zion nuclear-power plant near Chicago won't survive hot accidents. Until a recent fix, emergency-coolant monitors were significantly inaccurate at the Diablo Canyon plant in California. Vermont Yankee is studying a permanent solution for a ventilation system that wouldn't supply enough air for control-room operators in a crisis. Supposedly fail-safe emergency cooling pumps are flawed at the Salem nuclear facility in New Jersey.

INDUSTRY FOCUS

These disclosures are part of an unusual confessional exercise in which utilities have told the U.S. Nuclear Regulatory Commission of hundreds of cases in which they have failed to meet the technical terms of their licenses to operate. The NRC began soliciting admissions of problems from the nation's 109 nuclear-power plants last October partly in response to whistle-blowers' complaints about its own lax oversight at several facilities.

The plants were promised freedom from most sanctions, but the exercise is nonetheless proving costly for some: Agency officials say the volunteered information raises overall safety concerns for many nuclear plants — and analysts and power-company executives expect some older plants may have to spend as much as $100 million each to get up to snuff.

Coupled with state moves to deregulate power markets, this additional spending may be enough to prompt the early shutdown of two dozen nuclear plants over the next five years, says Bear Stearns analyst Dan Scotto. (An early shutdown is one occurring before a plant's operating license expires.) More conservative, NRC commissioner Nils Diaz estimates only one dozen early shutdowns. He won't name plants — but the cleanup bill for decommissioning that many facilities would be in the vicinity of $7 billion.

"There's never been a bloodletting like this," says Stephen Maloney, a utilities consultant in Boston. Centerior Energy Corp.'s president for power generation,

Change of Plans

PLANT	LICENSE EXPIRATION	STATUS
Connecticut Yankee	2007	Closed permanently in December, 1996 by owners led by Northeast Utilities.
Zion units 1 and 2 (Illinois)	2013	Off-line pending safety reviews. Owner Unicom Corp. says neither plant is worth upgrading and both likely will close permanently around 2005.
Maine Yankee	2008	Off-line pending safety reviews. Owners led by Central Maine Power say sale or closure likely.
Oyster Creek (N.J.)	2009	On-line. Owner GPU Inc. mulling sale or closure.

MANAGEMENT

Wall Street Journal 18 June 1997

Problems

Gary Leidich, says: "A lot of utilities are looking really seriously at shutting down if they have a big regulatory problem."

Three early closures have already been announced since December—the two reactors at the Zion plant, owned by **Unicom Corp.**, and the Connecticut Yankee reactor, primarily owned by **Northeast Utilities**. Also, the largest owner of the Maine Yankee plant, **Central Maine Power Co.**, has said that an early shutdown is likely if a buyer can't be found. A factor in all these cases is the projected cost of fixing technical problems.

Most observers think vulnerable reactors are those with fuel and labor costs above two cents per kilowatt-hour. That would include plants like **Illinova Corp.**'s Clinton, Ill., reactor; Centerior's Perry, Ohio, plant; and GPU Inc.'s Oyster Creek facility in New Jersey, all of which ran with variable costs around 2.5 cents or more according to a Utility Data Institute analysis of 1995 filings, the most recent available. Oyster Creek is slated for closure or sale; Illinova and Centerior say they have since made improvements.

Unicom and the other utilities say their decisions stem from economics, not safety

Please Turn to Page B4, Column 5

Some Nuclear Plants Face Huge Expenses To Remedy Problems

Continued From Page B1

concerns. But in the nuclear industry, the two are inextricably linked. When regulators demand more safety precautions and oversight, operating costs rise – often to levels that aren't competitive with other forms of power production.

Maine Yankee's owners have shelled out $13 million a month for replacement power since December, when the plant was taken off-line so engineers could fireproof control wires as described by licensing documents. Zion told regulators in April that some stress monitors on steam tubes would likely fail in the accidents they were supposed to help detect, while other devices were never tested to see if they could withstand high temperatures. Both conditions could make it difficult to prevent a radioactive leak, and the latter problem "has existed since original installation in 1973," the plant's report states.

Tom Maiman, Unicom's chief nuclear officer, says the devices will be tested and replaced if necessary before Zion runs again. He says the issues weren't spotted before because "we've never had the question raised before."

In other cases, Diablo Canyon managers say that they have since recalibrated the faulty measuring instruments and that public safety wasn't endangered because operators had other ways to measure coolant levels. At the Vermont Yankee nuclear plant, operators have since set aside more portable ventilation fans to keep air in the control room breathable in accidents.

Collectively, such problems weaken the plants' multiple defenses against accidents, says NRC Chairman Shirley Jackson. "When we didn't look as hard or as directly for these issues, the industry didn't look either," she says.

Supporting that, the U.S. General Accounting Office yesterday released an audit criticizing the NRC for lax enforcement of its own rules at the Millstone facility in Waterford, Conn.; Nebraska's Cooper plant; and Salem. To improve its effectiveness, the auditors wrote, the agency must start "holding the licensees accountable for fixing their plants' problems more promptly and addressing management issues more directly." The reviewers did praise some recent changes, such as the NRC's insistence that plants meet the terms of their licensing documents.

Privately, company managers say that effort and others begun by Dr. Jackson aren't justified by the incremental safety benefits they bring. Executives cheered when the NRC's Mr. Diaz, who is considered more lenient than Dr. Jackson, said at a recent regulatory conference that few of the findings raise pressing safety issues.

But even Mr. Diaz says companies weren't living up to a promise made about six years ago to make sure they had in place all the safeguards their planning documents describe. He notes a recent spot-check of the remaining Three Mile Island reactor in Pennsylvania that questioned whether pumps could switch between two supplies of coolant quickly enough to prevent the reactor's fuel core from heating up dangerously during some accident scenarios.

Despite the amnesty, the agency may fine owner GPU because the problems weren't found by the company. Government inspectors found a similar issue at the Salem plant in New Jersey, which owner Public Service Electric & Gas Co. pledges to fix before restarting the reactor this summer.

Ralph Beedle, senior vice president of the industry-funded Nuclear Energy Institute, acknowledges the findings but says utilities never made the promise described by Mr. Diaz, who didn't become a commission member until last year. Rather, says Mr. Beedle, the NRC cut back on its own inspections around 1991 because of budget tightening.

"When you have a vast array of regulations, some things don't get done the way the managers say they should," says Mr. Beedle, who adds that the industry has made safety progress during the same period by reducing radiation exposure to workers. "Are those things that don't get done putting the plants at risk? I'd argue no, but in the meantime you take the heat."

Early closures will force the question of whether electric-company ratepayers or utility shareholders should pay for billions of dollars of cleanup expenses, which were supposed to be collected over the plants' expected life spans. Few plants have yet collected even half of their total decommissioning costs, averaging $582 million apiece. Unicom estimates it will cost $600 million to dispose of the Zion plant after it closes, of which only $250 million has been collected. The utility says it may seek rate increases to meet the costs.

OSBA STATEMENT NO. 1R

8/19/97
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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Pennsylvania	:	
Power & Light Company For	:	
Approval Of Its Restructuring	:	
Plan Under Section 2806 Of	:	Docket No. R-00973954
The Public Utility Code	:	

Rebuttal Testimony and Exhibit of

ROBERT D. KNECHT

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

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REBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Please state your name and describe your previous involvement in these proceedings.

A. My name is Robert D. Knecht. I filed direct testimony in these proceedings on 2 July 1997 on behalf of the Pennsylvania Office of the Small Business Advocate.

Q. Please summarize your rebuttal testimony.

A. I address two issues. First, I revisit the question of how to modify CTC charges in the event that the Commission determines that stranded costs are less than PP&L's proposed "residual CTC" revenues. I am addressing this issue in light of the large reductions in stranded costs presented by experts representing OCA and PPLICA, and in view of the various experts' proposals for allocating and recovering these costs. From this review, I conclude that, if the Commission determines that stranded costs are substantively less than PP&L proposed CTC revenues, class-specific CTC revenue requirements should be determined by amortizing stranded costs over the transition period and allocating those costs to the various classes using a broad-based generation cost allocator. Second, I rebut the recommendations of several witnesses that PP&L's cost allocation methodology approved by the Commission in R-943271 be changed with respect to allocation of universal service costs. The existing, Commission-approved allocation method, as proposed by PP&L in these proceedings, should be continued.

Stranded Cost Assignment and Recovery

Q. Can you contrast the CTC determination methods proposed by PP&L in the extant proceedings and the methodology proposed by PECO in its restructuring filing?

A. PP&L has proposed that class-specific CTC charges be developed by taking existing rates, backing out allocated transmission and distribution costs and further backing out market prices for power, resulting in a "residual CTC" assignment of stranded costs. Under PP&L's calculations, the revenues from the residual CTC charges are insufficient to recover all stranded costs. It is my understanding that PECO has proposed a different method, in which utility generation service rates are calculated as the residual. PECO's method begins with existing rates and subtracts transmission/distribution costs and allocated stranded costs to produce the utility generation service rates. PECO's method apparently has received criticism because the residual generation rates were below market prices, providing utility generation service with a significant competitive advantage.

Q. Is one approach superior to the other?

A. Neither is superior in all cases. If, as in the case of both the PP&L and PECO proposals, residual CTC revenues are less than stranded costs, the PP&L method is preferable, since it does not provide utility generation with a competitive advantage that would impede the development of a competitive market.[1] However, under the residual CTC method, it is possible that CTC revenues could exceed (in present value terms) the calculated stranded costs. In that event, to avoid over-recovery, the effective allocation of CTC charges to

[1] Of course, for the PP&L method to be competitively neutral, it is necessary that the market price forecast used to set utility generation rates be based on the expectations of potential market entrants.

the various classes that falls out of the residual CTC approach must be modified in some way. The generic options for doing so are (a) shortening the period of CTC recovery, (b) amortizing stranded costs over the recovery period and allocating them amongst the classes, and (c) scaling back the residual CTC proposal. The balance of this section of my testimony addresses the issue of the appropriate method to use for making such a modification.

Q. **Please summarize the alternative methods for assigning stranded costs to individual rate classes that have been proffered by PPLICA and OCA in these proceedings.**

A. Mr. Baron, representing PPLICA, advocates a residual CTC approach. Under PPLICA's calculation of stranded costs, however, residual CTC revenues are sufficient to recover stranded costs within the first year of the transition period. Mr. Baron therefore proposes to impose the residual CTC only until stranded costs are recovered.[2] Alternatively, OCA expert Ms. Lee Smith proposes that stranded costs be amortized on a levelized basis over the transition period, and allocated to each class on the basis of the 12 CP production plant allocator.[3]

Q. **What are the implications of the different methods of allocating stranded costs?**

A. The PP&L, PPLICA and OCA methods are summarized in the table below, and compared

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[2] Direct Testimony and Exhibits of Stephen J. Baron on Behalf of the PP&L Industrial Customer Alliance, July 1997, page 11 lines 5-13 and Exhibit _____ (SJB-5).

[3] Direct Testimony of Lee Smith on Behalf of Office of Consumer Advocate, July 1997, page 10 line 4 to page 12 line 2, page 14 lines 15 to 17 and Exhibit LS-5, page 1. Note that the allocator shown in Exhibit LS-5, page 1 of 38.39 percent for the RS class matches the generation level demands allocator (D10) for RS service shown on page 118 of Exhibit JMK-1 (2,044,279/5,325,423). I assume that Ms. Lee advocates applying the same allocator to the other rate classes for allocating stranded costs.

to a straight energy allocator. Details and workpapers are provided in Exhibit RDK-R1. The PP&L and PPLICA methods differ primarily because PP&L recovers CTC revenues over 7 years while PPLICA is calculating its residual over one year.

EFFECTIVE CTC ALLOCATORS				
	PP&L	PPLICA	OCA	kWh
Residential	35.2%	33.4%	40.2%	36.8%
General Service	34.3%	31.7%	28.0%	26.9%
Large Power	23.9%	29.2%	21.1%	23.9%
Interruptible	4.4%	3.6%	8.0%	10.4%
Other	2.2%	2.1%	2.6%	2.1%
Total	100.0%	100.0%	100.0%	100.0%

Q. **Does a strong economic rationale exist for how to allocate stranded costs amongst the classes?**

A. Unfortunately not. Recovery of stranded costs is, of itself, economically inefficient, and is justifiable only on fairness and possibly legal grounds. Thus, in terms of providing efficient (marginal cost) price signals, there is no theoretically correct method for allocating these costs. In effect, these costs are more like a tax than a cost signal. Moreover, even using embedded cost of service principles, the stranded costs computed by PP&L and the intervenors consist of a hodgepodge of cost and revenue items that are not easily identifiable as peak demand related, energy related, or any other obvious allocator. While stranded costs related to utility generation plant (as calculated by PP&L) represent the great majority of stranded costs, it is not correct to simply assume that these costs are demand-related. The stranded cost calculation (using either PP&L's method or alternative methods proposed by other intervenors) consists of measuring the difference between what the utility would have earned under regulation and what it is expected to earn under competition. That calculation includes all of the fixed and variable costs that would be recoverable under regulation, as well as the energy-related and demand-related[4] components of forecast market revenues. Attempting to segregate that calculation into demand and energy components for the purpose of cost allocation would be extremely difficult and controversial at best. Moreover, stranded costs include costs associated with above-market NUG contracts and regulatory assets, complicating any potential classification/allocation scheme. Probably the most that can be safely said is that these costs are related to generation, rather than transmission, distribution or customer service.

Q. How then should stranded costs be allocated, if there is significant room under the rate cap?

A. Since cost causation is problematic, I conclude that the primary criteria should be (a) fairness, (b) minimizing the economic distortions caused by stranded cost recovery, and (c) simplicity.

Q. How does the fairness criterion affect the choice of allocator?

A. Using the fairness criterion, I recommend that the residual CTC approach proposed by Mr. Baron be rejected. Under the residual CTC method, classes are therefore effectively

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[4] The market revenue forecast includes both an energy-related charge and a demand-related charge. However, the problem is more complex than that, since the energy charge is time-of-use based, and therefore contains an implicit demand component. PP&L's existing cost allocation method for energy costs does not differentiate by time-of-use.

allocated stranded costs based on how much room exists under the rate cap. Classes such as GS-1 and GS-3 which have historically over-recovered costs are therefore assigned a greater share of stranded costs.[5] Thus, Mr. Baron's approach serves to extend and exacerbate a historical inequity.

Q. What are the implications of the criterion for minimizing economic distortions?

A. There are two implications: amortization of costs over the transition period and allocation of stranded costs amongst the rate classes. First, as noted in my direct testimony, I recommend that the allowed stranded costs be amortized over the entire transition period, rather than front-loading costs into only the early years.[6] Second, the criterion for minimizing economic distortions suggests that a broad-based allocator is appropriate, so that all customers share in paying the "tax."

Q. Specifically, how should stranded costs be amortized over the transition period?

A. Stranded costs are computed on an NPV basis. PP&L proposes to use a weighted average cost of capital discount rate, and my direct testimony recommends use of the cost of equity as a discount rate. Whichever discount rate is adopted by the Commission should be used to amortize the present value of stranded costs over the transition period on a levelized basis. Computationally, the amortization is equivalent to determining the payment for a fixed rate mortgage, such that the present value of the annual CTC revenues equals the allowed stranded costs.

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[5] Direct Testimony and Exhibits of Robert D. Knecht on Behalf of the Office of Small Business Advocate, 2 July 1997. See pages 40-41 and Exhibit RDK-2, Schedule 7 which shows that average per kWh CTC revenues are much higher for the GS classes under the PP&L residual CTC method.

[6] Ibid., page 12 lines 12 to 15.

Q. But won't a levelized CTC payment scheme cause bundled rates to rise through the transition period as market prices rise?

A. Yes, but that result can be seen as an advantage. Since bundled rates will move with market rates, consumers will face more efficient price signals.

Q. Once stranded costs are amortized over the transition period, what allocator do you propose to use to assign the costs to the various classes?

A. In light of these considerations, I recommend that a broad-based, unbiased total generation cost allocator be developed. I suggest that PP&L produce a revised cost of service study for generation service (both energy and non-energy costs) using a levelized rate of return methodology, such that classes which have historically over-recovered costs are not penalized in the allocation process.[7] The allocator for stranded costs would then be each class' share of total allocated generation costs.

Q. Since generation costs are allocated either on a 12 CP or an energy basis, why are you not proposing a weighted average of these allocators?

A. My interpretation of the Commission's Order in R-943271 is that interruptible service should not be allocated generation plant costs via a simple allocator.[8] Thus, any effort to produce a weighted average allocator would overstate costs assigned to interruptible customers relative to the approved cost allocation method. That Order appears to generally approve the PPLICA proposal, which allocated generation plant costs to

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[7] Of course, classes which historically over-recovered costs will continue to do so for transmission and distribution service.

[8] Pennsylvania Public Utility Commission, Opinion and Order, 27 September 1995, page 196-197.

interruptible customers based on the 12 CP allocator, but provided a cost allocation credit equal to the tariff credit. Neither of the simple allocators reflect this credit. (Note that this logic also argues against the unadjusted production plant allocator proposed by Ms. Smith.) Therefore, for historical consistency and fairness reasons, I recommend that PP&L produce a levelized rate of return cost allocation study that allocates costs to interruptible customers using the methods approved by the Commission in R-943271.[9]

Q. **Mr. Knecht, in your direct testimony, you recommended a scaleback of the PP&L proposed CTC charges in the event that room exists under the cap. Why are you proposing an alternate solution now?**

A. When I filed my direct testimony, I had not considered the possibility that the approved stranded costs might be significantly less than residual CTC revenues. My scaleback proposal was therefore designed for simplicity, since any allocation of stranded costs near the residual CTC revenue level could easily cause rate cap problems. Thus, a scaleback proposal still makes sense if estimated stranded costs are at or near residual CTC revenues. However, if estimated stranded costs fall substantively below residual CTC revenues (say more than 10 or 20 percent below residual revenues), fairness should override simplicity as the key criterion.

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[9] Note that Exhibits JMK-1 and JMK-2 filed in these proceedings do not incorporate any credit to interruptible customers -- neither the PP&L nor the PPLICA proposals from R-943271. (See, for example, Exhibit JMK-1 at page 55-57 lines 53 and 54, wherein adjusted electric plant equals total electric plant.) For the purpose of allocating stranded costs, the Commission-approved credit should be restored.

Universal Service Cost Allocation and Rates

Q. Please summarize the views of the experts who recommend changes to allocation of universal service costs.

A. OTS expert Mr. Stephen Reed proposes that universal service costs be allocated and recovered in rates on an energy consumption basis.[10] OCA expert Ms. Nancy Brockway also proposes that universal service cost be allocated on an energy consumption basis.[11] AARP's expert Dr. Cooper appears to propose a weighted energy allocator for assigning universal service costs, wherein kWh for non-residential classes are weighted more heavily than residential classes.[12]

Q. What are the tariff implications of these proposed changes on PP&L's tariff?

A. The experts recommending these changes are not specific about how the proposed tariffs should be modified to reflect the changes. The problem is complicated a little by the issue of over- or under-recovery of stranded costs described in the preceding section. Under PP&L's basic proposal, changing the allocation of universal service costs would affect allocated distribution costs. Distribution costs allocated to the residential and GS-1 classes would decline, while costs allocated to other classes would rise. Under the PP&L (and PPLICA) residual CTC approach, the change in allocated distribution costs would then cause a change in transmission/distribution rate charges. Because CTC's are

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[10] Direct Testimony of Stephen M. Reed Office of Trial Staff, 27 June 1997, page 6, lines 1-3.

[11] Direct Testimony and Exhibits of Nancy Brockway Concerning Universal Service Issues, July 1997, page 44 lines 9-12.

[12] Testimony of Dr. Mark N. Cooper on Behalf of American Association of Retired Persons, July 2, 1997, pages 32-33. Note that Dr. Cooper is not specific about how the weights should be established.

computed as a residual, however, these changes would then be offset by an opposite change in the CTC charge for each class. Thus, no class would see any changes in utility service rates. Under the OCA-proposed stranded cost allocation scheme, however, a change in allocated distribution costs would again change transmission/distribution rates, but no offset would occur in the CTC.[13] Thus, under the OCA allocation method (all other factors being equal), the non-bypassable utility rates would decline for residential and GS-1 service and increase for the other rate classes.

Q. **Is changing allocation of universal service costs to an energy allocation scheme justified on a cost causation basis?**

A. No. Universal service costs benefit only residential class customers. On a cost causation basis, universal service costs should be directly assigned only to the residential classes. However, I did not and am not recommending such a change in these proceedings. Many universal services costs are recorded by PP&L in its "Customer Service and Information" account, which is allocated on an unweighted customers basis. That account includes costs incurred for other classes.[14] Thus, I believe that an unweighted customer allocator is generally reasonable for these combined costs on a causation basis. Moreover, the Commission approved that allocation in its decision in R-943271, and the issue was apparently uncontested. If universal service costs were to be directly assigned to the

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[13] Of course, if an increase in allocated universal service costs pushes a class over the rate cap, the CTC must needs be reduced.

[14] In its last base rates proceeding, PP&L had claimed costs for a program designed to help small businesses in its service territory, and allocated those costs via the unweighted customer allocator. The Commission disallowed those costs in its Order in R-9434271 (pages 70 - 71).

residential classes, it would be necessary to go back to other customer service costs and develop a new allocator. I deem that such a scheme would add needless complexity for little gain in the context of this restructuring proposal.

Q. Does the Competition Act require that a change be made in the allocation method for universal service costs?

A. I cannot offer a legal opinion. My interpretation of the spirit of the Act and the Commission filing guidelines is that existing rates and cost allocation methods should be maintained until the various rate caps expire. While §2804(9) of the Act mandates a non-bypassable charge for universal service, the rate cap provisions in §2804(4) constrain changes that can be made in overall rates. Also, judging by the intervenor evidence filed in this case, it seems that cost allocation is not widely viewed as "on the table." Aside from universal service issues, little evidence has been filed about allocating retail jurisdictional costs amongst the rate classes. Moreover, a recent Commission Order indicates that it interprets §2804(7) of the Act as prohibiting intra- or inter-class cost shifting, and it rejects per kWh allocation scheme:

> *"Several commentors support a kwh assessment on all customer classes. We cannot accept this recommendation because it places a disproportionate responsibility for funding universal service and energy conservation programs on high kwh (high volume) users in violation of Section 1301. Further, the Act at §2804(7) prohibits interclass and intraclass cost shifting. Assessing a funding mechanism on kwh use is inconsistent with rate treatments for these programs in recent base rate cases."*[15]

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[15] Pennsylvania Public Utility Commission, Order, Docket No. M-00960890F0010; July 11, 1997.

Q. *Suppose that the Act is interpreted to allow cost shifting and significant room exists* under the rate cap for changes in cost allocation at PP&L. How should the Commission address proposals for changes in cost allocation and inter-class rate design?

A. If cost allocation issues are on the table, they are best addressed after the Commission has determined the magnitude of stranded costs. Because the rate design proposals are significantly constrained by the magnitude of the allowed stranded costs, I suggest that a second proceeding be undertaken for cost allocation. If significant room exists under the cap, I expect that many proposals would come forth for adjusting the cost allocation method and rates. For example, under PP&L's proposal, small business customers are allocated generation, transmission and distribution costs at rates of return well in excess of system average. If room exists under the rate caps, PP&L might use a second proceeding to continue to make progress toward eliminating this historical inequity.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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

EXHIBIT OF

ROBERT D. KNECHT

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

Comparison of Proposed Allocation Schemes for CTC's

PP&L Residual Allocation			*CTC Revenues (millions)*						
	Percent	PV	1999	2000	2001	2002	2003	2004	2005
RS	34.6%	1,309.71	338.41	308.16	267.78	229.98	223.85	216.48	223.73
RWO	0.0%	(0.32)	(0.04)	(0.05)	(0.06)	(0.08)	(0.08)	(0.09)	(0.09)
RW1	0.0%	0.13	0.04	0.03	0.03	0.02	0.02	0.02	0.02
RTD	0.0%	0.51	0.13	0.12	0.10	0.09	0.09	0.08	0.09
RTS	0.6%	22.88	5.57	5.17	4.68	4.57	4.30	3.88	3.59
GS-1	7.2%	274.05	64.04	61.11	56.31	51.96	51.20	49.16	50.14
G1V	0.0%	1.79	0.48	0.43	0.37	0.31	0.30	0.28	0.30
G1C	0.0%	(0.44)	(0.07)	(0.08)	(0.09)	(0.09)	(0.10)	(0.11)	(0.12)
GS-3	27.0%	1,020.68	251.85	234.69	209.36	185.41	180.55	175.82	181.50
G3C	0.0%	0.93	0.26	0.24	0.19	0.18	0.15	0.12	0.11
G3V	0.0%	0.33	0.09	0.08	0.07	0.06	0.05	0.05	0.05
LP-4	14.2%	537.17	133.57	124.09	109.95	97.88	93.93	94.98	91.15
L4C	0.0%	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.00
LP-5	8.0%	303.31	74.56	69.59	62.31	56.38	54.24	52.07	52.27
LP-6	1.4%	54.61	13.81	12.75	11.24	10.08	9.58	9.05	8.96
LPEP	0.3%	11.14	2.69	2.51	2.28	2.07	2.02	1.97	2.00
ISP	0.7%	28.39	7.23	6.69	5.85	5.44	4.99	4.53	4.34
IST	2.9%	109.63	28.77	26.31	22.62	21.18	18.98	16.66	15.33
ISM	0.8%	28.93	7.23	6.71	5.96	5.78	5.21	4.64	4.36
IS1	0.0%	0.07	0.03	0.02	0.01	0.01	0.01	0.00	(0.00)
GH-2	0.4%	14.73	3.49	3.30	3.02	2.78	2.71	2.63	2.67
GH-1	1.5%	56.47	14.10	13.05	11.61	10.29	9.92	9.57	9.78
BL	0.0%	0.64	0.15	0.14	0.13	0.12	0.13	0.11	0.12
S/L	0.3%	11.48	2.87	2.62	2.33	2.10	2.07	1.99	1.95
Total	***100.0%***	***3,786.86***	***949.27***	***877.70***	***776.06***	***686.53***	***664.09***	***643.91***	***652.25***

Sources: Revenues -- OCA-III-39; Discount Rate -- OSBA Statement No. 1 (11.5 percent)

PPLICA Residual Allocation		*($000)*
RS	33.1%	233.88
RTS	0.4%	2.48
RTD	0.0%	0.09
GS-1	6.5%	45.74
GS-3	25.2%	178.29
IS-1	0.0%	0.01
LP-4	13.5%	95.27
IS-P	0.6%	4.42
LP-5	7.6%	53.68
LP-6	7.8%	55.20
IS-T	2.3%	16.52
LPEP	0.3%	2.01
ISA	0.6%	3.97
Standby	0.1%	0.52
GH	1.8%	12.48
BL	0.0%	0.11
SL/AL	0.3%	2.19
Total	100.0%	***706.86***

Source: Exhibit ____ SJB-5

PP&L Allocators	*Generation Level*		*Percents*	
	Demand	***Energy***	***Demand***	***Energy***
RS	2,044.28	11,886.36	38.4%	35.5%
RTS	97.37	424.09	1.8%	1.3%
GS-1	268.66	1,660.72	5.0%	5.0%
GS-3	1,224.07	7,330.15	23.0%	21.9%
LP-4	631.33	4,413.53	11.9%	13.2%
ISP	62.16	442.53	1.2%	1.3%
LP-5,6	470.82	3,418.37	8.8%	10.2%
IST	297.00	2,464.38	5.6%	7.4%
LPEP	23.26	152.92	0.4%	0.5%
ISA	66.29	554.93	1.2%	1.7%
Standby	2.10	11.91	0.0%	0.0%
GH	128.09	590.33	2.4%	1.8%
SL/AL	10.00	114.31	0.2%	0.3%
Total	***5,325.42***	***33,464.55***	***100.0%***	***100.0%***

Source: Exhibit JMK-1

OSBA STATEMENT NO. S1

8/19/97
HBG

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 and Exhibit of

ROBERT D. KNECHT

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

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SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Please state your name and describe your previous involvement in these proceedings.

A. My name is Robert D. Knecht. I filed direct testimony in these proceedings on 2 July 1997 and rebuttal testimony on 5 August 1997, both on behalf of the Pennsylvania Office of the Small Business Advocate.

Q. Please summarize your rebuttal testimony.

A. My conclusions can be summarized as follows:

1 Mr. Schadt claims that I have presented a stranded cost estimate in my direct testimony. I have not. Mr. Schadt therefore cannot use my direct testimony to conclude that the stranded cost estimates of OCA and PPLICA expert witnesses are unreasonable.

2 Mr. Guth's critique of my proposal to use the return on equity discount rate for both stranded costs and CTC revenues is not consistent with finance theory. The weighted average cost of capital (WACC) methodology can only serve as an approximation to theoretically correct discounting methods. In this case, because of the timing difference between stranded cost incurrence and CTC recoveries, the WACC method is a poor approximation.

3 In rebutting my proposal to make the proposed competitive rate design (CRD) optional for GS customers as well as customers, Dr. Tierney and Mr. Krall have ignored significant pieces of my direct testimony and misinterpreted others. Their rebuttal provides no credible reasons for making the CRD mandatory for GS customers.

4 Mr. Kasper's rebuttal arguments regarding my rate design proposals for the GS classes are not consistent with sound rate design principles.

5 Consistent with my direct testimony, Mr. Kasper has expressed willingness to phase out the EDI/IDI credits if the Commission finds that to be allowable under the rate cap provisions of the Act. However, if the credits are retained, Mr. Kasper does not present an economically sound rebuttal case for why PP&L should be allowed to use these credits to reduce competitive entry into its markets during the transition period.

6 In his critique of intervenors' energy price forecasts, Dr. Jones attempts to paint all of the intervenors with one brush. His arguments are not applicable to my direct testimony and therefore do not refute my conclusion that he has used a low-end energy price forecast.

7 In the longer term, market electricity prices can be expected to cycle around the cost of power from replacement capacity. In my direct testimony, I presented an analysis using Dr. Jones' figures demonstrating that his price forecast was insufficient to trigger investment in new capacity by independent producers. Dr. Jones' rebuttal testimony presents an analysis using my methodology. However, in his analysis, he has incorporated new, much more optimistic assumptions than those he used in constructing his direct case and which he provided in response to various interrogatories. When his analysis is corrected for these inconsistencies and other errors, I conclude again that Dr. Jones' electricity price forecasts are insufficient to trigger investment in new generating capacity in PJM. Based on this analysis, Dr. Jones 2016 price forecasts for capacity and energy are about 20 percent below those levels needed to induce new capacity construction in 2005.

8 Professor Kalt and Dr. Jones misunderstand or mischaracterize my direct testimony with respect to a couple of general methodological issues. I rebut their assertions and clarify my direct testimony herein.

These conclusions are addressed in the sections below with corresponding numbers.

1 Stranded Cost Claim

Q. Mr. Schadt's rebuttal testimony contains a chart at page 18 that indicates that the OSBA has submitted a stranded cost estimate of $3.9 billion. Is this correct?

A. No. This is a serious mischaracterization of my direct testimony. Neither I nor the OSBA have submitted a stranded cost estimate in this case. Mr. Schadt therefore cannot use my direct testimony to conclude, as he does at page 19 lines 4 to 8, that the OCA and PPLICA estimates are unreasonable. The $3.9 billion figure from my direct testimony reported by Mr. Schadt at page 18 represents only the impact on PP&L's calculations of changing the discount rate. It does not reflect any other changes that might result from my other conclusions, or from other potential changes in areas that I have not addresssed. As my direct testimony states, PP&L's filing contains other problems which need be corrected before stranded costs can be reasonably estimated. For one, my direct testimony *demonstrates why PP&L's market electricity price forecasts are overly conservative for* the purposes of estimating stranded costs. Thus, for that reason also, PP&L's stranded cost estimate is overstated. However, in my direct testimony, I did not prepare an independent price forecast to input into Mr. Schadt's stranded cost model, and I did not therefore estimate the magnitude of PP&L's "undue conservatism." Nevertheless, that problem exists and should be corrected. Moreover, I have not performed a detailed review and analysis of PP&L's calculations and assumptions in all aspects of its stranded cost calculation. For example, I have not addressed the issue of the reasonableness of including fossil plant decommissioning costs in the stranded cost calculation. Thus, PP&L and Mr. Schadt cannot assume that I deem their calculations to be correct because I have not expressly addressed those issues in my testimony.

2 Discount Rates for Stranded Costs

Q. Mr. Guth criticizes your method for discounting stranded costs. Are his criticisms valid?

A. No. Most importantly, while Mr. Guth makes several criticisms of my analysis, he does not addressed the primary issue. That is, under PP&L's proposed discounting approach, the present value of shareholder returns under deregulation plus full CTC are higher than they would be under continued regulation, when both returns are discounted at the after-tax cost of equity.[1] Even Mr. Guth's Exhibit.LAG-5 which purports to show that my method is incorrect demonstrates how equity holders are better off under deregulation plus CTC than under continued regulation.[2] I do not believe that it is the intent of the Act to allow shareholders to earn a better return under deregulation plus stranded cost recovery than under continued regulation.

Q. At page 24, lines 5 to 15, Mr. Guth indicates that you incorrectly discount debt cash flows at the after-tax cost of equity in Equation (4) of your direct testimony. Is this correct?

A. No, Mr. Guth is simply wrong. He muddles the issue by starting at Equation (4) of my direct testimony. Equation (4) is a reshuffled version of Equation (3), designed to extricate CTC revenues from the other terms. Equation (3) establishes the discounting principle that I use in my analysis. As detailed in my direct testimony, it is based on principles with which PP&L agreed, at least prior to filing rebuttal testimony. If there is an error in Equation (4), it must exist in Equation (3). Similarly, if there is no error in Equation (3), there is no error in Equation (4), since they are algebraically equal. There is no error in Equation (3). For clarity, I include Equations (3) and (4) again in this testimony as Equations (S1) and (S2) below:

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[1] For simplicity in this discussion, I assume that the present value of CTC revenues are set equal to the present value of stranded costs. As noted in my direct testimony, rate cap considerations may preclude full recovery of stranded costs. The rate cap issue, however, does not affect the choice of the correct discount rate.

[2] In Exhibit LAG-5, after-tax returns to equity holders discounted at the equity cost of capital are $57.58 under deregulation plus CTC compared to $56.79 under regulation.

$$(S1) \qquad \sum_{t=1999}^{2045} \frac{Re * E\% * RB_t}{(1+Re)^{(t-1998.5)}} = \sum_{t=1999}^{2045} \frac{(1-T) * (MKTREV_t + CTC_t - O\&M_t - Rd * D\% * RB_t)}{(1+Re)^{(t-1998.5)}}$$

$$(S2) \qquad \sum_{t=1999}^{2045} \frac{CTC_t}{(1+Re)^{(t-1998.5)}} = \sum_{t=1999}^{2045} \frac{O\&M_t + (Rd * D\% + \frac{Re * E\%}{(1-T)}) * RB_t - MKTREV_t}{(1+Re)^{(t-1998.5)}}$$

Equation (S1) contains equity cash flows on both sides of the equation. On the left hand side, returns to equity as allowed under regulation are specified directly as the allowed equity return times the equity component of rate base. On the right hand side, the cash flows are after-tax returns to equity holders. After-tax cash flows to equity holders under deregulation are after-tax revenues minus all costs, including interest. Since both sides of the equation represent cash flows to equity holders, they should be discounted at the equity cost of capital.

Q. **But, by including debt cash flows in the numerator on the right hand side of Equation (S1), aren't you effectively discounting those debt-related cash flows at the cost of equity?**

A. No. Since debt costs are subtracted from revenues and operating costs, the numerator, in aggregate, represents cash flows to equity holders. Equity cash flows, by definition, must be calculated after the debt cash flows have been subtracted out. Thus, the entire numerator term should be discounted at the cost of equity. In one sense, Mr. Guth's error is that he has used the same kind of intuitive logic that he rebuts in other parts of his testimony. For example, as detailed in his algebra in Exhibit LAG-4, Mr. Guth demonstrates that an after-tax discount rate is appropriate for pre-tax cash flows. While it is not intuitively obvious why an after-tax discount rate should be applied to pre-tax cash flows, the logic and algebra in my direct testimony support Mr. Guth's conclusions in this regard. Similarly, just because debt cash flows appear in the numerator of Equation (4), there is no reason to simply assume that the weighted average cost of capital (WACC) discount rate is appropriate. Equations (S1) and (S2) show why the equity cost of capital is the appropriate discount rate for this example.

Q. But, under the adjusted present value method for financial analysis, aren't different cash flows discounted at different rates?

A. Yes. However, Mr. Guth does not appear to advocate an adjusted present value (APV) method. He advocates an approximation to the APV, namely the adoption of a weighted average cost of capital method. Nevertheless, if APV were to be correctly applied to this problem (as opposed to PP&L's approximation method), my conclusion remains correct. Stranded costs and CTC revenues, as computed in PP&L's method, should be discounted at the after-tax cost of equity.

Q. What do you mean when you say that WACC is an approximation to the theoretically correct method of discounting?

A. Equity cash flows should be discounted at the cost of equity. Debt cash flows should be discounted at the cost of debt. Sometimes, for simplicity, financial analysts opt to discount the combined cash flows to debt and equity using an adjusted cost of capital.[3] However, it must be recognized that this technique is an approximation. The present value of after-tax cash flows to debt plus equity holders, discounted at the adjusted cost of capital, is only approximately equal to the sum of the present value of cash flows to debt holders discounted at the cost of debt and the present value of cash flows to equity holders discounted at the cost of equity. Brealey & Myers cite two such approximations, the Modigliani-Miller method and the WACC method.[4] PP&L has chosen the latter. However, analysts recognize that these approximations are precise only under specific circumstances.[5] The WACC is a linear approximation to discounting different cash flows with different rates. However, discounting is not a linear mathematical operation. Thus the WACC is exact only in special circumstances. These circumstances do not obtain in this case.

Q. Can you give an example?

A. Yes. Mr. Guth presents a modified version of my example in his Exhibit LAG-5. His version shows the returns to both debt and equity holders discounted at the WACC, and demonstrates that overall return is the same using PP&L's method. However, as I

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[3] *"Calculating APV is not mathematically difficult, but tracing out and evaluating a project's financial side effects takes financial sophistication. Many firms use a simpler procedure. They adjust the discount rate rather than adjusting present value. This allows them to calculate net present value only once, rather than the tow or more times required by APV. They set the discount rate for project acceptance equal to an adjusted cost of capital which reflects the opportunity cost of capital and the project's financing side effects."* Brealey, Richard and Steward Myers, Principles of Corporate Finance, 1981, page 406.

[4] Ibid., pages 400-418.

[5] *"Like MM's formula, the weighted average formula is only exact when the project is expected to generate a level perpetual cash-flow stream and to support permanent debt."* Ibid. page 414.

mentioned, debt cash flows should be discounted at the debt cost of capital, and equity cash flows should be discounted at the equity cost of capital. The WACC is only an approximation. Therefore, I have added a third column to this example to discount both debt and equity cash flows in the theoretically correct, adjusted present value discounting method. This example is now shown as Exhibit RDK-S1. The example now includes Mr. Guth's WACC approach, the equity only approach, and the adjusted present value approach. Note that the WACC method does not produce the same results as the theoretically correct APV method, because the approximation is not accurate. As shown, both the equity approach and the adjusted present value approach indicate that PP&L's method will improve discounted shareholder returns.

Q. What is your conclusion from review Mr. Guth's rebuttal?

A. Mr. Guth does not demonstrate why equity holders should be better off under deregulation plus CTC than they were under regulation. His analysis shows, however, that the WACC method will accomplish exactly that. Moreover, Mr. Guth does not explain why an approximate method like the WACC should be used in place of the theoretically correct method used in my direct testimony. Thus, I conclude that the appropriate discount rate for both CTC revenues and stranded costs is the after-tax cost of equity.

3 PP&L's CRD Proposal

Q. Dr. Tierney criticizes your proposal to allow the CRD to be optional for GS customers as well as for residential customers. Are her criticisms valid?

A. No. Dr. Tierney indicates that I unfairly portray the CRD proposal as related to economic efficiency only. She then presents her explanation of how PP&L combined all of the accepted rate design criteria into its overall rate design proposal. I believe that to be true for the whole package (not that I necessarily agree with the end result in all areas), and I believe that PP&L used other criteria for deciding to make the CRD optional for residential customers. However, the basic purpose of the CRD, relative to a traditional energy/demand tariff basis, is to move prices closer to marginal cost for economic efficiency reasons. Dr. Tierney describes these considerations in her direct testimony at page 20 line 11 to page 21 line 12.

Q. What other concerns does Dr. Tierney have about making the CRD optional for business customers?

A. Dr. Tierney's major concern appears to be self-selection within each customer class, wherein growing customers choose the CRD option and declining customers choose the traditional option.

Q. At page 30 to 31, Dr. Tierney states: *"OSBA, for example, doesn't mention the likely effect of self-interested selection of rate options by commercial customer on the Company's overall CTC collections when it urges that GS-1 and GS-3 customers, like residential customers, have the option of choosing a rate that has a more efficient rate design."* Is this accurate?

A. No. Dr. Tierney apparently overlooked page 43 of my direct testimony, lines 1 to 12 and footnote 27. Therein, I explicitly describe and evaluate the self-selection issue that she appears to be concerned about. In short, my conclusion was (and is) that PP&L will generally be allowed to recover its stranded costs even with self-interested customer behavior, if the CTC true-up mechanism is allowed.[6] Therefore, her concerns are unfounded.

Q. Are there other issues in your direct testimony regarding the CRD that Dr. Tierney does not address?

A. Yes. Dr. Tierney ignores the potential that a large fixed CTC charge to struggling customers with declining loads could cause or accelerate business closure. Dr. Tierney presents no additional evidence that commercial demand for electricity by PP&L's customers is significantly more price elastic than residential demand. Finally, Dr. Tierney also ignores the obvious discrimination involved in providing the option to residential customers, while denying it to small business customers.

Q. Mr. Krall also criticizes your analysis of the CTC proposal at pages 11 to 12. Can you respond?

A. Mr. Krall indicates that I ignored the strictures of the Act and that it was my conclusion that PP&L engaged in unfair allocations of CTC revenues. I agree with Mr. Krall that stranded costs are, in effect, more than proportionately allocated to the GS classes due to the strictures of the Act, and I stated so in my direct testimony (page 40, lines 5 to 16).

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[6] Note that Dr. Tierney's rebuttal testimony contains a similar inaccurate statement at page 26, lines 4 to 8.

The point in my direct testimony is that the Act's restrictions are inherently unfair to those classes which historically over-recovered costs, because the historical inequities are prolonged. Thus, it was my position that PP&L should consider this unfair treatment as one of its concerns in evaluating whether GS customers should be afforded the "fairness" treatment that is offered to residential customers.

Q. **Mr. Krall also suggests that your proposal to make CRD optional for GS customers will result in higher use-based CTC charges for customers opting for traditional rate design. Is this correct?**

A. It is, but I do not understand how that point argues against making the CRD optional. The higher use-based CTC charges are offset by reduced fixed charges, so focusing only on the energy component is not relevant. Customers will choose the option that combines their concerns about minimizing their overall bill, reducing their risk, and maintains simplicity and understandability of their bills.

Q. **Professor Kalt, at page 67, indicates that a strict usage-based CTC charge will allow price-sensitive customers to avoid the CTC? Is this correct?**

A. No. To fully avoid the usage charges, a customer would need to stop power purchases entirely. Following Professor Kalt's logic, however, existing customers are already paying usage-based charges for stranded costs. Those customers who wish to avoid paying those charges are likely to have already done so.[7]

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[7] PP&L response to OSBA-I-2(c) attached as Exhibit RDK-S8.

4 GS Rate Design

Q. Mr. Kasper rebuts your proposal to maintain a block structure in the delivery charge for GS-1 and GS-3 customers. Do you agree with his arguments?

A. Mr. Kasper argues that a flat delivery charge is "straightforward," "simpler," and "easier to understand." I agree that his proposal meets those criteria. However, other criteria are also important, particularly the accuracy of intra-class cost recovery and intra-class equity. I do not agree that the simplicity criterion should supersede these cost and fairness criteria. PP&L has not demonstrated that phasing out the declining block structure for delivery meets these more important criteria.

Q. What is the purpose of declining block tariffs?

A. Utilities use a declining block tariff structure for two general reasons. First, the customer charge may under-recover customer costs. The first block of the energy charge is then set somewhat higher such that these customer costs are recovered from smaller customers in the customer charge. Second, in many cases, larger customers have higher load factors than smaller customers. The higher charges in the lower blocks serve to reflect the fact that the per-kWh costs to serve low load factor customers are higher than those for high load factor customers.

Q. Does the first criterion apply to PP&L delivery costs?

A. Yes. From Exhibit JMK-2 in the R-00943271 proceeding, customer costs (actual rates of return) are approximately $24 and $49 per customer per month for the GS-1 and GS-3 classes respectively. The proposed customer charges in these proceedings are $7.48 for GS-1 and zero for GS-3. Thus, under PP&L's proposal (all other factors being equal), larger customers within each class will over-recover costs, while smaller customers under-recover costs.

Q. Is this a concern for small businesses?

A. Yes, particularly in the GS-1 class. Typically, the small commercial class includes a set of very small customers that may not be small businesses, including billboards, detached garages, small utility stations, et al. Each of these very small customers attracts customer costs in the cost allocation study. Under PP&L's proposal to phase out the declining block structure, these customers will provide less in revenue than their allocated costs. Larger, small business customers will be obliged to pick up the difference.

Q. Is your second reason for declining block charges a concern for PP&L?

A. As I mentioned in my direct testimony, PP&L has not profferred load research data in these proceedings to justify elimination of the declining block tariff. Please note, however, that I am not arguing that PP&L should have complicated these proceedings by filing load research analysis. My point is that basic changes to the existing tariff should not be undertaken without this analysis.

Q. Can you summarize your position on declining block rates for GS customers?

A. Sound economic reasons exist for a declining block tariff for delivery service. The available evidence on customer costs indicates that a declining block tariff should be maintained for PP&L delivery service. Without better analysis, it is inappropriate to phase out the declining block tariff at this time.

Q. **Please turn now to the issue of PP&L's proposed treatment of the demand charge in the GS-1 tariff. Mr. Kasper's testimony at page 13 states:** ***The first 5 KW of demand for Rate Schedule GS-1 customers who are not demand-metered is part of the delivery charge. The delivery charge for Rate GS-1 customers is composed of a monthly charge of $7.48 and a flat per KWH delivery charge. These delivery service rates were designed to recover the delivery service revenue requirements reflected in PP&L's retail customer rates filed in compliance with the Commission's Final Order at Docket No. R-00943271.*** **Can you respond?**

A. I am not sure how these points refute my direct testimony on this issue. Mr. Kasper's first sentence appears to say that the costs for the first 5 kW of demand for GS-1 customers are included in the delivery charge, while the costs for demand in excess of 5 kW are recovered elsewhere. That was exactly my concern about the PP&L proposal -- an inconsistency exists because of the 5 KW minimum. Mr. Kasper then indicates what PP&L's tariff design for delivery service is, and indicates that it meets the delivery service revenue requirement. Of course, Mr. Kasper describes PP&L's proposal accurately, but I disagree with the proposal. While I agree that PP&L's proposal meets the revenue requirement criterion, my proposal does also. PP&L's proposal for delivery service produces $10.9 million from the customer charge and $44.3 million in the delivery energy charge, a total of $55.3 million. My proposal (to keep the demand charge in the delivery charge and exclude it from the capacity and energy rider) produces $10.9 million from the customer charge, $8.9 million from the delivery demand charge and $35.5 million from the blocked delivery energy charge, a total of $55.3 million.

Q. Can you briefly restate your concern about PP&L's treatment of the demand charge in the proposed GS-1 tariff?

A. The existing tariff contains an explicit demand charge that is applied only to demand in excess of 5 KW. This type of tariff makes sense for PP&L when it is combined with PP&L's minimum billing kW, blocked (kWH per kW) energy charges. The structure of the blocked energy charges combined with the minimum billing level adjusts for the demand charge above 5 kW. However, in unbundling, PP&L has separated the demand charge from the blocked energy charges. By combining a demand charge for billing kW above the 5 kW minimum with a flat energy charge in the Capacity and Energy Rider, the PP&L proposal provides a greater discount for larger customers than for smaller customers of the same load factor. In PP&L's methodology, smaller GS-1 customers (below 5 kW) will only select alternative generation if the competitor can provide energy at or below the energy-only component of the Capacity and Energy Rider. Since that value is based on the energy price forecast and excludes capacity prices, it is unlikely that small GS-1 customers will be able to opt for alternative generation. My proposal mitigates this problem.

5 EDI/IDI Credits

Q. Mr. Kasper indicates that PP&L is willing to phase out the EDI/IDI riders per the established schedule if the Commission allows such a phase-out within the rate cap (page 12, lines 4-8). Is this statement consistent with your direct testimony?

A. Yes.

Q. Assume, for the moment, that the EDI/IDI credits must be continued through the transition period. At pages 11 to 12, Mr. Kasper argues: *[T]hese riders, provisions and rate schedules are all generation related. Once a customer chooses an alternative supplier, that customer is no longer buying Basic Utility Supply Service, including PP&L's generation supply resources. The continuation of these riders, provisions and rate schedules is not logical in this situation, and is not fair to other customers who receive service under these rate schedules as their circumstances change.* Do you agree?

A. No. Mr. Kasper chooses to link EDI/IDI credits to BUSS because they are generation-related. However, it is at least as logical to link EDI/IDI credits to stranded costs, which, to a great extent, are also generation-related. There is no particular reason why the BUSS rates that are based on market price forecasts are more generation-related than stranded costs, which reflect the historical sunk costs of generation that are in excess of the market price forecasts. If EDI/IDI credits are linked to stranded costs, all currently eligible customers should remain eligible in the future, since the CTC's are non-bypassable. As I mention in my direct testimony, this result has the added benefit of not discouraging entry and competition in PP&L's service territory.

Q. Why do you suggest that linking EDI/IDI to stranded costs may be more reasonable than attaching them to BUSS?

A. In the past, the goal of the economic development riders was to attract customer load that could not afford to make its full contribution to fixed costs based on fully allocated costs, but would provide a contribution in excess of incremental costs to the benefit of all other ratepayers. In the future, this motivation is analogous to retaining load that will provide some contribution to stranded cost recovery, but not a full recovery. While conceptual and numerical differences exist, future market prices are akin to historical incremental costs, since they are dominated by PJM marginal costs. Thus, the future CTC is akin to the historical sunk cost above incremental cost, which was the piece that was discounted by EDI/IDI. Thus, the historical EDI/IDI credits can be seen as a discount to historical stranded costs. Given this parallel, it makes more sense to link these credits to stranded costs than to BUSS service.

6 Fuel Price Forecasts

Q. Has Dr. Jones accurately assessed your critique of his fuel price forecasts?

A. No. In his rebuttal testimony at page 41, lines 1-5, Dr. Jones states *[t]he starting point problem is due to intervenors' witnesses use of an out-of-date forecasted range of change for fuel prices that was subsequently applied to actual 1996 energy prices. This starting-point problem shifts all forecasted prices up by the magnitude of the error as noted in Exhibit STJ-12.* While Dr. Jones' critique may possibly apply to other intervenors, it does not apply to mine. In Tables 1, 2 and 3 of my direct testimony I applied Dr. Jones' price escalation forecasts to the actual 1996 levels, to compute nominal prices in various years. I then took the forecast price levels (not escalation rates) from the various sources and adjusted them into nominal dollars using Dr. Jones' inflation forecast. Thus, I compared nominal forecast price levels on a consistent basis, and did not apply pre-1996 escalators to higher 1996 base prices as Dr. Jones suggests.

Q. What was the conclusion of your initial review of Dr. Jones' fuel price forecast?

A. Based on a comparison of Dr. Jones' forecasts with other independent forecasts of fuel costs, I find that his forecasts are generally in the lower end of the range of independent forecasts. Since Dr. Jones' criticism does not apply to my analysis, I have not changed my conclusion.

Q: Are Dr. Jones' rebuttal arguments consistent with the methodology stated in his direct testimony?

A: No. In his direct testimony (page 39, lines 2-8), Dr. Jones states, *[m]y knowledge of energy forecasting methods leads me to review a number of forecasts, not just one forecast, when arriving at a view of energy price trends. Additionally, I examined the recent historical record for price behavior in assessing the short-to-intermediate term forecasts of others.* This method contrasts with his rebuttal testimony (page 47, lines 1-5), in which Dr. Jones states, *[i]n fact, I considered forecast assumptions that drove high, base case and low fuel price scenarios, but in order to present the Commission with a reliable, long-term market price forecast, I was guided mainly by actual changes in oil and gas prices during this century.* Adding to the confusion, Dr. Jones' rebuttal testimony criticizes the accuracy of forecasts made by DRI, EIA and other forecasting entities,[8] upon which he appeared to rely in his direct testimony.

Q. Does Dr. Jones present a thorough analysis of historical changes in oil prices?

A. It would be more accurate to say that Dr. Jones analyzes selective historical changes in oil prices. By eliminating the price spike caused by the Iranian Revolution, Dr. Jones effectively assigns a zero percent likelihood to a similar price spike in the next twenty years. Dr. Jones provides no analysis supporting this decision to exclude certain data observations.

Q. Please summarize Dr. Jones' assessment of the trend in oil prices.

A: In Exhibit STJ-16 of his rebuttal testimony, Dr. Jones charts U.S. average annual wellhead prices since 1900. Dr. Jones states that *[a]s illustrated in Exhibit STJ-16, once oil prices are adjusted for inflation and for the unprecedented price spike caused by the Iranian revolution (but including price increases caused by the recent Gulf War and the original Arab Embargo), oil prices have fluctuated in a reasonably narrow range about a flat real price trend of $15.50/Bbl (1996$)* (page 47, lines 8-13).

Q. Is it possible to test this conclusion?

A. Yes. If, in fact, oil prices have exhibited a flat real trend over long periods of time, than the average real price over time should remain reasonably constant.

Q. Does Dr. Jones evaluate the trend in average oil prices over time?

A. No. Dr. Jones performs a static analysis, calculating the average price over a single period of time (1900-1996). Calculation of a single average price over this time period

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[8] See, for example, Dr. Jones' rebuttal testimony at pages 56 to 59.

provides no information about the trend in average prices (i.e., are they increasing, decreasing or constant). Dr. Jones does not address trends in the average price of oil in either his direct or rebuttal testimony.

Q. Have you examined the trend in average oil prices over time?

A. Yes.

Q. What are the results of your analysis?

A. I present my analysis both graphically and statistically. Dr. Jones Exhibit STJ-16 is misleading, in that the observations are plotted linearly and include the huge price spike that he subsequently excludes from his analysis. In Exhibit RDK-S2, I have replotted the real crude oil price data from with a log-linear scale to better depict long-term time percentage trends. I have included a trend line that was calculated by excluding the data in the price spike. Thus, even ignoring the Iran price spike, real crude oil prices have trended upwards, at an average annual rate of 0.8 percent. Moreover, prices have behaved in a stair step fashion, bouncing up and then drifting down.

Q. Can this result be seen in Dr. Jones' rebuttal testimony?

A. Yes. A careful inspection of Exhibit STJ-16 shows that real oil prices from the mid-1920s through the early 1970s were most often below or very close to the 96-year average of $15.50 calculated by Dr. Jones. Since the early 1970s, real prices have consistently been above this average. Thus, the distribution of real oil prices around the historical average has not been random; for approximately the last 25 years, prices generally have been above the historical average. For the prior 50 years, prices were most frequently below or close to Dr. Jones' average. Dr. Jones figures confirm this conclusion. Dr.

Jones, at page 54 lines 9 to 11, indicates that the average real price over the last ten years was $17.90 per barrel, compared to the full period average of $15.50. Thus, Dr. Jones' figures confirm the point that the average real oil prices in more recent periods has been substantially higher than his historical average.

Q. What are the implications of this result?

A. As shown in Exhibit RDK-S2, the historical data show that real prices of crude oil are higher now than in the first half of the century. While increases do not follow an obvious trend pattern, they are certainly not flat. A trend regression, even excluding the data points that Dr. Jones deems to be unreliable, indicates that real prices have drifted upward over the long term.

Q. Do you have any concerns with Dr. Jones' analysis of the historical correspondence between real gas, oil and coal prices?

A. Yes. In his rebuttal testimony (page 28, lines 11-15), Dr. Jones states *[h]istorically, the correlation coefficients are 0.92 between (real) gas and coal prices, 0.9 for oil and coal, indicating that there is no real-world precedent for a sustained and growing gap between competing fuels.* However, Dr. Jones' conclusion is not supported by his use of the correlation coefficient measure. High correlation coefficients can be associated with an increasing, constant, or decreasing gap between variables. Exhibit RDK-S3 shows three examples of time series trends, with increasing, decreasing and constant gaps (in both absolute and percentage terms), all of which have correlation coefficients of unity. Thus, Dr. Jones' conclusion is not supported by his analysis.

7 Market Price Forecast Sufficiency

Q. Mr. Knecht, in your direct testimony, you presented an analysis of the equity return that an IPP investor would expect from investing in a natural gas fired combined cycle plant in PJM, using Dr. Jones' forecasts and replacement cost assumptions. Why is this analysis relevant?

A. To my mind, this analysis is the critical test of a forecast's reasonableness. The analysis looks at the problem from the point of view of a potential investor, and therefore addresses the entire economic life of a facility.[9] If the forecast is reasonable, the returns to equity holders should approximate the cost of equity capital. When investors consider new projects, and market price expectations produce a return that is well in excess of the cost of equity capital, these investors will construct capacity and these economic rents will disappear.[10] If, however, market expectations produce an inadequate return, no capacity will be added until price expectations firm.

Q. Has Dr. Jones applied this methodology to his price forecast?

A. In his rebuttal testimony, he has. He concludes that his price forecast is sufficient to provide adequate returns to IPP investors.

Q. Why does his conclusion differ from your own?

A. In the analysis in my direct testimony, I relied on the assumptions provided by Dr. Jones

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[9] Note that I agree with Dr. Jones rebuttal testimony (page 80, lines 3 to 4) that market prices do not need to be sufficient to provide a full expected return to equity holders in every year of the forecast period. The price and cost expectations need to be sufficient to provide an adequate return over the life of the asset.

[10] As noted in my direct testimony, capacity additions are lumpy and timed sub-optimally, causing price fluctuations around the replacement cost, both above and below.

and the best information that was available to me for those parameters that Dr. Jones did not provide. The primary reason for the difference in conclusions is that, in his rebuttal analysis, Dr. Jones has changed many of his key assumptions. He has also made a couple of corrections and adjustments to my analysis, some of which have merit.

Q. What changes have you made in your analysis to reflect Dr. Jones' rebuttal testimony?

A. Time and resource constraints precluded a detailed review of all of Dr. Jones' changed assumptions. However, I have used my judgment to incorporate those changes which I believe are reasonable. The revised analysis is presented in Exhibit RDK-S4. Based on this analysis, I again conclude that Dr. Jones' price forecast is too conservative and is insufficient to induce sufficient capacity additions to meet demand plus the PJM reserve margin requirement.

Q. Please detail the differences in the assumptions between your analysis and Dr. Jones'.

A. The following list describes each assumption used in the analysis that Dr. Jones has either changed or corrected:

- Capital Costs and Heat Rates: In his direct case, Dr. Jones uses a capital cost assumption of $595 (96$) per kW and a heat rate of 7000 btu/kWh.[11] In his rebuttal, Dr. Jones has analyzed a number of different scenarios, with capital costs ranging from $470 to $580 per kW, and heat rates ranging from 5830 to 6750. Using simple averages, Dr. Jones has reduced his key cost parameters from $595 per kW and 7000 btu/kWh, to $536 and 6186 respectively. In effect, for this analysis, he has reduced capital costs by 12 percent from those used in his price modelling, and improved efficiency by 10 percent. Needless to say, changing assumptions in mid-stream reduces confidence in the accuracy

[11] See OCA-III-49 and OCA-III-74, in Exhibit RDK-S6.

of the assumptions. However, Mr. Falkenberg has also presented capital cost and heat rate assumptions, from the same source. By approximating his Exhibit ____ (RJF-6), his data show a mid-point of $575 per kW[12] and 7000 btu/kWh. Mr. Falkenberg's assumptions are therefore reasonably close to Dr. Jones' original estimates. Since I have no expert power plant engineering expertise at hand, I split the difference in my analysis. In Exhibit RDK-S4, I have used base level of $555 per kW and a heat rate of 6593. Note that these assumptions are much more optimistic than those used by Dr. Jones in his direct case.

- Delivered Natural Gas Cost: Dr. Jones assumes a delivered natural gas cost in 2000 of $2.30 per mmbtu, which he escalates at 2.5 percent per year. He assigns no gas transmission costs to a new plant in PJM. In my direct testimony, I generally used Dr. Jones' assumptions for the wellhead cost of gas, although I included a conservative estimate for gas transmission costs. As described earlier, Dr. Jones has used a conservative forecast for wellhead gas prices. Thus, for this analysis, I assume that the 2015 wellhead price for gas we be at the average of the EIA, AGA, and DRI forecasts presented in my direct testimony.[13] To meet this target, gas prices remain flat until 1999 and increase at 3.0 percent per year to 2015. Beyond that, I used Dr. Jones' 2.5 percent per year escalation assumption. For gas transmission costs, I note that the EIA reports that the 1996 wellhead price of gas was $2.25 per mcf, while average delivered cost to utilities was $2.69 per mcf. Also, the UGI Utilities, Inc. (Gas Division) has a very favorable transportation tariff (XD-F) for large volume gas users at a marginal cost of $0.55 per mcf. As an approximation for transmission costs, I assume $0.50 per mmbtu in this analysis, escalating with Dr. Jones' inflation forecast.

- O&M Costs: Dr. Jones has increased his O&M cost estimates, from those provided in earlier interrogatory responses, possibly to reflect Mr. Falkenberg's comments and possibly to account for maintenance capital expenditures (which he excludes from his analysis). I have adopted Dr. Jones' revised figures. For my analysis, I have excluded maintenance capital investments, under the assumption that Dr. Jones' revised values reflects such costs. Nevertheless, the assumptions that all such investments are tax deductible and are included in O&M estimates are optimistic for this type of project analysis.

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[12] Note that I have applied the 15 percent "soft cost" estimate to Mr. Falkenberg's values to be consistent with Dr. Jones adjustment to his figures.

[13] See Table 1 at page 28. Note that these forecasts were developed using Dr. Jones' inflation forecast of 2.5 percent per annum.

- O&M and Capital Cost Escalators: In the analysis in my direct testimony, I was unsure whether the values provided by Dr. Jones in his interrogatory responses represented 1996 costs or 2000 costs. To be conservative in that analysis, I assumed that his figures were 2000 costs. In his rebuttal analysis, however, Dr. Jones implies that his values were 1996 values. I have adjusted my escalators accordingly.

- Capacity Factors: In my direct testimony, I used capacity factors based on the mid-point of the capacity factors for combined cycle plants reported by Dr. Jones in response to Environmentalists Interrogatory Set 4 number 207 (Exhibit RDK-S7).[14] In his rebuttal analysis, Dr. Jones uses values that are generally at the very high end of his reported range. I disagree with Dr. Jones that the high end of the range is appropriate for this analysis. The question is not whether the lowest cost combined cycle unit is profitable -- it is whether prices are sufficient to induce all of the capacity additions that are need to meet the pool reserve margin requirement. Thus, if anything, the low end of the range is the appropriate measure. However, for the analysis in Exhibit RDK-S4, I have retained my original assumptions.

- Depreciation: Dr. Jones uses a 20-year 150 percent declining balance method for depreciation, which is more accurate than the simple 30 year straight-line method that I used in my direct testimony. I have adopted Dr. Jones' method.

- Debt Cash Flows: Dr. Jones' analysis contains an error with respect to debt cash flows, although the numerical impact is relatively minor. In his cash flow analysis, Dr. Jones assumes a levelized annual debt repayment, while in his interest cost line, he assumes that debt balances drop much faster than in his repayment line. Thus, he either understates debt repayments or understates interest costs. I have treated these cash flows consistently in Exhibit RDK-S4.

- Working Capital: Dr. Jones prepared two analyses, one including working capital and one without. A new generator will obviously require working capital, and I see no reason to exclude such costs. Based on Exhibit JMK-2, I calculate that PP&L's working capital requirement for 1995 for its generation business was about 9.5 percent of the revenue requirement. To be optimistic, I apply only 5 percent in this analysis.

- Contingency and Rate of Return: Both Dr. Jones and I assume a 12.5 percent rate of return, with no contingency assigned to the capital cost estimate. A 12.5 percent return on equity for an investment in a reasonably risky venture

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[14] In my direct testimony, I inadvertently referenced this source as Environmentalists-4-205. I apologize for any confustion caused thereby.

is quite low.[15] These are very optimistic assumption from a project evaluation standpoint. It is common for project financial analysts to include either a contingency estimate for the capital cost of construction or a required rate of return in excess of the cost of capital, to adjust for the natural optimism of vendors, project cost estimators, operators, etc..

Q. **Can you summarize your conclusions from your second pass at this analysis?**

A. Using the assumptions detailed above, I conclude that Dr. Jones' price forecast is insufficient to provide an adequate return to an independent power plant investor. Using assumptions that I believe are generally optimistic for adopting the project, Exhibit RDK-S4 shows that the present value of the project based on Dr. Jones' price forecast is negative $89 million on an equity investment of $207 million.

Q. **What price forecast is necessary to induce investment in a combined cycle facility in 2005?**

A. Many different price forecasts will be sufficient. However, for demonstration purposes, I start with Dr. Jones' capacity and energy price forecasts in 2005 and determine the escalation rates necessary for each price forecast to produce a zero NPV project. (Note that a zero NPV project provides an equity return equal to the equity cost of capital, 12.5 percent. At zero NPV, prices are just high enough to induce an entrant with a required RoE of 12.5 percent.) These escalation rates are applied only through 2016 (the end of Dr. Jones' forecast), after which the 2.5 percent inflation figure is applied. The individual escalation rates for capacity and energy are designed to keep Dr. Jones' forecast relationship between the two components relatively constant. This analysis is shown in

[15] For example, using Mr. Moul's risk-free and market premium rate parameters, a 12.5 percent rate of return implies a CAPM beta of 0.82, a value that is below that of most industrial commodity companies. (See Direct Testimony of Paul R. Moul, Exhibit PRM-1, page 6.)

Exhibit RDK-S5. From this exhibit, I conclude that escalating Dr. Jones' 2002 energy forecast at nominal rates of 4.6% per year and his capacity forecast at 2.8% per year will produce a zero net present value project. In the year 2016, my break-even capacity price forecast is $74 per kW per year, and the energy forecast is $45 per MWh. Both values are a little more than 20 percent above Dr. Jones' forecast.

Q. Can you respond to Dr. Jones' argument that you have ignored the efficiencies associated with competition?

A. First, as described in detail above, I have used assumptions that I believe are generally optimistic. As such, the optimistic assumptions incorporate some of the potential efficiencies. Second, Dr. Jones' arguments about continuous improvements in heat rates and other operating costs are not internally consistent with the assumptions in this analysis. As I noted earlier, *for capacity to be sufficient, the price forecast must be sufficient to support the marginal capacity addition.* Thus, prices must be sufficient to support the first set of combined cycle units that come on stream at their efficiencies and operating cost levels. If the industry expects plant efficiencies continue to improve, the investors in the first set of units will expect to operate at lower capacity factors in the outlying years.[16] Thus, if I were to forecast continuous improvements, I should also assume lower capacity factors in outlying years. Third, Dr. Jones suggests that competition can cause continuous improvements in efficiency. As an economist, I agree. However, competitive market forces cannot alter the principles of thermodynamics.

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[16] The more efficient plants will be able to successfully bid into the market for a greater percentage of hours than less efficient plants.

Efficiency gains of the magnitude of those achieved by converting from single cycle steam plants to combined cycle plants simply cannot be replicated without violating the laws of physics. As efficiencies get closer to theoretical maxima, efficiency gains are increasingly difficult to come by.

8 Miscellaneous Issues

Q. In rebutting your direct testimony, Professor Kalt takes issue with your statement that PP&L could price utility generation service below market levels, indicating that PP&L will price its generation in this way (pages 49-50). Is his criticism valid?

A. No. As I described earlier, PP&L establishes its CTC as a residual calculation, by backing out a market price forecast. As noted in my direct testimony, I believe that PP&L's market price forecast is unduly conservative. By under-forecasting market prices, PP&L locks in higher CTC's during the transition period. If actual market prices exceed the forecast market prices, PP&L will be constrained by the rate cap from increasing its generation service prices, and therefore will effectively price its own generation at below market rates. I do not believe that PP&L has proposed to reduce its CTC's if market prices rise above forecast, as Professor Kalt's testimony would suggest.

Q. At page 33, Dr. Jones indicates that you propose divestiture as a means for evaluating the stranded asset costs. Is this accurate?

A. No, Dr. Jones misinterprets my direct testimony. As detailed on pages 33 to 34 therein, I make two points. First, PP&L's stranded costs could be determined by plant divestiture values. I did not say that PP&L's stranded costs should be determined by divestiture.

While I believe that there are benefits to divestiture in terms of promoting entry and competition and in improving the accuracy of stranded cost determination, I tend to agree with Dr. Jones that divestiture is not mandated by the Act and that "fire sale" required divestiture would cause a host of problems. My second point was that PP&L retains the option to divest some or all of its generating plants, and thereby achieve the market value of the plant. A successful bidder for PP&L's plants would tend to use optimistic assumptions about market prices, operating costs, etc., or it wouldn't be the successful bidder. Therefore, the Commission should rely on relatively optimistic assumptions about the market value of PP&L's plants for determining stranded costs. Nowhere in my direct testimony do I recommend that the Commission mandate divestiture, and Dr. Jones' rebuttal is irrelevant.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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

EXHIBIT OF

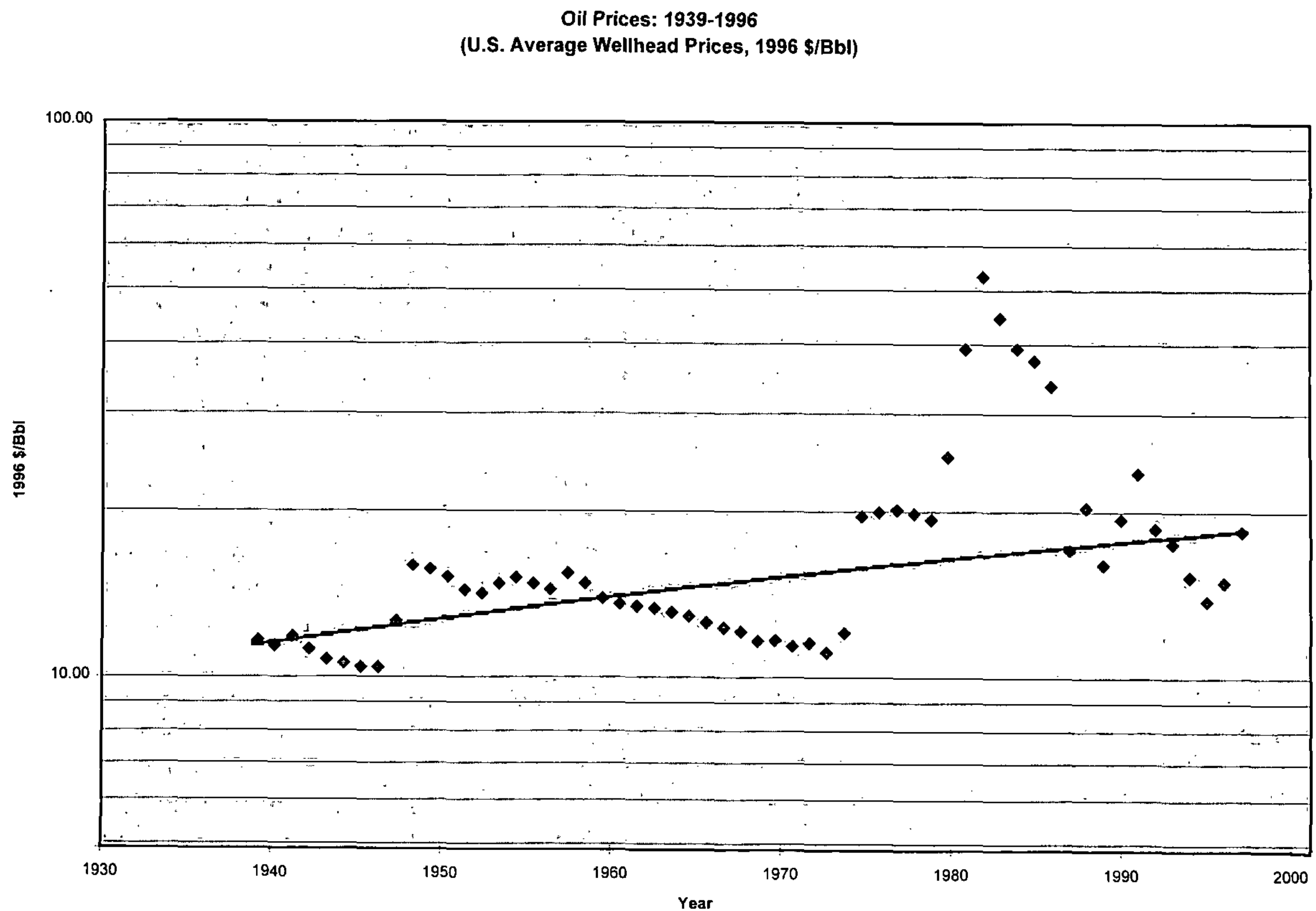
ROBERT D. KNECHT

ON BEHALF OF THE

OFFICE OF SMALL BUSINESS ADVOCATE

Example for Stranded Cost Discount Rates: WACC, Equity and APV Methods					
	Guth WACC	RDK Equity			
	NPV1 @ 8%	*NPV1 @ 12%*	*APV*	*Period 1*	*Period 2*
Earnings under Regulation					
O&M Costs				$ 75.00	$ 75.00
Debt Costs	$ 28.89		$ 29.11	$ 15.00	$ 15.00
Income Taxes				$ 20.00	$ 20.00
Equity Return (after-tax)	$ 57.78	*$ 56.79*	$ 56.79	***$ 30.00***	***$ 30.00***
Revenue Requirement	***$ 86.67***		***$ 85.89***	***$ 140.00***	***$ 140.00***
Stranded Cost/CTC at WACC					
Market Revenues				$ 100.00	$ 100.00
Stranded Costs	$ 77.04			$ 40.00	$ 40.00
CTC Revenues	$ 77.04			$ 77.04	
Earnings under Deregulation plus CTC					
Market Revenues				100.00	100.00
CTC Revenues				77.04	-
O&M Costs				(75.00)	(75.00)
Debt Costs	$ (28.89)		$ 29.11	(15.00)	(15.00)
Income Taxes				(34.81)	(4.00)
Equity Return (after-tax)	$ 57.78	*$ 57.58*	$ 57.58	*52.22*	***6.00***
	$ 86.67		***$ 86.69***		
Notes:					
1) All NPV's are computed as of the middle of Period 1.					
2) CTC Revenues are determined by the NPV of CTC Costs					
3) Income tax rate is 40 percent					
4) Implied return on debt in example is:		6.31579%			
5) Implied debt share of capital is:		*48.72%*			

EXHIBIT RDK-S2



Note: Trendline does not include 1979-1985 price data

EXHIBIT RDK-S3

CORRELATION COEFFICIENT EXAMPLES

	Observation						Correlation Coefficient	Gap
	1	2	3	4	5	6		
A	1.10	1.20	1.10	1.40	1.50	1.60	1.00	Increasing
B	1.10	1.11	1.12	1.13	1.14	1.15		
C	2.0	2.1	2.0	1.9	2.2	2.3	1.00	Constant
D	1.0	1.1	1.0	0.9	1.2	1.3		
E	2.00	2.01	2.02	2.01	2.03	2.04	1.00	Decreasing
F	1.00	1.20	1.40	1.20	1.60	1.80		

Price Sufficiency for New Combined Cycle Capacity -- PP&L Price Forecast

Inflation	2.50%	Fixed O&M (97 $/kW/year)	$ 9.00	Maintenance Capital	0.0%	of book value
Capacity (MW)	512.00	Variable O&M (96 $/MWh)	$ 3.10	Working Capital	5.0%	of revenues
Capital Cost (96$/kW)	$ 555.00	Capacity Factor		Income Tax Rate	41.5%	
Wellhead Fuel Cost (96 $/mmbtu)	$ 2.20	Debt Cost	8.0%	Decommissioning	10.0%	of real investment cost
Gas Transmission (96 $/mmbtu)	$ 0.50	Debt Share	38.6%	Sources:	OCA-III-49, OCA-III-74, STJ-3, STJ-4, STJ-7, STJ-8, JRS-1	
Heat Rate (btu/kWh)	6,593				Environmentalists-4-207, UGI-Gas XD tariff, JMK-2, PPLICA-VIII-12	
					S.T. Jones Rebuttal Testimony	

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2030	2034
Capacity Factor		53.5%	53.0%	62.0%	62.5%	66.0%	67.5%	72.0%	60.5%	72.5%	74.0%	73.0%	73.0%	73.0%	73.0%
Capacity Price ($/kW/year)		44.0	45.0	50.0	51.0	53.0	54.0	55.0	56.0	57.0	59.0	60.0	67.3	86.2	95.1
Energy Price ($/MWh)		26.0	27.0	29.0	30.0	31.0	32.0	32.0	33.0	35.0	35.0	36.0	40.8	52.3	57.7
Generation (GWh)		2,400	2,377	2,781	2,803	2,960	3,027	3,229	2,713	3,252	3,319	3,274	3,274	3,274	3,274
Capacity Revenues ($mm)		22.53	23.04	25.60	26.11	27.14	27.65	28.16	28.67	29.18	30.21	30.72	34.47	44.13	48.71
Energy Revenues ($mm)		62.39	64.18	80.64	84.10	91.77	96.88	103.34	89.55	113.81	116.16	117.87	133.72	171.17	188.94
Revenues		***84.92***	***87.22***	***106.24***	***110.21***	***118.90***	***124.53***	***131.50***	***118.22***	***142.99***	***146.37***	***148.59***	***168.19***	***215.30***	***237.65***
Fuel Cost ($/mmbtu)	3.00%	2.63	2.71	2.79	2.87	2.96	3.05	3.14	3.23	3.33	3.43	3.53	4.00	5.12	5.65
Fuel Costs ($/MWh)		17.33	17.85	18.39	18.94	19.50	20.09	20.69	21.31	21.95	22.61	23.29	26.35	33.73	37.23
Gas Transmission Cost ($/MWh)		4.12	4.22	4.33	4.43	4.54	4.66	4.77	4.89	5.02	5.14	5.27	5.96	7.63	8.42
Vble O&M Costs ($/MWh)		3.54	3.63	3.72	3.82	3.91	4.01	4.11	4.21	4.32	4.43	4.54	5.13	6.57	7.25
Fixed O&M Costs ($/kW/year)		10.97	11.24	11.52	11.81	12.10	12.41	12.72	13.03	13.36	13.69	14.04	15.88	20.33	22.44
Fuel Costs ($mm)		51.46	52.46	63.15	65.51	71.19	74.92	82.24	71.11	87.69	92.11	93.50	105.79	135.42	149.48
Variable O&M Costs ($mm)		8.51	8.64	10.36	10.70	11.58	12.14	13.27	11.43	14.04	14.69	14.86	16.81	21.52	23.75
Fixed O&M Costs ($mm)		5.61	5.75	5.90	6.05	6.20	6.35	6.51	6.67	6.84	7.01	7.19	8.13	10.41	11.49
Decommissioning															70.85
Total Operating Costs ($mm)		***65.58***	***66.85***	***79.41***	***82.26***	***88.97***	***93.42***	***102.02***	***89.22***	***108.58***	***113.81***	***115.55***	***130.73***	***167.35***	***255.57***
Depreciation - Original ($mm)		25.33	23.43	21.68	20.05	18.55	17.16	15.87	14.68	14.48	14.48	14.48	14.48	-	-
Depreciation - Incremental ($mm)															
Interest ($mm)		10.43	10.08	9.74	9.39	9.04	8.69	8.34	8.00	7.65	7.30	6.95	5.22	1.74	0.35
Income Taxes ($mm)		(6.82)	(5.46)	(1.90)	(0.62)	0.97	2.18	2.18	2.62	5.10	4.47	4.82	7.37	19.18	(7.58)
Net Income		(9.61)	(7.69)	(2.68)	(0.87)	1.37	3.08	3.08	3.70	7.19	6.31	6.79	10.39	27.04	(10.69)
Capital Expenditures	(337.78)	-	-	-	-	-	-	-	-	-	-	-	-		
EOY Book Value	337.78	312.44	289.01	267.33	247.28	228.74	211.58	195.71	181.04	166.55	152.07	137.59	65.17	(0.00)	(0.00)
EOY Debt	130.38	126.04	121.69	117.34	113.00	108.65	104.31	99.96	95.61	91.27	86.92	82.58	60.84	17.38	0.00
Working Capital		4.25	4.36	5.31	5.51	5.95	6.23	6.57	5.91	7.15	7.32	7.43	8.41	10.77	11.88
Cash Flow															
Net Income		(9.61)	(7.69)	(2.68)	(0.87)	1.37	3.08	3.08	3.70	7.19	6.31	6.79	10.39	27.04	(10.69)
Depreciation		25.33	23.43	21.68	20.05	18.55	17.16	15.87	14.68	14.48	14.48	14.48	14.48	-	-
Capital Expenditures	(337.78)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Cash Flow	130.38	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)
Working Capital		(4.25)	(0.12)	(0.95)	(0.20)	(0.43)	(0.28)	(0.35)	0.66	(1.24)	(0.17)	(0.11)	(0.21)	8.84	9.75
Net Cash Flow	(207.40)	7.13	11.28	13.70	14.64	15.14	15.61	14.25	14.70	16.09	16.27	16.82	20.33	31.53	(5.28)
Internal Rate of Return	7.1%														
2004 NPV @ 12.5%	($88.84)														

Note: Some columns are hidden for reporting purposes.

Price Sufficiency for New Combined Cycle Capacity -- Zero NPV

Inflation	2.50%	Fixed O&M (97 $/kW/year)	$ 9.00	Maintenance Capital	0.0% of book value
Capacity (MW)	512.00	Variable O&M (96 $/MWh)	$ 3.10	Working Capital	5.0% of revenues
Capital Cost (96$/kW)	$ 555.00	Capacity Factor		Income Tax Rate	41.5%
Wellhead Fuel Cost (96 $/mmbtu)	$ 2.20	Debt Cost	8.0%	Decommissioning	10.0% of real investment cost
Gas Transmission (96 $/mmbtu)	$ 0.50	Debt Share	38.6%	Sources:	OCA-III-49, OCA-III-74, STJ-3, STJ-4, STJ-7, STJ-8, JRS-1
Heat Rate (btu/kWh)	6,593				Environmentalists-4-207, UGI-Gas XD tariff, JMK-2, PPLICA-VIII-12
					S.T. Jones Rebuttal Testimony

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2030	2034
Capacity Factor		53.5%	53.0%	62.0%	62.5%	66.0%	67.5%	72.0%	60.5%	72.5%	74.0%	73.0%	73.0%	73.0%	73.0%
Capacity Price ($/kW/year)	2.84%	54.4	55.9	57.5	59.1	60.8	62.6	64.3	66.2	68.0	70.0	72.0	81.7	104.6	115.4
Energy Price ($/MWh)	4.64%	27.5	28.8	30.1	31.5	33.0	34.5	36.1	37.8	39.5	41.4	43.3	50.0	64.0	70.6
Generation (GWh)		2,400	2,377	2,781	2,803	2,960	3,027	3,229	2,713	3,252	3,319	3,274	3,274	3,274	3,274
Capacity Revenues ($mm)		27.84	28.63	29.45	30.28	31.14	32.03	32.94	33.87	34.84	35.82	36.84	41.82	53.54	59.09
Energy Revenues ($mm)		65.98	68.40	83.73	88.32	97.59	104.44	116.57	102.50	128.53	137.27	141.70	163.67	209.51	231.26
Revenues		***93.83***	***97.03***	***113.17***	***118.60***	***128.74***	***136.47***	***149.51***	***136.37***	***163.36***	***173.10***	***178.55***	***205.49***	***263.05***	***290.36***
Fuel Cost ($/mmbtu)	3.00%	2.63	2.71	2.79	2.87	2.96	3.05	3.14	3.23	3.33	3.43	3.53	4.00	5.12	5.65
Fuel Costs ($/MWh)		17.33	17.85	18.39	18.94	19.50	20.09	20.69	21.31	21.95	22.61	23.29	26.35	33.73	37.23
Gas Transmission Cost ($/MWh)		4.12	4.22	4.33	4.43	4.54	4.66	4.77	4.89	5.02	5.14	5.27	5.96	7.63	8.42
Vble O&M Costs ($/MWh)		3.54	3.63	3.72	3.82	3.91	4.01	4.11	4.21	4.32	4.43	4.54	5.13	6.57	7.25
Fixed O&M Costs ($/kW/year)		10.97	11.24	11.52	11.81	12.10	12.41	12.72	13.03	13.36	13.69	14.04	15.88	20.33	22.44
Fuel Costs ($mm)		51.46	52.46	63.15	65.51	71.19	74.92	82.24	71.11	87.69	92.11	93.50	105.79	135.42	149.48
Variable O&M Costs ($mm)		8.51	8.64	10.36	10.70	11.58	12.14	13.27	11.43	14.04	14.69	14.86	16.81	21.52	23.75
Fixed O&M Costs ($mm)		5.61	5.75	5.90	6.05	6.20	6.35	6.51	6.67	6.84	7.01	7.19	8.13	10.41	11.49
Decommissioning															70.85
Total Operating Costs ($mm)		***65.58***	***66.85***	***79.41***	***82.26***	***88.97***	***93.42***	***102.02***	***89.22***	***108.58***	***113.81***	***115.55***	***130.73***	***167.35***	***255.57***
Depreciation - Original ($mm)		25.33	23.43	21.68	20.05	18.55	17.16	15.87	14.68	14.48	14.48	14.48	14.48	-	-
Depreciation - Incremental ($mm)															
Interest ($mm)		10.43	10.08	9.74	9.39	9.04	8.69	8.34	8.00	7.65	7.30	6.95	5.22	1.74	0.35
Income Taxes ($mm)		(3.12)	(1.38)	0.98	2.87	5.05	7.14	9.66	10.16	13.55	15.56	17.25	22.85	38.99	14.29
Net Income		(4.40)	(1.95)	1.38	4.04	7.13	10.07	13.62	14.32	19.11	21.94	24.32	32.22	54.98	20.15
Capital Expenditures	(337.78)	-	-	-	-	-	-	-	-	-	-	-	-		
EOY Book Value	337.78	312.44	289.01	267.33	247.28	228.74	211.58	195.71	181.04	166.55	152.07	137.59	65.17	(0.00)	(0.00)
EOY Debt	130.38	126.04	121.69	117.34	113.00	108.65	104.31	99.96	95.61	91.27	86.92	82.58	60.84	17.38	0.00
Working Capital		4.69	4.85	5.66	5.93	6.44	6.82	7.48	6.82	8.17	8.65	8.93	10.27	13.15	14.52
Cash Flow															
Net Income		(4.40)	(1.95)	1.38	4.04	7.13	10.07	13.62	14.32	19.11	21.94	24.32	32.22	54.98	20.15
Depreciation		25.33	23.43	21.68	20.05	18.55	17.16	15.87	14.68	14.48	14.48	14.48	14.48	-	-
Capital Expenditures	(337.78)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt Cash Flow	130.38	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)	(4.35)
Working Capital		(4.69)	(0.16)	(0.81)	(0.27)	(0.51)	(0.39)	(0.65)	0.66	(1.35)	(0.49)	(0.27)	(0.25)	10.79	11.92
Net Cash Flow	(207.40)	11.90	16.97	17.90	19.47	20.82	22.49	24.49	25.31	27.89	31.59	34.18	42.10	61.42	27.72
Internal Rate of Return	12.5%														
2004 NPV @ 12.5%	($0.03)														

Note: Some columns are hidden for reporting purposes.

EXHIBIT RDK-S6

PP&L's Response to OCA Interrogatories, Set III, Nos. 49 and 74

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

Docket No. R-00973954

Q.49. What is the capacity price level required to install the lowest-cost new capacity additions, as cited on page 10, line 11 of Dr. Jones' testimony? What specific generating unit(s) and technologies define the least-cost capacity additions? Please provide all workpapers supporting the derivation of each component of non-fuel costs for the least-cost capacity addition, assuming an online date of January 1, 2000. These components should include but not be limited to: interest, taxes, O&M costs, A&G, and return on equity.

A.49. Capacity additions within PJM were based on the installation of natural gas-fired combustion turbine and natural gas-fired combined cycle units. These types of generating units are representative of the most modern, efficient, and low-cost generation capacity available for operation which many electric service providers are installing to meet supply needs. The approach used to install the new types of capacity additions was based on maintaining a minimum capacity reserve level of 18 percent in the PJM power pool. The modeling of these units within EGEAS was based on maintaining appropriate capacity reserves in the development of forecasted marginal energy prices, not for capacity cost determination.

As such, the operational features of the generation units are as follows:

a) Combustion turbine: 118 MW capacity rating, 10,200 BTU/kWh heat rate, 92% availability, base fuel price (natural gas) of 2.25 \$/MBTU, base variable O&M of 3.1 \$/MWH.

b) Combined Cycle units: 410 MW capacity rating; 7,000 BTU/KWH heat rate; 92% availability; base fuel price (natural gas) of 2.25 \$/MBTU; base variable O&M of 3.1\$/MWH.

Pennsylvania Power & Light Company
Response to Interrogatories
of the Office of Consumer Advocate, Set III
Dated April 18, 1997
Docket No. R-00973954
(Corrected Response - July 25, 1997)

Q.74. Please provide Dr. Jones' expectation of the annual cost of power from peaking and combined cycle units (page 25, line 13), and provide the associated workpapers. Please be sure to include:

a) The derivation of the annualized capacity price and estimated total cost of power (including capital and operating costs) for each option.
b) An explanation of the combustion turbine plant and combined cycle plants being represented, in terms of their assumed size, site, major components, and other distinguishing characteristics.
c) To the extent not provided in part (a), please provide the information source for each component (i.e., turbine/generator set, land, etc.) of the assumed capital cost for each unit.
d) The type of fuel supply arrangement assumed for each option, any why each is appropriate. In particular, please explain the "firmness" of the gas supply arrangements for each, and the path(s) by which such units would receive fuel.

A.74. a)

	Combined Cycle (CC)	Combustion Turbine (CT)
Capital costs	595 $/kW	338 $/kW
Cost of capital	8.91%	8.91%
Fixed O&M costs	9.00 $/kW/year	5.28 $/kW/year
Variable O&M costs	2.16 $/MWH	3.1 $/MWH

b) Combustion turbine (CT) and combined cycle (CC) plant additions were identified for installation in PJM for the appropriate forecast years to maintain an 18 percent capacity reserve margin in the PJM Power Pool. Each unit is dispatchable. The CT additions are rated at 118 MW and natural gas-fired based on firm gas prices (escalated to the appropriate year of installation/operation). The forced outage rate is 5.80 percent and CT full load heat rates are 10200 BTU/kWh. The CC additions are rated at 410 MW and are natural gas-fired. Forced outage rates and full load heat rates are 5.87 percent and 7000

BTU/kWh, respectively.

c) Dr. Jones asked PP&L personnel to evaluate recent vendor marketing/engineering data regarding the estimated unit capital cost and heat rate information for new combustion turbine (CT) and combined cycle (CC) units. Heat rates of 10,200 BTU/KWh and 7000 BTU/KWh were selected from a range of data that included substantially more efficient estimates for these units. For example, heat rates of 6700 BTU/KWh and less are claimed for some CC units. A similar survey of the cost/technical data for CTs and CCs was used to derive the capital cost estimates.

d) It is assumed that new combined-cycle generation capacity will be fueled by natural gas. Variable terms and conditions for the fuel supply contracts for these facilities were not explicitly modeled in the analysis.

EXHIBIT RDK-S7

PP&L's Response to Environmentalists' Interrogatory, Set 4, No. 207

Pennsylvania Power & Light Company
Response to Interrogatories
of the Environmentalists, Set 4
Dated June 9, 1997

Docket No. R-00973954

Q.207. Please specify the amount of new capacity added in each year of the study period. As to each generating unit added, please indicate the fuel type, capacity fixed and variable O&M costs, capacity factors, and emissions profile.

A.207. See the responses to Questions 49 and 88 of the Office of the Consumer Advocate, Set III, Dated April 17, 1997. These responses provide the fuel type of each generating unit added, and the amount of new capacity added during the study period.

See the responses to Questions 14 and 15 of the PP&L Industrial Customer Alliance, Set VIII, Dated June 5, 1997. These responses provide the capacity, and fixed and variable O&M costs for the study period.

Capacity factors for future capacity additions are provided in Attachment 1.

PP&L's market analysis considered the cost of SO_2 emissions only. The new capacity additions modeled would be fueled with natural gas which would produce no or negligible SO_2 emissions. Consequently, PP&L does not have "emissions" profiles" for these units.

ATTACHMENT 1

Capacity Factor data for future combined cycle and combustion turbine capacity additions
Range of capacity factors for all CTs and CCs in-service in any year

Year	combustion turbine capacity factors %	combined cycle capacity factors %
1997	--	--
1998	--	--
1999	7-8	--
2000	5-10	--
2001	8-14	--
2002	6-12	29
2003	6-13	33-52
2004	5-15	49-53
2005	5-17	52-55
2006	4-16	50-56
2007	5-28	58-66
2008	4-23	58-67
2009	4-30	61-71
2010	4-34	62-73
2011	4-37	66-75
2012	3-41	67-77
2013	3-43	42-79
2014	3-39	66-79
2015	3-41	66-82
2016	3-41	63-83

EXHIBIT RDK-S8

PP&L's Response to OSBA Interrogatory, Set I, No. 2

**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.2. Please define "non-bypassable" as specified at page 10 line 2 and page 18, line 1 of your testimony.

a. Should such a charge apply to self-generators not interconnected with the grid?

b. If the answer to part (a) is affirmative, please explain how such a charge can be collected.

c. If the answer to part (a) is negative, will this "non-bypassable" charge create inefficient incentives for customers to leave the grid?

d. Please explain why the non-bypassable charge should apply only to retail customers as indicated at page 18.

A.2. "Non-bypassable" refers to an access charge that all customers who use transmission and distribution services cannot avoid paying regardless of which energy supplier they are using.

a. As provided for in the Electricity Generation Customer Choice and Competition Act, a charge should be applied to any customer who is a self-generator and is interconnected with the utility's system.

b. Not applicable.

c. If a non-bypassable charge is not applied to customers that are not interconnected with the utility's system, there will be an incentive, although it may not be significant, for some customers to disconnect from the system to avoid paying this charge. To the extent that but for this non-bypassable charge the customer would not have disconnected from the system, this charge could be inefficient. Given that the non-bypassable charge will not increase rates because of the rate cap, any customers that would disconnect from the system are likely to have already done so.

d. In order to make the charge non-bypassable, it should be applied at the "end-of-the-wires," otherwise a retail customer could switch to another wholesale supplier, e.g., an out-of-state supplier, and avoid paying the access charge.