Paul E. Russell
Associate General Counsel
Tel. 610.774-4254 Fax 610.774.6726
E-mail: perussell@papl.com

PP&L, Inc.
Two North Ninth Street
Allentown, PA 18101-1179
Tel. 610.774.5151
http://www.papl.com/

ORIGINAL

ppl

February 12, 1998

DOCUMENT FOLDER

KJR

RECEIVED
98 FEB 12 PM 4:01
PA.P.U.C.
PROTHONOTARY'S OFFICE

VIA HAND DELIVERY
Mr. James McNulty, Prothonotary
Pennsylvania Public Utility Commission
North Office Building
North Street and Commonwealth Avenue
Harrisburg, PA 17105-3265

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

Dear Mr. McNulty:

Enclosed for filing in the above-captioned proceeding are an original and nine (9) copies of the Initial Post-Hearing Brief of PP&L, Inc.

This filing consists of two volumes. The first volume contains the Company's Brief and associated tables. The second volume contains proposed findings of fact and conclusions of law, and a duplicate set of the tables.

As indicated on the attached Certificate of Service, I have served copies of the enclosed Brief on all active parties in this proceeding.

If you have any questions regarding this filing, please call.

Very truly yours,

Paul E. Russell

Paul E. Russell
Associate General Counsel

Enclosures

cc: Certificate of Service

ORIGINAL

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF
PENNSYLVANIA POWER & LIGHT COMPANY
FOR APPROVAL OF RESTRUCTURING PLAN
UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

Docket No. R-00973954

INITIAL POST-HEARING BRIEF

ON BEHALF OF PP&L, INC.

TO ADMINISTRATIVE LAW JUDGE GEORGE M. KASHI

Paul E. Russell
PP&L, Inc.
Two North Ninth Street
Allentown, PA 18101

Donald A. Kaplan
Lisa M. Helpert
Preston Gates Ellis & Rouvelas Meeds LLP
1735 New York Avenue, N.W., Suite 500
Washington, D.C. 20008-4759

Attorneys for PP&L, Inc.

Dated: February 12, 1998

TABLE OF CONTENTS

TABLE OF AUTHORITIES

CASES

STATUTES

REGULATIONS

INTRODUCTION

A. Statement of Position

On December 3, 1996, the Pennsylvania General Assembly enacted the Electricity Generation Customer Choice and Competition Act (the "Act"). This landmark legislation is a bold initiative to establish competition and customer choice in the retail electric generation market. In accordance with the Act and the schedule established by the Pennsylvania Public Utility Commission ("PUC" or the "Commission"), PP&L, Inc. ("PP&L or the "Company") filed its Restructuring Plan on April 1, 1997, to introduce retail competition for the sale of electricity in its service territory. After extensive discovery, testimony and hearings, PP&L's plan is now ready for decision.

This case presents the PUC with its first opportunity to address retail competition issues for a low-price, highly efficient provider of electric service. PP&L has maintained low prices by delaying retail base rate increase requests for as long as possible and keeping costs down. At the same time, the Company has continued to make substantial capital investments to ensure high quality service to customers and efficient low-cost generation of electricity. The resulting cost savings have been flowed through to customers in the form of lower energy prices making electricity more affordable and promoting economic development in PP&L's service area.

The Commission's decision in this case will directly and dramatically affect PP&L's financial integrity and its ability to provide safe and reliable service and, to a very large extent, will determine the success of the Pennsylvania initiative to create a robust competitive retail market for electric generation.

The record unequivocally demonstrates that PP&L has been and continues to be an active proponent of retail electric competition. To achieve this goal, however, requires a fair and orderly transition from regulation to competition. Without such a transition, efficient and effective competition will not develop; the electric industry will be financially crippled; reliable service will be jeopardized; and the Pennsylvania competition initiative will wither.

In PP&L's view, the Act establishes four critical components for a fair and balanced transition to competition:

1. The establishment of reasonable terms and conditions for open access retail competition;

2. The calculation and recovery of reasonable stranded costs;

3. The establishment of unbundled rates for the generation, transmission and distribution of electricity; and

4. The provision of continued customer protections, particularly the continuation of safe and reliable service and programs for the assistance of low-income customers.

PP&L's position on each of these four components is summarized briefly here and addressed at length in the body of this Brief. However, two initial comments are in order. First, many of the potentially controversial issues regarding retail competition have been resolved by the Act, which provides a blueprint for restructuring electric utilities on a case-by-case basis.

Second, and of equal importance, in preparing its filing, PP&L carefully sought a balanced approach that treats all interests fairly; is consistent with the letter and intent of the Act; and properly reflects PP&L's position as a low-price provider of electric service. To a very large extent, this approach was successful. Although many parties participated in the case and filed extensive discovery and testimony, the differences among most of the parties on most issues were remarkably small, particularly when compared to other restructuring proceedings. The most notable exception was the calculation of stranded costs, where the parties are, unfortunately, far apart. As to this critically important issue, PP&L believes that its stranded cost claim is fully supported by the Act, established regulatory policy and overwhelming record evidence and is fair to its customers, investors and new competitors.

*1. **Rules for Retail Competition***. In accordance with the Act and PUC regulations, PP&L's Restructuring Plan sets out the terms and conditions for retail competition, including a proposal to provide comparable and non-discriminatory access to the Company's transmission and distribution system, procedures and rules under which the Company will participate as a supplier of electricity, and an extensive proposal for customer education. Most of the dispute on these issues focused on the Code of Conduct under which PP&L, through its Generation Supply Group, will participate as a supplier of electricity. In resolving these issues, it is important to remember that the purpose of a competitive code of conduct is to protect competition, not competitors. Opposing parties propose a "laundry list" of rules and restrictions which, if adopted, would severely handicap PP&L's ability to compete fairly and effectively. Viewed objectively, these proposals provide competitors with artificial and unnecessary protections from competition. These rules, if adopted, would interfere with customer choice and prevent the benefits of competition from reaching the proper and intended beneficiaries – consumers.

One issue of particular concern is the proposal by Enron that PP&L be prohibited from using its corporate name as a competitive supplier of electricity. This prohibition is inappropriate and unnecessary. PP&L's potential competitors, including Enron, other electric and telephone utilities and large retailing companies, have a strong market presence and have more than adequate resources to overcome the single brand name of PP&L. Any concerns about potential customer confusion are fully covered by PP&L's commitment to clearly and explicitly distinguish delivery service and generation supply service as separate operations. Indeed, customer confusion and deception would most likely occur if PP&L were prohibited from doing business under its own name. PP&L's good reputation and name are valuable corporate assets paid for by shareholders over the past 75 years. It would be fundamentally unfair, inappropriate and unlawful to deprive PP&L of the use of (or to require it to pay to use) its own corporate name.

2. ***Stranded Cost Recovery.*** The most contentious issue in this case is the calculation and recovery of stranded costs. At the outset, it is important to recognize that all of the stranded costs identified by PP&L in this case are reflected in PP&L's current retail rates. The origins and nature of these costs fully support recovery in current rates and in a future Competitive Transmission Charge ("CTC"). Purchases from Non-Utility Generators ("NUG"s) were mandated by federal and state law and regulations. Deferred taxes arose from PUC ratemaking decisions under which accelerated tax benefits were flowed through to customers immediately, with resultant higher taxes to be paid by the utility in the future. Investments in generating plants were necessary to maintain reliable service to customers, and those investments were found to be prudent by the Commission. Environmental costs were incurred to help protect land, air and water in the Commonwealth. The Company prudently incurred these costs for the reasons summarized above, not as a result of any mismanagement or bad decisions.

The basic legal and economic support for stranded cost recovery is set forth in Section II, *infra*. The case for just and reasonable stranded cost recovery is clear not only from the Act itself and 100 years of regulatory history, but also from common sense. In reviewing the myriad of issues and sub-issues relating to stranded cost recovery, PP&L urges the Commission to consider three important principles which are essential to the determination of a reasonable stranded cost allowance and continued safe and reliable service by a financially viable utility.

First, any fair consideration of PP&L's stranded costs must begin with the level of its present rates. PP&L's rates today are essentially the same as they were twelve years ago in 1986, and are over 25% lower in real terms when adjusted for inflation. PP&L's rates are well below the Pennsylvania average and over 30% less than the highest cost Pennsylvania supplier, PECO Energy Company. Indeed, PP&L's rates today are just marginally above the national average, and PP&L's current residential rates are *below* the national average.

These low rates are the direct result of PP&L's aggressive and extensive mitigation efforts, including refinancing high cost capital (approximately $100 million in savings); O&M cost reductions (15% real reduction in the last 10 years); reductions in planned capital expenditures ($671 million); employee reductions (approximately 25% since 1985); inventory-related reductions (over $125 million); excellent nuclear operations; gas/oil dual fuel capability at the Company's Martins Creek plant; buy-out of NUG contracts and extensive economic development initiatives. One of the goals of the Act is to spur high cost utilities to cut costs and reduce rates. PP&L, as demonstrated by its past efforts, has been actively pursuing this goal for years and has already passed on the savings to customers.[1] In accordance with requirements of the Act, these past efforts must be considered by the PUC in determining the reasonableness of the Company's stranded cost claim.

Second, PP&L's proposed stranded cost recovery of $4 billion must be viewed in light of its total stranded costs. PP&L's gross stranded costs are approximately $5.5 billion. PP&L has projected major future mitigation efforts, including projected reduction in capital additions, O&M expense and workforce reductions, NUG buyouts and a depreciation reserve transfer, which reduced the Company's stranded costs by over $1 billion, to $4.5 billion.[2] Moreover, because of PP&L's already low rates, the rate caps in the Act will limit PP&L's stranded cost recovery to $4.0 billion.[3] Thus, even if PP&L's claim were approved in full, PP&L would collect only slightly more than 70% of its total stranded costs.

---

1 PP&L had the most recent base rate case of any major electric utility in the state (1995). Savings from past mitigation, therefore, have already been fully passed through to customers, which is not the case for other utilities that have not had recent base rate cases.

2 With the exception of the reserve transfer, PP&L bears the risk of achieving all of these savings.

3 The Company also must pay income taxes on this revenue and will actually recover only $2.25 billion in stranded costs on an after-tax basis.

Third, the entire discussion of stranded costs must be viewed in the broader context of an emerging competitive market. So called "stranded costs" reflect only a relatively small portion of the Company's total projected costs of operation. As PP&L moves into the competitive market, it must recover its total costs of operation from both the CTC and market revenues. In this case, PP&L has projected a significant and constant upward trend in market prices, starting at $22/Mwh in 1999 and increasing to $37/Mwh by 2016. These increases may or may not actually occur – indeed, if anything, history predicts they will not. Approval of PP&L's stranded cost claim thus provides it no assurance or "guarantee" that it will be able to recover its actual costs of operation.

Viewed in this context, it is apparent that PP&L's stranded cost claim is reasonable and should be approved without substantial controversy. Several opposing parties, however, have taken a different course and have recommended a virtual total disallowance of PP&L's claim. OCA has proposed stranded cost recovery of $1.1 billion; PPLICA only $661 million. These proposals have no factual basis, would produce devastating financial results to PP&L, are totally unfair, and must be rejected.

Some proposals in this case, if adopted by the Commission, would result in a negative return on equity for PP&L and would jeopardize electric service in PP&L's service territory. The PUC found that PP&L's existing rates were just and reasonable in 1995. There is no rational basis to conclude that PP&L's rates can or should be reduced substantially in 1999, or that PP&L can operate safely and reliably with no return on common equity.

The OCA, and others, will likely cite the PUC's recent Order in PECO Energy's restructuring proceeding to support their position on several issues. The Administrative Law Judge ("ALJ") and the PUC should view these references with caution. Both the Act and common sense indicate that each utility's restructuring proceeding must be decided on its own merits. Any effort to select isolated findings from one utility's restructuring plan decision and apply it to another is fraught with peril. PECO is the highest cost supplier in the state and one of the highest in the nation. Moreover, PECO's rates were last set in 1991 and do not reflect savings achieved over the last seven years. Thus, rate "reductions" that may appear reasonable for PECO would be devastating for utilities such as PP&L who already have low rates and have had recent rate cases which flowed through cost savings to customers.

Market price and market revenue analogies should be viewed with particular skepticism. While the OCA market price may produce a reasonable result for PECO, it will produce an unreasonable and devastating result for PP&L. An overall market price projection is based on a myriad of assumptions, many of which were never contested in the PECO case because they have little or no impact on PECO's operation. These same assumptions, however, dramatically affect PP&L's stranded costs and were aggressively challenged in this case.[4] Fundamental fairness and due process require that these issues be fully dealt with on this record.

Finally, the result in the PECO case fully supports rejection of OCA's position. At $1.1 billion in stranded costs, the OCA recommends that PP&L recover less than 25% of its stranded cost claim. Yet, the PUC awarded PECO 73% of its claim and 90% of the amount PECO accepted in its Partial Settlement. PP&L, given its aggressive past and future mitigation and resulting low rates, should receive a much higher percentage of its claim. Approval of PP&L's claim will allow it an opportunity to recover 70% of its gross stranded costs and approximately 90% of its net stranded costs. This is clearly reasonable and conservative for a low price,

---

[4] For example, OCA projects rapidly escalating gas prices but relatively flat coal prices. Over time, this produces a very large (and historically unprecedented) spread between gas and coal prices. This spread has very little effect on the overall market price (which is largely driven by gas prices) and had little effect on PECO's stranded cost (because PECO has very few coal units). As a result, this issue was not litigated in the PECO restructuring case. However, this issue dramatically affects PP&L (because it has many coal plants), causing OCA to recommend a $230 million reduction in PP&L's stranded costs on this issue alone. Other equally damaging (and unsupportable) market price adjustments are discussed in Section IV, *infra.*

efficient provider of electric service. Indeed, the Act specifically directs the Commission to consider past mitigation and low rates in providing for stranded cost recovery.

3. Unbundled Rates and Rate Design. In accordance with the Act, the Company "unbundled" its rates into generation, transmission and distribution functional categories, including a CTC to recover stranded costs. PP&L proposed a rate design to facilitate full and fair competition, send appropriate price signals to customers, comply with the rate caps contained in the Act, and implement significant rate reductions for incremental usage of electricity. To prevent cost shifting among and within customer classes, the Company unbundled its existing rates based on the cost allocation study approved by the PUC in the Company's 1995 base rate case. The Company also proposed a revenue reconciliation mechanism to prevent over/undercollection of allowed stranded costs and a surcharge to recover nuclear decommissioning costs so as to avoid a burdensome pre-funding requirement by the Nuclear Regulatory Commission.

Although there was opposition on certain details of these proposals, the most serious dispute arose over the Company's proposed Customized Rate Design ("CRD"). Under this proposal, PP&L proposed to collect one-half of the CTC through a fixed charge and one-half through a variable (per kWh) charge. The CRD was revised to make it optional for all customers. The Company believes this revised proposal should be approved because it provides many important benefits. It moves toward marginal cost pricing, which sends more efficient price signals to customers, and is more consistent with a competitive market. The revised proposal also offers customers a very significant rate reduction for incremental usage, which should spur development of a competitive market, provide for a significant rate reductions for customers and promote economic development.

4. Additional Protection for Low-Income Customers As explained below, PP&L's filing, consistent with the Act, provides for several important customer protections, including significant rate caps extending for up to nine years from the effective date of the Act, the availability of PP&L as the "supplier of last resort" and a broad commitment to continued safe and reliable service. In addition, and in accordance with the spirit of the Act, PP&L is proposing to expand its programs for low-income customers who have trouble paying their bills. PP&L, for many years, has been a leader in providing support and assistance to low-income customers. PP&L proposes to extend that commitment by more than doubling its financial support for its "On-Track Program", an increase of $7 million over the next five years, to be recovered through a universal service charge, as provided by the Act.

Certain parties proposed massive expansions of PP&L's low-income programs. While PP&L sympathizes with and supports the motivation for these proposals, these proposals simply are not practical at this time, given the rate caps in the Act. Moreover, these proposals would extend massive discounts to customers who currently are paying their bills in full and on time. This is not fair or appropriate, particularly because these discounts would be paid for by other customers and would cause cost-shifting in violation of the Act.

B. Procedural History

In accordance with the PUC Order entered January 24, 1997, at Docket No. M-00960890.F05, PP&L filed its Restructuring Plan on April 1, 1997. In its Restructuring Plan filing, as revised during this proceeding, PP&L: (a) proposed the unbundling of its rates, establishment of CTCs and specific tariff provisions to ensure customers direct access to all licensed Electric Generation Suppliers ("EGSs"); (b) projected its transition costs under the Act at $ 4.5 billion; (c) proposed a plan to meet its universal service obligations, including a mechanism to recover the costs of those obligations; (d) described implementation of a consumer education program; and (e) proposed procedures for implementing PP&L's responsibilities as provider of last resort under 66 Pa. C.S. § 2807(e)(3).

Copies of the filing were served on all active participants in PP&L's last general base rate investigation at Docket No. R-00943271 and provided to any person who requested a copy. PP&L provided notice of its Restructuring Plan filing to all customers by bill insert beginning with the April 1997 billing cycle. The Company further provided a one-page notice of its filing to all individuals on the Executive Director's Stakeholder list. In addition, notice of the filing was published in newspapers of general circulation throughout PP&L's service territory.

PP&L's Restructuring Plan filing was assigned to ALJ George M. Kashi, and a first prehearing conference was convened in Harrisburg on April 18, 1997. Second and third prehearing conferences were held in Harrisburg on May 16, 1997 and July 15, 1997, respectively. Thirty nine parties were permitted to intervene in this proceeding. Of that group, seventeen intervenors have maintained active party status. In addition, Formal Complaints against the Company's Restructuring Plan were filed by the OCA, PPLICA and the Environmentalists. Table A contains a list of the parties.

PP&L submitted with its Restructuring Plan filing extensive supporting information, including the direct testimony and supporting exhibits of seventeen witnesses and responses to the Commission's filing requirements. Supplementing that information, PP&L responded to nearly 1000 interrogatories and data requests and has exchanged a significant amount of information with other parties on an informal basis. In addition, an informal technical conference was held in Harrisburg on May 2, 1997, at which PP&L made available several of its witnesses to answer questions and further explain their testimony.

On July 2, 1997, the intervenors submitted extensive direct testimony addressing almost every aspect of PP&L's Restructuring Plan. On August 5, 1997, PP&L responded to the intervenors' direct testimony by filing rebuttal testimony and exhibits sponsored by twenty witnesses. A number of the intervenors submitted surrebuttal statements on August 15, 1997.

Evidentiary hearings were held in Harrisburg on August 18-22 and August 25-29, 1997 and on September 9, 1997. During those hearings 284 exhibits and the testimony of 57 witnesses were admitted into evidence. The transcribed record of the evidentiary hearing consists of 2,337 pages. The evidentiary record was closed on September 9, 1997.

Thirteen public input hearings were held during the weeks of May 30, 1997 and September 2, 1997. Public input hearings were held in Allentown (June 2), Bethlehem (June 2 and September 3), Harrisburg (May 30 and September 3), Hazelton (June 4), Lancaster (May 30 and September 2), Pottsville (June 4), Scranton (June 3 and September 4), Williamsport (June 5), and Wilkes-Barre (June 3). A total of 75 persons testified at the public input hearings.

Following the hearings, at the urging of the presiding ALJ, the parties entered into settlement discussions. Tr. 1593 (8/26/97). To accommodate those discussions and other events relating to the restructuring of the industry, the post-hearing briefing and decision schedule was extended several times. Orders extending the briefing schedule and the date for Commission decision in the case were issued on September 12, 1997, October 17, 1997, November 25, 1997 and December 24, 1997.

The remainder of this Brief follows the "commonality of issues identification" attached to the Briefing Order issued by the ALJ on September 23, 1997. Although some of the issues raised in the proceeding or that have arisen as a result of the decision in the PECO Restructuring proceeding did not readily fit into the specific categories of that outline, particularly those related to the two methodologies of calculating stranded costs, PP&L has attempted to address each of the issues in its Restructuring Plan filing under an existing heading with appropriate explanation of how other topics may be affected. In addition, PP&L is submitting Tables, attached to this Brief, and Findings of Fact and Conclusions of Law, bound separately, pursuant to the September 23, 1997 Briefing Order.

I. CONTEXT OF RESTRUCTURING

This proceeding raises issues of extreme significance not only to customers and investors of utilities, as ratepayers and investors, but as citizens of the Commonwealth. The decisions made here will affect the manner in which a service essential to modern life, electricity, will be provided within a significant portion of the Commonwealth for many years into the future. In reaching these decisions, the Commission must not only balance the interests of customers and investors, but must also balance the short and long term interests of current and future customers and investors.

Fortunately, the Commission is guided in this proceeding by the General Assembly as it has spoken through the Act. As will be explained in this Brief, the Act embodies a balance between interests of customers and investors that mirrors the balance drawn by many years of utility law and regulation. Therefore, it is important for the Commission to consider and interpret the Act in the context of the economic and legal background which led to its adoption.

A. Economic and Competitive Background

For most of this century, the provision of electric service in Pennsylvania has been extensively regulated by the PUC because the provision of that service has been considered a natural monopoly. A natural monopoly is a business which, by reasons of scale or scope, is provided more efficiently by one company than by competing companies.

There can be no dispute that electric utilities have been viewed as natural monopolies in Pennsylvania since the adoption of the Public Service Company Law of July 26, 1913, P.L. 1374 (repealed), as amended by section 4 of the Act of June 3, 1933, P.L. 1526, 66 P.S. §201-2 (repealed). The Public Service Law and its successors recognize that in exchange for a monopoly to provide service in an exclusive service territory, public utilities were both exempted from competition and obligated to provide service within that service territory. Regulation of rates and service was determined to be necessary to replace the lack of competition.

While there are many aspects to this regulation, an overriding theme has been described as the regulatory bargain or regulatory compact. The regulatory compact was described by Professor Kalt[5], as follows:

> In the pre-reform regulatory setting, utilities and the investors who provide utility capital accepted an obligation to serve all electric demand in their service territory. Pursuant to this obligation to serve, utilities accepted the obligation to incur the costs of sufficient generation and related capacity to ensure that expected demand could be satisfied, with these investment plans being subject to review and oversight by regulators and with their decisions reflected in just and reasonable rates regulators have allowed utilities to charge their customers. Investors in utility companies agreed to provide the capital necessary to make these investments under regulatory rules that subjected cost recovery to cost-of-service regulatory principles rather than market forces. PP&L St. 1, pp. 11-12.

Pursuant to this system of regulation, PP&L invested billions of dollars to construct generating stations to meet the reasonably projected needs of customers in its service territory. These investments have been reviewed by the Commission and have been determined to be prudent expenditures. Accordingly, under a continuation of regulated monopoly service, PP&L and its investors would have recovered both a return of, and a reasonable return on, such investments to provide service to customers. See 66 Pa.C.S. § 1301.

---

5 Professor Kalt is the Ford Foundation Professor of International Political Economy and the Chairman of the Economics and Quantitative methods section at the John F. Kennedy School of Government, Harvard University. He specializes in natural resources and energy policy and has published widely on matters relating to the regulation of natural gas, electricity, oil and coal markets. He has testified in numerous administrative, judicial and congressional proceedings concerning performance of the nation's energy markets.

As explained by Professor Alfred Kahn,[6] the regulated monopoly system has served customers well for a long period of time. *See* PP&L St. 18-R, p. 21. However, changes in economic circumstances prompted a re-examination of this regulatory system:

> What has changed since then? Manifestly, the relationship between price and marginal cost, both short- and long-run: what other answer would you expect from an academic economist?
>
> The reasons for that dramatic change are familiar: First, the entry into service of long-lead-time base-load plants, constructed over a period of double-digit inflation of interest rates and construction costs and in anticipation of a continued expansion of demand at 6 to 7 percent annual rates. These developments and the abrupt deceleration of demand left utilities, particularly on the East and West coasts, with average generating costs in the range of perhaps 6 to 10 cents a kwh and, because of their excess capacity, short-run marginal costs of 1 to 2 cents. Second the collapse of fossil fuel prices in the middle 1980s, in combination with, third, the development of combined cycle gas turbine technology, which have made it possible to build 100-megawatt or smaller new plants with average costs on the order of 4 cents a kwh.
>
> Fourth, the nuclear fiasco. And, fifth, PURPA, with its legacy of multi-billion dollar contractual obligations of the electric companies to buy independently generated power at rates set at avoided costs estimated by regulators on the basis (among other consideration) of expectations that the price of oil would by now be nearing $100 a barrel.
>
> All these developments have combined to produce regulated rates in some regions of the country, far above both short- and long-run marginal costs. And that in turn has created irresistible temptations for sellers - including utility companies, *outside* their own

---

6 Professor Kahn has been Chairman of the New York State Public Service Commission and the U.S. Civil Aeronautics Board. He is the author of the two-volume, *The Economics of Regulation*, reprinted, in 1988 by MIT Press and has written and testified extensively in the area of direct economic regulation and particularly of the public utilities.

> franchise territories - to offer eager buyers an escape from those inflated rates. PP&L St. 18-R, pp. 21-22.

This significant metamorphosis in the economics of producing electric power led the General Assembly to conclude that generation of electricity can be provided more efficiently (at lower costs) under a competitive system.

B. Legal and Legislative Background

In adopting the Act, the General Assembly observed that "[o]ver the past 20 years, the Federal Government and State government have introduced competition in several industries that previously had been regulated as natural monopolies." 66 Pa.C.S. § 2802(1). The electric power industry did not escape this trend. In 1992, Congress passed the Energy Policy Act which specifically empowered the Federal Energy Regulatory Commission ("FERC") to order public and privately owned utilities to grant access to their transmission systems for qualified entities engaging in wholesale power transactions. 16 U.S.C. §§ 824(j),(k). The FERC dramatically expanded the availability of transmission in 1996 by issuing Order No. 888, requiring public utilities to unbundle wholesale contracts and offer open access non-discriminatory transmission service to all eligible customers — including retail customers in states implementing retail competition — while providing for the recovery of stranded costs incurred as a result of such open access. *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 78 FERC ¶ 61,220 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (1997), 81 FERC ¶ 61,248 (1997) ("Order No. 888").

C. The Electricity Generation Customer Choice and Competition Act

The Act contains declarations of policy which set forth the reasons why the General Assembly directed the restructuring of the electric industry in Pennsylvania. 66 Pa.C.S. § 2802. The Act also contains specific standards for restructuring of the electric industry. 66 Pa.C.S. § 2804. These declarations and standards set the bounds within which the restructuring of the electric industry is to be conducted and within which the issues in this proceeding must be resolved.

1. Concerns Addressed by the Act

The purpose of the Act is to mandate competition and create a transition to a competitive market for the generation of electricity. 66 Pa.C.S. § 2802(12). Within this general purpose there are several other critical concerns expressed by the General Assembly which are relevant to this proceeding.[7] The most important of these concerns are summarized here and will be referenced as applicable to specific issues later in this Brief. First and foremost, the General Assembly recognized the need for a fair transition to a competitive retail electric generation market:

> In moving toward greater competition in the electricity generation market, the Commonwealth must resolve certain transitional issues in a manner that is fair to customers, electric utilities, investors, the employees of electric utilities, local communities, non utility generators of electricity and other affected parties. 66 Pa.C.S. § 2802(1).

The Act also recognizes that electric utilities and their investors have invested billions of dollars in generating facilities, that some of these costs may not be recovered under a competitive

---

[7] Provisions of the Act which are not directly relevant to this proceeding, such as licensing requirements for suppliers to protect reliability, are not summarized here.

system and that electric utilities should be permitted to recover such costs during the transition period to the extent possible within the rate cap.

> In establishing the standards for the transition to and creation of a competitive electric market, heretofore, public utilities generally have had an obligation to serve customers within their defined service territories; consistent with that obligation, have undertaken long-term investments in generation, transmission and distribution facilities in order to meet the needs of their customers; and have entered into long-term power supply agreements as required by Federal law. In many instances, these investments and agreements have created costs which may not be recoverable in a competitive market. The commission is empowered under this chapter to determine the level of transition or stranded costs for each electric utility and to provide a mechanism, the competitive transition charge, for recovery of an appropriate amount of such costs in accordance with the standards established in this chapter. 66 Pa.C.S. § 2802(15).

As explained in detail later in this Brief, these principles and standards must guide the ALJ and the Commission in resolving the issues in this proceeding.

Another significant concern of the General Assembly as expressed in the Act is the manner in which competition will be conducted. In this regard the Act provides that:

> This chapter requires electric utilities to unbundle their rates and services and to provide open access over their transmission and distribution systems to allow competitive suppliers to generate and sell electricity directly to consumers in this Commonwealth. *The generation of electricity will no longer be regulated as a public utility function except as otherwise provided for in this chapter.* Electric generation suppliers will be required to obtain licenses, demonstrate financial responsibility and comply with such other requirements concerning service as the commission deems necessary for the protection of the public. 66 Pa.C.S. § 2802(14) (emphasis added).

To implement this open access requirement, the Act sets forth certain standards to which the Commission must adhere:

> The commission may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure. 66 Pa.C.S. § 2804(5).
>
> Consistent with the provision of section 2806, the commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system. 66 Pa.C.S. § 2804(6).
>
> The commission shall require that restructuring of the electric utility industry be implemented in a manner that does not unreasonably discriminate against one customer class to the benefit of another. 66 Pa.C.S. § 2804(7).

These standards are clear. Utilities are not prohibited from continuing to provide, or compete for, electric generating customers either through affiliates or divisions but "rates and terms" of access to the transmission and distribution systems by other suppliers must be "comparable to the utility's own use." Accordingly, the implementation of such standards in a manner that provides open access to other suppliers without handicapping PP&L's efforts to sell electricity from its generating stations to retail customers is another critical issue in this proceeding.

The General Assembly also was concerned that Pennsylvania's consumers of electric power be prepared to take advantage of the benefits of competition. In addition to providing for a retail access pilot, 66 Pa.C.S. § 2806(G), the General Assembly obligated each electric distribution company to implement, in conjunction with the Commission, a consumer education program that "shall provide consumers with information necessary to help them make appropriate choices as to their electric service." *66 Pa.C.S. § 2807(d)(3).*

The final major concern expressed in the Act that is relevant to this proceeding concerns the protection of customers who do not or cannot obtain service from a competitive electric supplier. In this regard, the Act contains specific policy determinations requiring continuation of programs that currently assist low-income customers, 66 Pa.C.S. § 2802(10), and other public purpose programs. 66 Pa.C.S. § 2802(17). Finally, the Act also contains requirements applicable to electric companies that are intended to provide all customers with reliable transmission and distribution service and to provide all customers with a supplier of last resort. 66 Pa.C.S. § 2802(16).

These obligations are important safeguards for the transition to competitive generation service and continue the special obligations currently held by public utilities generally. These provisions require the Commission to resolve specific issues concerning universal service and supplier of last resort service. However, the special obligations of providing continued, regulated transmission and distribution service, as well as the requirement to provide supplier of last resort service, also must be considered as they relate to other issues in this proceeding. Specifically, the interests of ratepayers must always be balanced against the requirement that the Commission foster the development of a competitive supply market while maintaining the long-term viability of the electric distribution company so that it can continue to provide regulated transmission and distribution service throughout its service territory and provide supplier of last resort services in the future.

2. Post-Restructuring Electricity Market Under the Act

The Act envisions a transition from the provision of electric generation service by a single monopoly supplier to a system under which numerous suppliers compete to sell generation to customers. Open access transmission and distribution systems will provide non-discriminatory access to all qualified suppliers. The Act also recognizes that the generation currently owned by electric utilities is the backbone of electric service in Pennsylvania and is necessary for the continued service of customers in Pennsylvania. Accordingly, the Act specifically authorizes electric utilities to maintain these facilities and use them to provide competitive service as well as supplier of last resort service to customers.

The Act recognizes that the transition to competition will require recovery of generating costs that have become stranded as a result of that transition. The recovery of stranded costs is designed to enable electric utilities to participate on reasonable terms in a competitive market while maintaining a viable company to provide transmission and distribution services and supplier of last resort service. The Act also envisions a competitive market in which programs for low-income customers are maintained and the associated costs are recovered through a universal service fund.

Finally, the Act envisions the coordination of suppliers and the electric distribution company through an Independent System Operator ("ISO") in a manner that maintains the highly reliable service presently provided by PP&L and other electric utilities. 66 Pa.C.S. § 2802(19); 66 Pa.C.S. § 2804(1).

II. LEGAL AND POLICY FOUNDATIONS OF STRANDED COST RECOVERY

A. Legal Standards

1. Statutory Provisions

The Act addresses stranded costs in three different ways. First, the "Declaration of Policy," Section 2802(15), establishes the general need for and appropriateness of recovery by electric utility companies of their stranded costs.

Second, the Act provides a general definition of "stranded costs." Section 2803 defines "stranded costs" as:

> An electric utility's known and measurable net electric generation-related costs, determined on a net present value basis over the life of the asset or liability 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.

The definition also provides a list of categories of potentially stranded costs. Third, Section 2804(14) of the Act mandates an "orderly" transition to competition designed to "provide the investors in Pennsylvania electric utilities with a fair opportunity to fully recover the amount of transition or stranded costs that the commission determines to be just and reasonable."

These provisions mandate that the Commission allow recovery of an appropriate level of stranded costs. In adopting these provisions, the General Assembly has balanced the interests of electric utilities and ratepayers in a proper manner. The Act seeks to attain, on one hand, the benefits for customers of low-cost electric generation. On the other hand, the Act permits electric utilities to collect their prudently-incurred costs which would be recoverable under the prior system of regulation but which may not be recoverable under a competitive regime.[8] This recovery of prudently-incurred stranded costs is fully consistent with general principles applicable to regulated utilities.

---

[8] There is one exception to the principle that prudently-incurred stranded costs are recoverable. Recovery may be precluded by operation of the rate caps of Section 2804(4) of the Act. As explained below, PP&L will not be able to recover approximately $500 million of stranded costs as a result of the rate caps, and its low cost rates.

2. Regulatory Compact

There can be no doubt that the Commonwealth and its regulated utilities have operated for decades under a requirement of mutual obligations regardless of whether those obligations are referred to as a "regulatory compact," "regulatory bargain," "understanding," or something else. The essence of that mutuality of obligation was that utilities had a fair opportunity to recover their prudently-incurred investments in facilities used to meet their obligation to serve all customers. Professor Kalt described this obligation as follows:

> Despite semantic and legalistic arguments to the contrary, it has been recognized at the highest levels of economic and public policy-making that there exists a 'regulatory compact' that has historically governed the relationship between regulated utilities and the government; and that this compact appropriately requires that regulatory reform not take away the reasonable prospect for recovery of costs that utilities incurred pursuant to their obligations under the regulatory regime in place at the time of their key cost-creating decisions. In the pre-reform regulatory setting, utilities and the investors who provide utility capital accepted an obligation to serve all electric demand in their service territory. Pursuant to this obligation to serve, utilities accepted the obligation to incur the costs of sufficient generation and related capacity to ensure that expected demand could be satisfied, with these investment plans being subject to review and oversight by regulators and with their decisions reflected in the just and reasonable rates regulators have allowed utilities to charge their customers. Investors in utility companies agreed to provide the capital necessary to make these investments under regulatory rules that subjected cost recovery to cost-of-service regulatory principles rather than market forces. PP&L St. 1, pp. 11-12 (footnote omitted).

These conclusions were reinforced by the testimony of Professor Alfred Kahn, who stated:

> I emphatically assert that there has indeed been a general understanding, over many decades, under original cost or prudent investment regulation such as has been practiced in the great majority of our jurisdictions, that the utility companies, in exchange for thoroughgoing regulation and the undertaking of costly public service responsibilities, were entitled to a reasonable

opportunity to recover their prudently incurred costs . . . . PP&L St. 18-R, p. 10.

The General Assembly has expressly recognized the general principles of this bargain or understanding in the Declaration of Policy at Section 2802(15) of the Act. There, the General Assembly acknowledged the historic obligation of utilities to make substantial investments in facilities or contracts to provide safe and reliable service. The General Assembly also recognized its obligation to allow recovery of costs stranded by the change the electric generation portion of electric utilities' business from a regulated monopoly to an unregulated competitive service.

Contentions that these obligations do not exist deny the obvious. Clearly, utility investors relied on prior rules concerning the prudent investment standard and fair rates of return in forming their expectation concerning risks and returns. This conclusion is confirmed by the fact that the General Assembly believed it was necessary to adopt the Act in order to change the manner in which electric generation is regulated. Further, in the Act, the General Assembly mandated substantial proceedings, such as this one, in which a major issue is the amount of stranded costs to be recovered. PP&L St. 1-R, p. 57.[9]

---

9 The Act, in this respect, is consistent with prior law. The Commonwealth Court has ruled that denying the recovery of costs caused by a change in regulatory requirements would be fundamentally unfair under the Public Utility Code. In *Columbia Gas of Pa., Inc. v. Pa. P.U.C*, 149 Pa. Comwlth. 247, 613 A.2d 74, 80 (1992), the Commonwealth Court reversed the Commission's denial of recovery of costs of customer arrearages (uncollectible accounts) that were created by the Commission's requiring utilities to continue to serve non-paying customers.

3. Federal Constitutional Doctrines

The fundamental principles of the Commonwealth's obligations to its regulated utilities are consistent with federal constitutional "due process" principles applicable to takings of utility property. PP&L's stranded costs were incurred to meet its obligation to serve customers, but these costs may not be recoverable in the competitive market for electric generation which is being created by the Act. If the Act did not provide for recovery of stranded costs, or if the Act were applied in a manner that denied recovery of stranded costs, the change in regulatory policy would violate the Fifth and Fourteenth Amendments to the United States Constitution.

The United States Supreme Court has stated that fundamental changes in regulatory rules that prevent recovery of previously approved cost would violate the fundamental due process and "takings" clauses of the Fifth and Fourteenth Amendments to the United States Constitution:[10]

> The risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks. Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investment at others would raise serious constitutional questions. *Duquesne Light Co. v. Barasch,* 488 U.S. 299, 315 (1989).

See also United States v. Winstar Corp., __ U.S. ___, 116 S. Ct. 2432 (1996) (Uncompensated taking caused by changes in regulatory accounting rules that reduced the book value of assets that the savings and loan company had relied upon to meet capital reserve requirements). In the Act, the General Assembly avoided these potential constitutional issues by providing for

---

10 Such an improper taking also would violate the Pennsylvania Constitution, Art. I, § 10.

compensation to utility companies for investments stranded by the introduction of competition to the electric generation market.

PP&L has a constitutional right to fair compensation for its reasonable and prudent investments in facilities that were used and useful in providing public service. That right to fair compensation cannot be discharged or avoided by a change in fundamental regulatory policy that destroys the value of such investments.

B. Effect on Regulated Activities

The Act will have four important effects on the regulated activities of electric utilities in Pennsylvania. First, utilities will unbundle their rates to show separately the charges for transmission, distribution and generation services, including recovery of stranded costs through the CTC. 66 Pa. C.S. § 2806(e). Second, utilities will offer open and non-discriminatory access to their transmission and distribution facilities for all qualified applicants. 66 Pa.C.S. § 2802(14). Third, utilities will continue their public purpose programs, including assistance to low-income customers. 66 Pa.C.S. § 2807(d). Fourth, utilities will offer "provider of last resort" service to any customer who elects not to choose an alternative supplier or who did not receive service from such a supplier. 66 Pa.C.S. § 2807(e).

C. Effect on Investors

The change in regulatory policy to a competitive market for electric generation reflects a fundamental change in the basic rules by which electric generation services have been provided and must allow electric utilities a fair opportunity to recover investments in facilities made uneconomic by the change in regulatory policy. Any breach of the Commonwealth's clear obligation to utility investors would be poor public policy, and would be contrary to sound economic principles, and therefore, contrary to the public's economic interest. As explained by Professor Kalt:

> Government is the promulgator and enforcer of the rules of the game. If it uses its power to alter those rules after other parties have sunk investments into the game, such action imposes costs on all of the citizens under its jurisdiction. As underdeveloped and unstable countries around the world have taught us, instability in the rules of the game by which investors must play is the recipe for failure. In a world of intense international competition and capital that can flee from policy instability, regulatory change in Pennsylvania's electric power sector that would have the effect of stranding utilities' previously incurred costs would be decidedly contrary to the public's interest in a healthy Pennsylvania economy. One immediate consequence of policy instability would be a higher cost of capital for firms investing in Pennsylvania, particularly transmission and distribution utilities. PP&L St. 1, pp. 13-14; *see also* PP&L St. 18-R, p. 11.

D. Mitigation

Under Section 2808(c)(4) of the Act, in determining the level of stranded costs to be recovered, the Commission is to consider the extent to which the electric utility has mitigated generation-related stranded costs. PP&L's mitigation efforts have been substantial and successful in reducing its stranded costs. The ultimate proof of the effectiveness of PP&L's pre-restructuring mitigation is PP&L's success in controlling its rates, which the Act declares to be of "equal importance" with future efforts to mitigate stranded costs. *See* 66 Pa.C.S. § 2808(c)(5). The interplay between past efforts in controlling rates and stranded cost recover is clearly illustrated in this case. Because of PP&L's past efforts to keep rates low, the rate cap limits PP&L's ability to recover all of its stranded costs. It would, of course, be unjust and contrary to the Act to require PP&L to forego recovery of its stranded costs beyond that already denied it by application of the rate cap.

1. Pre-Restructuring Mitigation

a) PP&L's Pre-Restructuring Rates

Stranded costs related to electric generation facilities are driven by the difference between revenue requirements associated with these assets and the projected market price of electric generation. *See* Section 2803 of the Act (definition of "transition or stranded costs") and PP&L St. 2, p. 5. Consequently, a major determinant of an electric utility's stranded costs related to electric generation facilities is its level of rates for recovery of revenue requirements associated with its generation facilities.

PP&L, as a result of substantial efforts, has successfully maintained its rates at a low level. PP&L's success in keeping its rates at a low level is demonstrated from three different observations. First, as explained more fully below, PP&L's rates are low compared to rates of other electric utilities. Second, PP&L has filed relatively few base rate cases before this Commission in recent years, and those rate cases have been substantially separated in time. PP&L's two most recent base rate cases were filed on July 27, 1984 (Docket No. R-842651) and on December 30, 1994 (Docket No. R-00943271), more than a decade apart. Third, PP&L's actual, historical rates have been flat in terms of *nominal* dollars for the last ten years. PP&L Exh. SFT 3. In terms of real purchasing power, maintaining flat nominal rates for ten years is equivalent to a 25 percent rate reduction. PP&L Exh. SFT 4. By the end of the transition period, PP&L's total rates will have been flat, in nominal dollars, for 20 years. Flat nominal rates over 20 years is equivalent to a 50% reduction in rates in real terms. PP&L St. 9, p. 19, n.4.

Comparisons between PP&L's total rates and those of other electric utilities are provided at pages 16-19 of PP&L St. 9 and in PP&L Exh. SFT 2. As shown there, PECO's 1995 average rate is 9.91¢ per kWh and Duquesne Light Company's average rate is 8.92¢ per kWh. The Pennsylvania statewide average rate is 7.93¢ per kWh. PP&L's 1995 average rate of 7.21¢ per kWh is significantly lower than these other rates. In fact, PP&L's rates are now almost as low as the national average of 6.89¢ per kWh, while the spread between Pennsylvania's average rate and the national average rate has stayed relatively constant. PP&L Exh. SFT 4.

PP&L's efforts to control costs and rates have been especially beneficial to residential customers. PP&L's rates for residential service have dropped below the national average, while Pennsylvania's average residential rate has been well above the national average. PP&L Exh. SFT 5. These low rates have resulted from constant cost control efforts by PP&L. Because cost control and efficiency have become an integral part of PP&L's corporate culture, a comprehensive list of PP&L's pre-structuring mitigation efforts would include a description of virtually every project undertaken by PP&L. Although it would be impossible for PP&L to provide a complete list of all its many cost-containment and reduction efforts in all facets of its operations, PP&L has compiled the following examples of its efforts to control costs and maintain rates at reasonable levels. PP&L St. 2, p. 6.

b) Refinancings

In recent years, PP&L has taken advantage of reductions in the cost of capital to refinance higher cost securities. The success of PP&L's efforts can be demonstrated by reference to its two most recent base rate case orders. In PP&L's 1984 rate case, *Pa. P.U.C. v. PP&L*, 59 Pa. PUC 332, 390 (1985), the Commission approved a long-term debt cost rate of 11.27 percent. In PP&L's 1994 rate case, in contrast, the Commission approved a long-term debt cost rate of 7.97 percent. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, p. 183 (September 27, 1995). During the 10½ years between rate cases, PP&L reduced its long-term debt cost rate by almost 30 percent.

Similarly, PP&L was able to reduce substantially its cost rate of preferred stock. In its 1985 base rate case, the Commission approved a preferred stock cost rate of 9.89 percent. *Pa. P.U.C. v. PP&L*, 59 Pa. PUC at 390. By the 1994 base rate case, PP&L had reduced its preferred stock cost rate to 7.31 percent, a reduction of approximately 26 percent. *Pa. P.U.C. v. PP&L*,

Docket No. R-00943271, p. 183 (September 27, 1995). These capital cost reductions reduced PP&L's revenue requirement in its 1994 base rate case by $100 million. PP&L St. 2, pp. 6-7.

c) Operation and Maintenance Cost Reductions

After its 1985 rate case, PP&L is in controlling costs permitted it to postpone filing another base rate case for over ten years. PP&L St. 2, pp. 7-8. PP&L's cost containment initiatives included elimination of functions that had become unnecessary, restructuring of the corporate offices and reengineering of critical processes to combine functions where feasible. The success of PP&L's efforts is shown by a comparison of PP&L's operation and maintenance production costs (excluding fuel) over time, both in terms of nominal dollars and as adjusted for inflation. PP&L St. 2, p. 7.

	1986 FERC Form 1	1986 Adjusted for Inflation	1996 FERC Form 1
		($Millions)	
Steam Production	$139.1	$189.0	$142.2
Nuclear Production	118.2	160.6	155.8
Hydraulic Production	6.1	8.3	6.3
Other Production	1.8	2.4	2.7
	$265.2	$360.3	$307.0

As shown above, PP&L's operation and maintenance production costs have increased by only 16 percent over 10 years and, adjusted for inflation, have actually declined by 15 percent.

d) Employee Reductions

PP&L continuously has reduced costs through increasingly efficient utilization of employees. PP&L St. 2, p. 8. PP&L's efforts are exemplified by the early retirement program offered to 851 employees in 1994 who would reach age 55 by December 31, 1994. A total of 604 employees accepted the offer of the early retirement program.

Over a longer time horizon, from 1985 through 1996, PP&L reduced its employee complement by 2,005 regular full-time employees, almost 24 percent of its 1985 work force. PP&L, however, has implemented work force reductions in a manner to minimize adverse effects upon former employees. Most reductions occur through normal attrition, early retirement programs and voluntary severance programs.

e) Inventory Reductions

In 1991, PP&L modified its accounting for spare parts at power plants. Prior to 1991, spare parts were expensed when purchased. After 1991, spare part costs were recorded as inventory on PP&L's balance sheet. Contemporaneously, with the Commission's approval, PP&L changed its ratemaking treatment of spare parts. Consequently, PP&L was able to pass back $94 million to customers over 5 years through a rate credit mechanism. PP&L St. 2, pp. 8-9. Following this change in accounting, PP&L also reviewed its spare parts inventories to identify obsolete or excessive items. As a result of the review, PP&L wrote off $35 million of inventory, further mitigating PP&L's stranded costs. PP&L St. 2, p. 9.

f) Cost Effective Nuclear and Fossil Plant Operations

(1) Containment of Nuclear Generation Facility Costs

Approximately 63 percent[11] of PP&L's stranded costs relate to the Susquehanna Steam Electric Station ("Susquehanna"). PP&L has undertaken significant measures that have reduced stranded costs associated with this facility. *See generally* PP&L St. 2, pp. 9-11.

PP&L completed Susquehanna as quickly as possible in order to minimize associated capital costs. Such efforts were particularly important because while Susquehanna was under construction, inflation, short-term interest rates, and consequently, rates for the allowance for

---

11 $2,852 million ÷ $4,499 million. See PP&L Exh. JRS 1A.

funds used during construction, were relatively high.[12] As a result of these and other measures, PP&L was able to complete construction of two large nuclear units at a total cost of approximately $3.6 billion for 1,890 megawatts of capacity or approximately $1,900 per kilowatt. Other plants in Pennsylvania and in the United States, which were constructed contemporaneously with Susquehanna, were completed at significantly higher costs per kilowatt. PP&L St. 2, p. 10.

Following completion of Susquehanna, PP&L pursued claims against the containment supplier, General Electric. PP&L settled its claims against General Electric in 1991. Because Susquehanna already was recognized in rate base and because PP&L was in the decade-long hiatus between rate cases, PP&L obtained Commission approval to refund the jurisdictional amount of the net settlement proceeds to customers through a special rate credit mechanism that returned $55 million to customers. PP&L St. 2, p. 10.

In addition, PP&L has operated Susquehanna at high a capacity factor. Because nuclear power plants have high capital costs, but low fuel costs, their efficiency depends upon a high capacity factor — the more a nuclear generating plant operates, the more fuel savings it can provide. Susquehanna's excellent operating record has reduced PP&L's energy costs and customers' rates. Further, because this historical operating record has been projected to continue in the future, it reduces PP&L's stranded costs in this proceeding. PP&L St. 2, pp. 10-11. More recently, between 1991 and 1995, PP&L spent $45 million to upgrade Susquehanna's capacity by 90 megawatts, or $500 per kilowatt, producing additional energy cost savings for customers.

---

12 Susquehanna Unit 1 commenced commercial operation on June 8, 1983, and Susquehanna Unit 2 commenced commercial operation on February 12, 1985. *Pa. P.U.C. v. PP&L*, 59 Pa. PUC 332, 337, n.1 (1985). For measures of inflation and short term interest rates, see, *e.g.*, OTS Exh. SR-3, Schedule 4.

(2) Savings in Fossil Plant Operations

PP&L has operated its fossil fuel generating plants efficiently and has made substantial expenditures to assure the continued viability of low cost, coal-fired generating stations. These generating stations benefit customers through low fuel costs and increased interchange sales, which both lower retail rates. PP&L St. 2, p. 11.

PP&L also has invested to improve the efficiency of other fossil fuel plants. For example, PP&L converted its Martins Creek Units 3 and 4 to gas/oil dual fuel capability. PP&L now can burn gas or oil, whichever costs less, at these units, which makes them more cost effective. PP&L St. 2, p. 11.

g) Non-Utility Generator Contract Cost Reductions

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), PP&L was compelled to enter into long-term supply contracts with NUGs. Rates in these agreements were based upon future market prices of fuels, which were projected at the time the contracts were executed. At that time, the price of oil was expected by now to be nearing $100 a barrel. PP&L St. 18-R, p. 22. NUG contract prices have turned out to be greater than PP&L's avoided costs of replacement generation or purchased power. In order to reduce the level of stranded costs resulting from uneconomic NUG contracts, PP&L has undertaken several actions which have reduced stranded costs by $100 million.

h) Economic Development Initiatives

As explained previously, the essence of pre-restructuring mitigation is keeping pre-restructuring rates low. There are two sides to keeping rates low. One side is cost containment, which has been explained above. The other side is increasing sales and revenues so that fixed costs can be recovered over a greater number of billing units, thereby decreasing the average cost per unit.

On the sales side of the equation, PP&L has promoted economic development in order to retain existing and to attract new industrial load. PP&L has been "prospecting" nationally to attract businesses to its service territory. PP&L has worked with regional economical development organizations and has provided economic development loans in order to attract industrial load and jobs to its service territory. PP&L has adopted specific tariff provisions and rates, subject to the Commission's approval, to promote economic development, including the interruptible service rates, Economic Development Initiative ("EDI") credits, Industrial Development Initiative ("IDI") credits and Demand Free Days. PP&L St. 2, p. 13. These initiatives have helped PP&L avoid rate increases and have generated thousands of new jobs in PP&L's service territory. PP&L St. 2, p. 13-14.

2. Post-Restructuring Mitigation

a) Foregone Recovery Under the Rate Cap

PP&L has demonstrated, in this proceeding, stranded costs of $4.5 billion. PP&L St. 2, p. 18. PP&L has proposed in this proceeding, however, a CTC that will recover only $4.0 billion, resulting in a shortfall of $500 million. PP&L St. 10-R, p. 3. Under PP&L's proposal, its shareholders will bear an estimated $500 million of stranded costs.

Moreover, the CTC revenue shortfall is based upon projected future electric generation market prices. However, PP&L's filing assumes that most of its fixed costs will be recovered as a result of future electricity market price and sales increases. If PP&L's projections overstate actual future market prices, PP&L's total revenues will decrease and its unrecovered stranded costs will increase commensurately.

b) Depreciation Swap

Pursuant to Section 2808(c)(4)(iii) of the Act, one of the mitigation steps that electric utilities are to consider is reallocating depreciation reserves from transmission and distribution plant accounts to generation accounts. In its filing, PP&L has proposed to transfer $205 million of its depreciation reserve related to transmission and distribution plant to the accumulated reserve for depreciation associated with Susquehanna. The transfer of the depreciation reserve, together with the changes in the reserve for deferred income taxes, would reduce PP&L's stranded costs by $317 million. PP&L St. 2, p. 17.

This proposal arises from PP&L's 1994 base rate filing in which the Commission granted PP&L's request to extend the regulatory service lives of its transmission and distribution plant. If PP&L had used these longer lives commencing at the time that present transmission and distribution facilities originally were placed into service, the accumulated depreciation reserve for these facilities would have been $205 million less than the level currently recorded on PP&L's books and records. It was this change in depreciation lives that made the $205 million of depreciation reserve available to be transferred to generation plant accounts.

Despite the fact that the "depreciation swap" would decrease stranded costs, OCA, the Department of Defense and the Environmentalists have opposed the proposed transfer of the depreciation reserves. They have raised four purported grounds for rejecting PP&L's proposal, including:

> (1) the transfer will shift costs between rate classes at the jurisdictional level and between retail and wholesale customers;
>
> (2) the transfer will lead to load growth, with adverse environmental impacts;
>
> (3) the transfer will reduce shareholder exposure while increasing regulated transmission and distribution costs; and

(4) the transfer will result in transmission and distribution customers paying costs twice.

None of these grounds have validity.

First, there is no cost shifting between rate classes at the retail jurisdictional level because PP&L's unbundled rates were derived from its cost of service study approved in the 1995 base rate case, which was not modified to reflect the swap of the depreciation reserve. PP&L St. 3-R, pp. 12-13. PP&L's proposal will not result in cost shifting between federal and state jurisdictions. Any possible cost shifting will be avoided by PP&L's creation of a regulatory asset applicable to the transmission and distribution functions which equals the allocated depreciation reserve to be transferred. Under this proposal, the net decrease to the depreciation reserve for the Pennsylvania jurisdictional portion of the transmission and distribution function will equal the Pennsylvania jurisdictional portion of the increase to the depreciation reserve for the nuclear generation function.

Second, it is difficult to imagine that the small change in rates resulting from the depreciation swap would affect customers' usage patterns. PP&L St. 8-R, p. 53. Further, one purpose of the Act is to achieve lower rates to improve the economy of Pennsylvania. *See generally*, Section 2802. The Act encourages mitigation of stranded costs for the purpose of reducing electric utilities' CTCs, thereby lowering rates. Arguments against reducing rates are contrary to the express purpose of the Act.

Third, customers are protected from overrecovery by electric distribution companies of transmission and distribution costs through the applicable rate cap. Consequently, customers cannot be harmed by a reduction in PP&L's stranded costs. Further, the "depreciation swap" is one of the mitigation procedures expressly contemplated in Section 2808(c)(4)(iii) of the Act. PP&L St. 8-R, p. 53.

PP&L's proposal to transfer a portion of the depreciation reserve applicable to its transmission and distribution facilities to nuclear generation facilities, in order to reduce stranded costs, should be recognized as appropriate mitigation.[13]

c) Operation and Maintenance and Administrative and General Cost Reductions

In computing stranded costs, PP&L has projected approximately $513 million in reductions to future operation and maintenance and administrative and general costs. PP&L St. 2, p. 16 These projections reflect a continued commitment to cost containment and an estimate of the reductions that PP&L expects to achieve. However, if PP&L is unable to achieve the projected $513 million of future cost reductions, PP&L and its investors will bear the costs that PP&L is unable to avoid.

d) Treatment of the 1999 Depreciation Change

In its most recent base rate case, PP&L proposed to modify the method by which it accrues depreciation on Susquehanna. PP&L had used a modified sinking fund method to moderate rate increases associated with placing these units into rate base. PP&L proposed, commencing January 1, 1999, to switch to a straight line method of depreciation, under which it would experience a reduction in its annual depreciation accrual of an estimated $70 million. In conjunction with its proposal to change the depreciation method, PP&L proposed also to reduce base rates effective January 1, 1999, to reflect the effects of this switch in depreciation method.

---

[13] PP&L notes that the PUC rejected a proposed depreciation swap in PECO's Restructuring Proceeding. PECO Order, p. 97. That adjustment is *not* the same adjustment proposed by PP&L in this case. PP&L's excess transmission and distribution depreciation reserve resulted from a new study extending the lives of those assets which was reviewed and approved by the PUC in PP&L's 1995 base rate case. The reduced depreciation expense resulting from this study therefore has already been flowed through to customers through lower rates.

The Commission approved PP&L's proposal. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, pp. 112-13 (September 27, 1995).

As a result of the fundamental changes in regulatory policy under the Act which imposes rate caps on PP&L from January 1, 1997 through 2005, such a rate reduction is no longer appropriate. PP&L St. 10, pp. 9-10. Under prior rate regulation, PP&L could have filed base rate cases in 1997, 1998 or anytime thereafter in order to recover increased costs of providing electric service. Therefore, it was reasonable to flow through to ratepayers the effects of the change in depreciation method. Under the Act, however, PP&L cannot increase base rates commencing January 1, 1997 and for nine years thereafter. Under these circumstances, it would be far more appropriate for the Commission to permit PP&L to use the reduction in annual Susquehanna depreciation expense to accelerate amortization of regulatory assets and post-transition NUG costs. PP&L St. 2, pp. 18-19. Pursuant to the Act's policy to mitigate stranded costs, the reduction in the annual depreciation accrual for Susquehanna should be used to mitigate stranded costs, as proposed by PP&L.

e) Reduction in Planned Capital Expenditures

In late 1995, PP&L announced plans to reduce capital expenditures over a 5-year period by $671 million. Of this total, $486 million represented reductions in plant expenditures for fossil generating units. Reductions in capital investment in generating facilities mitigates PP&L's stranded costs. PP&L St. 2, p. 9.

f) OCA's Criticisms of PP&L's Mitigation Efforts Are Meritless

Although OCA makes several vague criticisms of PP&L's mitigation of stranded costs, only two items are specific. OCA contends that PP&L has not recognized productivity gains in calculating stranded costs and that PP&L has not recognized the full value of its own assets.

These specific adjustments are addressed in detail in Section V. D. As explained therein, these adjustments are without merit.

E. Allocation of Stranded Costs between PP&L and Ratepayers

Several parties in this proceeding have suggested that stranded costs should be "shared" between PP&L and its ratepayers by various artificial and arbitrary means. *See, e.g.*, OCA St. 1, pp. 29-32; OTS St. 1, pp. 20-21; PPLICA St. 1, pp. 15-22. In making these contentions, these parties misapply Section 2804(13) of the Act, which provides as follows:

> Consistent with Section 2808 (relating to competitive transition charges), the commission has the power and duty to approve a competitive transition charge for the recovery of transition or stranded costs it determines to be just and reasonable to recover from ratepayers.

It is clear that parties misconstrue and misapply the term "just and reasonable."

Virtually all of PP&L's plant investments have been reviewed by the Commission in prior base rate cases and included in rate base as prudently-incurred and used or useful in the public service. PP&L's most recent base rate case was based upon a future test year ended September 30, 1995. *Pa. P.U.C. v. PP&L*, Docket No. R-00943271, p. 1 (September 27, 1995). No generation units have been placed in service since this test year. Only the relatively minor plant additions placed into service since September 30, 1995, could have been the subject of prudence contentions in this proceeding, and no such contentions have been raised. Therefore, all of PP&L's rate base and operating expenses are "just and reasonable" as that term is used in Section 1301 of the Public Utility Code, 66 Pa.C.S. § 1301, to establish a utility's rates. It follows that PP&L's stranded costs arise from PP&L's present "just and reasonable" rates. The Act should be interpreted to allow recovery of such stranded costs arising from investments and expenses that were determined to be proper in setting present rates.

In the PECO Order, the Commission ruled that in determining a just and reasonable level of stranded cost recovery under Section 2808(c)(3), the Commission must consider whether "the utility's efforts to mitigate stranded investment have been "reasonable under all of the circumstances[.]" PECO Order, p. 67 (citing Section 2808(c)(4)). The Commission noted that Section 2808(c)(4) requires "equal consideration" of the utility's "efforts undertaken over time . . to reduce or moderate rate levels." As noted above, with some of the lowest rates in the state, PP&L has satisfied this standard. Indeed, it is application of the rate cap at these low rates that prevents PP&L from recovering up to $500 million in stranded costs.

Parties in prior utility base rate proceedings have contended that certain otherwise "just and reasonable" expenses of public utilities should be "shared" between ratepayers and the utility on policy grounds similar to contentions raised by various parties in this proceeding. Such contentions have been uniformly rejected by Pennsylvania appellate courts. *See, e.g., Butler Township Water Co. v. Pa. P.U.C.*, 81 Pa. Comwlth. 40, 473 A.2d 219, 221-22 (1984); *T.W. Phillips Gas & Oil Co. v. Pa. P.U.C.*, 81 Pa. Comwlth. 205, 474 A.2d 355, 366-67 (1984). Similarly, the sharing proposals should be rejected in this proceeding.

Significantly, when the General Assembly wishes to mandate "sharing" mechanisms, it knows how to do so. When considering electric generation units with excess capacity that is not used or useful in the public service or electric generating units which experience excessive outages, the General Assembly has set forth procedures for such determinations and specified the sharing mechanisms that the Commission is authorized to employ. *See* 66 Pa.C.S. § 1322 (as to excessive outages) and 66 Pa.C.S. § 1323 (as to excess capacity). The Act, in contrast, contains no such provisions.

Moreover, the OCA's proposed stranded cost proposal would have a devastating impact on PP&L. To demonstrate the importance of allowing PP&L to recover its stranded costs, the Company prepared a financial analysis comparing the effects of PP&L's recovery of approximately $4 billion of stranded costs with the results that would occur under OCA's initial proposed allowance of one tenth the level of stranded costs proposed by PP&L, or $0.4 billion. This analysis is provided in PP&L St. 8-R, pp. 18-29.[14]

The starting point of this analysis was PP&L's results of operations for 1996. PP&L then brought forward the results of operations for 1996 to 1999, when a substantial portion (one third) of PP&L's customers will have access to the competitive generation market. In order to simplify the analysis, PP&L recognized only changes resulting from the Financial Accounting Standards Board's Statements of Financial Accounting Standards 5, 71, and 101. These Standards require PP&L to recognize as expenses during the transition period all stranded costs associated with regulatory assets and purchases from NUGs.[15] These expenses will increase PP&L's expenses over the seven-year transition period by $935 million. PP&L St. 8-R, pp. 20-21. The analysis also recognizes that this increase in expenses will be offset to a very limited extent by the $70 million reduction in Susquehanna depreciation accrual commencing in 1999. PP&L St. 10, p. 9. Using PP&L's simplified approach, the pro forma return on equity for 1999, under PP&L's proposal, would be 10.52%. PP&L St. 8-R, p. 23.

OCA's proposal of a 32% rate reduction would produce sharply different results. Under OCA's proposal, PP&L's 1999 *pro forma* return on equity would be a *negative* 9.65%. PP&L would experience an operating loss each and every year of the transition period. Under OCA's proposal, PP&L would be unable to pay dividends or interest on debt.[16] If OCA's proposal were

---

[14] In its surrebuttal testimony, OCA increased its stranded cost allowance to approximately $1.0 billion. OCA St. 1-S, p. 7. This small increase has no material effect on the financial results outlined below. Tr. 1543-45 (8/26/97).

[15] It should be emphasized also that PP&L does not recognize in this analysis any increment in expense to accelerate recovery of the $3.6 billion of stranded generation assets, which would be required if there were no assurance of recovery of such amounts.

[16] It should be noted also that PP&L's shareholders have not benefited from appreciation in the price of stock. PP&L's stock price presently is essentially at the same level it was 10 years ago. PP&L

adopted, the generation portion of PP&L's business would fail and the ability of PP&L to maintain the transmission and distribution portion of its business would be endangered. PP&L's ability to be the supplier of last resort, to obtain credit, and to maintain adequate system reliability all would be compromised. PP&L St. 8-R, pp. 24-27.

It should be emphasized that the above analysis is a "best case" scenario. Realistically, PP&L's situation would be much worse. In fact, PP&L would be required to record a substantial impairment write-off for Susquehanna because OCA calculates a value for the plant of $826 million, which is far less than its book value of approximately $2.8 billion. PP&L St. 8-R, pp. 28-29. This additional $2 billion impairment has not been reflected in the analysis provided in PP&L St. 8-R.

This financial analysis was calculated using PP&L's projected market price of electric generation. If PP&L's projections are accurate and if the Commission accepts OCA's proposals, the result would be a financial disaster for PP&L, its investors and those who rely on its service. If, however, the market price of electric generation turns out to be greater than projected by PP&L, as projected by OCA, ratepayers nevertheless are protected by the rate caps. They would not be required to pay more than they do presently.[17] As articulated by Dr. Kahn:

> The risk to the Company—of the stranded cost estimates being high or low—are *not symmetrical.* Symmetry would require an equal likelihood of over-recoveries and underrecoveries in the event of the Commission's estimate of stranded costs turning out, respectively, too high and too low. But if the Commission accepts the OCA estimates, the Company will be permanently denied the recovery of its sunk or strandable costs to the extent those projections are too low, whereas it will overrecover, if the projections are too high, *only* under a very particular scenario of the relationship, before and after 2006, between competitive rates and the price

---

St. 8-R, p. 26.

[17] OCA's unsupported contention, OCA St. 1-S, p. 12, that financial results would significantly improve if its market price turns out to be right is simply not true. Tr. 1543-45 (8/26/97).

ceilings imposed by the Act.

* * *

> I think the statute obliges the Commission to choose a figure that it regards as most probable. But the asymmetry I have described dictates that it neither succumb to the temptation, to which OCA is inevitably subject, to err on the low side *or* even simply to split the difference between the estimates of OCA and the Company, *even if* it regarded them of equal validity (on the ground that PP&L has a corresponding temptation to offer exaggerated estimates). Over and beyond these considerations of the asymmetrical risks involved in the OCA's recommendations, the Commission has of course an obligation to weigh the evidence presented by Dr. Jones, on the one side, and the OCA witnesses, on the other, and decide which of them seems the more realistic. PP&L St. 18-R, pp. 32-33.

OCA's proposed level of stranded costs is completely unjustified and does not represent any reasonable even-handed sharing of risks associated with stranded costs.

III. STRANDED COST CALCULATION METHODOLOGY

A. PP&L's Calculation Of Stranded Costs

The Act generally identifies three categories of stranded costs: (1) regulatory assets and other deferred charges, the unfunded portion of nuclear plant decommissioning costs, and cost obligations under contracts with NUGs; (2) costs related to the cancellation, buyout, buydown or renegotiation of NUG power supply contracts; and (3) other generation-related expenses, principally plant and fossil decommissioning costs. 66 Pa.C.S. § 2803. PP&L's Restructuring Plan filing includes expenses from each of the categories identified by the Act. PP&L St. 8, p. 3. For stranded cost calculation purposes, PP&L divided its claimed expenses into four categories: (1) nuclear generation; (2) fossil generation; (3) NUGs; and (4) generation-related regulatory assets. Utilizing a regulatory or revenue requirement methodology (the "regulatory method"), PP&L determined that it has approximately $4.5 billion in stranded costs after mitigation.[18]

The OCA and PPLICA oppose the Company's method of calculating stranded costs related to generating plant, and recommend that the Commission adopt the asset value method proposed by PECO in its Restructuring Plan proceeding (Docket No. R-00973953). OCA St. 1, p. 14; PPLICA St. 2, p. 10. The OCA and PPLICA, however, propose to calculate stranded costs associated with regulatory assets using the regulatory method. As explained below, these parties' hybrid approach is flawed because it is based on an inconsistent and improper application of the asset value method that would produce arbitrary and unreasonable results and would deny PP&L reasonable stranded cost recovery. PP&L's regulatory method is appropriate and fully consistent with the Act and should be approved. In the alternative, if the asset value method is used, it should be applied correctly and consistently, as explained in Section III.C, *infra*.

B. The Regulatory Method vs. The Asset Value Method

As defined in the Act, stranded costs are the present value of net generation-related costs that would be recoverable under traditional cost-of-service regulation, but which may not be recoverable in a competitive market and which remain after mitigation efforts. 66 Pa.C.S. § 2803. The regulatory method of calculating nuclear and fossil generating plant stranded costs compares the annual cost-of-service revenue requirements for each generating plant to the projected annual revenues each plant would receive from the sale of its output using market-based prices for each year beginning January 1, 1999, to the end of its remaining service life. PP&L St. 8, p. 4. The Company applied a PUC-jurisdictional percentage to the annual excess or

---

[18] In its initial filing, PP&L estimated that it had approximately $4.6 billion in stranded costs. PP&L Exh. JRS 1, p. 1. The Company subsequently revised its claim to reflect an error in its original calculation. The Company's final stranded cost claim is $4,499,922,000. *See* Tables B and C.

deficiency, and discounted the resulting stream of annual excesses or deficiencies to present value at January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital PP&L St. 8, p. 4; PP&L Exh. JRS 1, p. 1.

In contrast, the asset value method compares the present value of revenues, less cash expenses, that could be earned from generating facilities in a competitive market, with the sum of the current book value of generation and regulatory assets. PP&L St. 8-R, p. 7. Under the asset value method, the difference between this net market value and current book value equals stranded cost.

While PP&L initially considered utilizing the asset value method to calculate stranded costs, several considerations favored the regulatory method. PP&L St. 8-R, pp. 5-7; PP&L St. 19-R, pp. 15-16.

First, the regulatory method is simple to understand and to apply because it essentially uses a series of future test years, a concept familiar to the Commission. All revenues and expenses are reflected in the time period in which they occur.

Second, a variety of conceptual issues arising under the regulatory method, *e.g.*, the treatment of current and deferred income taxes, previously have been resolved by the Commission under traditional cost-of-service regulation. Thus, the regulatory method allows the Commission to apply existing rules and accepted assumptions in calculating stranded costs.

Third, the regulatory method is fully consistent with the Act. Specifically, Section 2803 of the defines stranded costs as the "known and measurable net electric generation-related 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* in a competitive generation market and which the commission determines will remain following mitigation by the electric utility." 66 Pa.C.S. § 2803 (emphasis added). Under traditional rate regulation, utilities are allowed a fair opportunity to recover their revenue requirement. Consequently, revenue requirement is the proper starting point for the determination of stranded costs of generating plants. The Act defines stranded costs based on a comparison of revenue requirements under traditional regulation with revenues projected in a competitive market. The regulatory method properly implements this statutory approach.

Fourth, the regulatory method prevents an electric utility from deriving an unfair benefit from the transition to competition. As explained above, the regulatory method is designed to ensure that, at most, a utility may only receive the level of revenues that it would have received under current Commission-approved rates.

Fifth, the regulatory method takes into account the effects of book value on revenue requirements year by year. Therefore, the specific complexities and effects of book value, *e.g.*, changing jurisdictional allocation factors and taxes, can be considered fully under the regulatory method. As explained by PP&L witness Guth, the asset value method "glosses" over such complexities because "there is no particular economic meaning to a relationship between, on the one hand, book value based upon accounting conventions for depreciation and, on the other, market value that a willing buyer would offer a willing seller in an arms length transaction." PP&L St. 19-R, p. 15.

Application of the asset value approach presents numerous problems and complexities. For example, the asset value method *cannot* be used to calculate the regulatory assets. OCA and PPLICA recognize this shortcoming and purport to use the revenue requirement method for regulatory assets, while retaining the asset value method for plant assets. The result is a mixed, hybrid approach which introduces substantial (and needless) complexity and causes serious errors in the OCA and PPLICA presentations.[19]

PP&L anticipates that the OCA and PPLICA will rely on the Commission's recent Order in the PECO Restructuring proceeding to support their recommendation to use the asset value methodology in this case. PP&L respectfully submits that the PECO Order does not support the use of the asset value method in this case. First, it is important to note that, *when properly applied, both the regulatory and asset value methods should produce comparable results because they theoretically measure the same costs.* PP&L St. 19-R, pp. 9-14. As explained by Mr. Guth, the two methods use the same inputs, with one exception. The asset value method utilizes book value, while the regulatory method utilizes the sum of revenue related to annual return on capital and revenue requirements for income taxes. These values, however, are equivalent if two factors are kept in mind:

> The first is that, in both methods, "book value" is adjusted for the same special items such as deferred income taxes. The second is that either method can be stated on an after tax basis or, alternatively, grossed up to include the revenues necessary to pay off income taxes and leave the Company whole. PP&L St. 19-R, p. 11.

When these considerations are properly addressed, the evidence shows that the asset value and regulatory methods should theoretically produce equivalent results. The problems arise from OCA's and PPLICA's inconsistent application of the asset value method, not with the asset value method itself.

Second, in PP&L's view, the PECO Order should not be interpreted as supporting the use of the asset value method over PP&L's proposed regulatory method. In fact, because none of the

---

19 Examples of such errors include the calculation of Taxes Recoverable. *See* Section V.D.6.

parties in the PECO Restructuring proceeding proposed the regulatory method to calculate stranded costs, the regulatory method simply was not at issue in the PECO Restructuring case. Thus, the Commission's brief mention of the regulatory method in the PECO Order is dicta and does not reflect a full analysis of this important issue.

Third, the OCA and PPLICA stranded cost models are not in the record in this case. Thus, even if the Commission were to adopt the PECO/OCA/PPLICA approach in this case, the record evidence simply does not include the information necessary to calculate stranded costs or to make any adjustments to such calculations. In contrast, PP&L's complete regulatory methodology is in the record and is readily available to all parties and the Commission.

C. Use of the Asset Value Model in This Case

Because the asset value methodology was used by the PUC in the PECO Restructuring case and because two major parties have used it in PP&L's case, PP&L recognizes that the PUC may wish to employ that method in this case as well. If this is the case, it is critical that the asset value method be applied completely and correctly on an "apples to apples" basis.

Application of the asset value model is problematic here because it is not in the record. Therefore, to assist the ALJ and the PUC, PP&L has included a series of tables to provide a consistent application of the asset value model and a full reconciliation of the model with PP&L's preferred revenue requirements model. These tables were prepared from data in the record. PP&L believes that this information is an essential tool to the ALJ and the PUC and is critical to a complete and fair determination of stranded costs in this proceeding.

Table B provides a summary of PP&L's $4.5 billion stranded cost claim under the regulatory method. Table C provides a calculation of stranded costs using the asset value method. Finally, Table D provides a reconciliation of the differences between the PP&L and OCA proposals using the asset value method and provides a cross-reference to the Section of the

Brief where each adjustment is discussed. If the PUC elects to use the asset value method, Table D should be used to derive the value of any adjustments.[20] Of course, changing one item will likely have secondary effects on other figures which would have to be reconciled in the Company's compliance filing.

IV. MARKET PRICE OF ELECTRICITY

The forecast of prospective market prices of electricity is the critical first step in determining the competitive market value of PP&L's generating assets. These electricity prices are used to develop market revenues for each plant on an annual basis. The market revenues are then subtracted from revenue under regulation (see Section V) to determine the stranded costs associated with PP&L's generating plants.

The prospective market prices for electricity are comprised of two components: The price of capacity and the price of energy. Customers will pay for the right to draw upon PP&L's generating assets when needed. These are payments for capacity. Customers also will pay for electric energy as they use it. These are payments for energy. While both energy and capacity prices are important in evaluating the competitive market value of PP&L's generating assets, energy prices are far more significant because they will represent approximately 90% of revenues received for electricity.

Three witnesses in this proceeding have estimated prospective market prices for electricity (PP&L witness S. Jones, OCA witness D. Smith and PPLICA witness R. Falkenberg).[21] Each witness has provided an estimate of future capacity and energy prices. Only

---

[20] Please note that the amount of the adjustments in Table D are often significantly different from the numbers appearing in the text of the Brief, which is presented on a revenue requirements basis. The two methods utilize different starting points for analysis and therefore yield different adjustments.

[21] Mr. Smith and Mr. Falkenberg presented market price projections in the PECO Restructuring proceeding, along with three witnesses on behalf of PECO. Dr. Jones did not testify in that proceeding.

PP&L's estimates reflect reasonable and consistent assumptions concerning future fuel prices and inflation as well as a tightening of the available capacity early in the next century.[22]

In general, witnesses for OCA and PPLICA estimate that market prices for electricity will rise sharply in the future. These estimates are flawed because of estimating biases built into their market price models and because of errors in input assumptions (principally fuel prices and inflation). While these errors are summarized in this Brief, the most telling criticism of these witnesses' projections is that their sharply increasing market price scenarios are contrary to the reasonably expected and intended results of electric deregulation. Their forecasts of increasing prices are also contrary to the actual results of deregulation in other areas. Simply stated, deregulation and competition produce lower prices. This is what was intended by the General Assembly. 66 Pa.C.S. §§ 2804(4) and (5). This is what has been experienced in deregulation of other industries such as airlines and trucking. PP&L St. 7-R, pp. 23-24; PP&L Exh. STJ 9. OCA's and PPLICA's overstated market prices ignore the fundamentals of competition, grossly overstate the future market prices for electricity and seriously understate PP&L's stranded costs of generation.

The Commission concluded that Mr. Smith's analysis was ". . . the most reasonable determination of future market value in the record . . . ." It did note that it found no single proposal in that proceeding "completely convincing." PECO Order, p. 88. The Commission must make a determination of the market price projections based on the record in <u>this</u> case. As explained hereinafter, PP&L has raised numerous issues concerning Mr. Smith's presentation which were not presented, and, therefore, not resolved in the PECO Restructuring proceeding.

22 PP&L's estimates were prepared by Dr. Scott T. Jones, CEO of the Economics Resources Group. Unlike the other witnesses on this issue, Dr. Jones has extensive experience in the energy industry and in projecting energy and fossil fuel prices. He was Director of Energy Studies for Atlantic Richfield Company from 1980-1985 and has provided consulting services to the oil and gas industry for more than 10 years. He has studied projections of fuel prices and the relationship of various fossil fuel prices, published articles on such issues and testified in numerous proceedings on fuel prices. PP&L Exh. STJ 1.

A. Relevant Market for Energy

In determining the capacity and energy prices that will be paid to PP&L, it is necessary to first determine the relevant market for sale of electricity and the likely sources of competition. Dr. Jones defined the supply side of the market as the generation sources in PJM and those available to serve customers in PJM. This definition includes both power sources in PJM as well as energy and capacity that can be delivered to PJM. PP&L St. 7, p. 9. The demand side of the market for generation includes all customers in PJM as well as those with access to electricity that can be delivered over lines within and connected to PJM. PP&L St. No. 7, p. 9.

The scope of the market for electricity is not controversial. All agree it is the PJM. However, as explained further with regard to energy prices, OCA's witness has made unreasonable predictions of sharp declines in imports into PJM, thereby overstating market prices.

B. Price of Capacity

1. Methodology

Dr. Jones estimated future capacity prices by beginning with current contracts for sale of capacity held by PP&L. PP&L currently makes short-term or spot capacity sales and makes sales in the forward market. PP&L St. 7, p. 45.

In forecasting future capacity prices Dr. Jones projected that capacity prices would rise sharply as PJM moved from the current state of capacity excess to a balance of demand for, and supply of, capacity. For example, as shown on Exhibit STJ 8, Dr. Jones' forecasted capacity price rises from $22/Kw year in 1999 to $50/Kw year in 2002. This rise in price corresponds to an expected elimination of the capacity excess in PJM. As explained by Dr. Jones, it is reasonable to expect that capacity prices will rise sharply as the shortage builds and that prices will drop back somewhat as new capacity is installed and customers react to higher capacity prices by switching from firm to interruptible service in response to the higher capacity prices.

PP&L St. No. 7, pp. 45-46. This is one of the many effects of a competitive market which must be anticipated in accurately reflecting future market prices. In contrast, OCA witness Mr. Smith projects continually increasing capacity prices from 1999 to 2015. OCA Exhs. DCS 7, DCS 10. PPLICA witness Mr. Falkenberg projects generally rising capacity prices with a two year reduction in prices following tightening of the capacity market in 2001. PPLICA Exh. RJF 9b.

OCA witness Mr. Smith states that his market capacity prices are based upon the carrying cost of new "peaking" capacity (presumably combustion turbines) in 2001. OCA St. 2, p. 18. A similar analysis was performed by PPLICA witness Mr. Falkenberg. PPLICA St. No. 2, p. 63. Both witnesses, and Mr. Knecht on behalf of OSBA, criticize Dr. Jones estimates of market capacity prices as insufficient to encourage investors to install new capacity when needed. As explained in the next section of this Brief, these allegations have been demonstrated to be based upon errors of analysis and incorrect assumptions.

2. Sufficiency of Market Capacity Prices to Support Additions of New Capacity

OCA, PPLICA and OSBA challenged Dr. Jones' forecast of market capacity prices as insufficient to support addition of new capacity. OCA St. 2, pp. 12-17; PPLICA St. 2, pp. 35-40; OSBA St. 1, pp. 32-34. Mr. Knecht quantified these criticisms by presenting an analysis of the carrying costs of new capacity to be installed in 2005. He concluded that Dr. Jones' capacity and energy prices were insufficient to support additions of new combined cycle capacity. OSBA St. 1, pp. 32-34. Dr. Jones refuted such analysis in his rebuttal testimony. PP&L St. 7-R, pp. 68-85; PP&L Exhs. STJ 28 and 28a. OCA and PPLICA responded to Dr. Jones in their surrebuttal testimony. OCA St. 2-S, pp. 10-20; PPLICA St. 2-S, pp. 13-33. Dr. Jones responded in rejoinder. Tr. 1385-86, 1391-96 (8/25/97); PP&L Exhs. STJ 28R, STJ 28aR and STJ 28bR.

In many ways, this "issue" is a "tempest in a teapot". Parties have raised several factors to be considered in evaluating whether capacity prices and energy prices are sufficient to support construction of new capacity. These factors are the cost of the new unit, costs of other facilities such as land and pipelines to serve the unit, and the heat rate (amount of BTUs needed to produce a Kwh of electric energy) at which the unit can be expected to operate. In order to calm the tempest, Dr. Jones presented, in rejoinder, revised Exh. Nos. STJ 28 R, STJ 28aR and STJ 28bR.

These revised exhibits make the following corrections to Dr. Jones' prior exhibits, presented in response to Mr. Knecht: 1) replace Mr. Knecht's incorrect use of average annual energy prices for <u>all</u> units with the higher energy prices that would be paid to owners of new combined cycle units during the hours when the new combined cycle units actually would be run; and 2) replace Dr. Jones' incorrect use of low heat value (LHV) heat rates with high heat value (HHV) rates to respond to OCA's and PPLICA's criticisms in surrebuttal testimony. The revised PP&L Exh. STJ 28R summarizes the rates of return that would be produced at Dr. Jones' capacity and energy prices for combined cycle units. In each case, the rate of return exceeds 12.8% and in all but one case, exceeds 13%. It also is noted that for each of the numerous units listed on Exh. STJ 28R, the unit cost and heat rates are known because these are existing technologies. Clearly, Exh. STJ 28R demonstrates that Dr. Jones' projected market prices are sufficient to support the installation of new capacity.

To further illustrate this point, Dr. Jones also presented, as part of his rejoinder testimony, Exh. STJ 32. This exhibit is designed to show the return that will be produced by Dr. Jones' prices applied to Mr. Smith's estimate of combined cycle unit costs. The second column of this exhibit, reproduced below in table form, shows Mr. Smith's estimated installed costs of a combined cycle unit. Applying Dr. Jones' energy and capacity prices, for the time period when a combined cycle unit would run, to Mr. Smith's unit costs, without adjustment, produces a 13.14% rate of return. Tr. 1409 (8/25/97). Thus, even accepting Mr. Smith's estimate of unit costs, Dr. Jones' energy and capacity prices are more than sufficient to produce an adequate return and to justify installation of new capacity.

Key Assumptions	Smith[1]	Smith Corrected[2]
Capital Cost		
Turnkey Cost	$425.00	$425.00
Switchgear Cost	$25.00	$25.00
Gas Pipeline Cost	$4.00	$4.00
Electrical Transmission Cost	$4.00	$4.00
Land Cost	$0.10	$0.10
Infrastructure	$9.00	$9.00
Plant Development/Siting	$10.00	$10.00
Interest During Construction	$19.00	$0.00
All-in Costs	$496.10	$477.10
All-in Costs @ Summer Rating	$550.00	$520.00
Return on Equity		
STJ Capacity Price	13.14%	13.87%

Notes:

(1) See OCA Exh. DCS 14.
(2) Interest during construction is properly accounted for in the NPV calculation. "All-in Costs @ Summer Rating" includes only turnkey costs.

The third column of PP&L Exh. STJ 32 and the above table make adjustments to the unit costs estimated by Mr. Smith to correct the errors in Mr. Smith's analysis. First, it eliminates the interest during construction cost because this amount, as agreed to by Mr. Smith on cross examination, is accounted for when using a net present value calculation. Tr. 1529 (8/25/97). Second, it also eliminates Mr. Smith's erroneous gross up of land, infrastructure and gas pipeline costs to reflect the effects of the lower summer capacity rating of the unit. As explained by Dr. Jones, these costs are fixed and are not affected by decreases in capacity in the summer. Tr. 1395 (8/25/97). When these corrections are reflected, the table above demonstrates that Dr. Jones prices would be sufficient to generate a 13.87% rate of return on the corrected unit costs -- a return rate that is significantly above that which any party would contend is necessary to generate capacity additions.

The contentions of various parties that Dr. Jones' market capacity prices are "insufficient" to support additions of new capacity are clearly unsupported by the record. The above analysis demonstrates that PP&L's forecasted prices are sufficient to support such additions at even today's costs and heat rates. As unit costs decrease and/or heat rates improve (less fuel to produce each Kwh) the rates of return produced by new units will be even higher.[23] Accordingly, the market capacity prices forecasted by Dr. Jones are demonstrated to be reasonable.

The issue, therefore, is not whether Dr. Jones' capacity prices are sufficient to support the installation of new generating facilities. Instead the issue is the justification, if any, for the much higher capacity prices forecasted by Messrs. Smith and Falkenberg. The higher capacity and energy prices projected by these witnesses indicate that investors in new generation will achieve rates of return well in excess of the 13.14% to 13.87% that is shown in the table on page 53 of this Brief. Neither witness has provided an explanation why investors will demand capacity prices that will produce returns in excess of 14%. This is one of several areas where the intervenor witnesses' recommendations must be tested by real world standards. It is simply not credible to believe that investors will demand capacity prices that will produce returns in excess of 14% in an environment where there are competing projects. OCA's and PPLICA's witnesses ignore the effects of competition in lowering prices and provide no real-world basis to support their projected capacity prices. In contrast, PP&L's prices are based upon current contracts and have been demonstrated to produce returns that are sufficient to install new generation. For these reasons, PP&L's capacity prices are the only capacity prices that are justified by the record in this proceeding, and they should be accepted. As shown in Table D, the use of OCA's higher

---

[23] The calculations in PP&L Exhibit STJ 32 are based upon a heat rate of 7000 Btu/Kwh, which is very conservative. Mr. Smith estimated a future heat rate of 6700 Btu/Kwh which, if used in PP&L Exh. STJ 32, would increase rates of return even further because the unit would consume less fuel per Kwh produced. Tr. 1395 (8/25/97).

capacity prices would unreasonably increase projected market value by $38.446 million and understate PP&L's stranded costs by an equal amount.

C. Price of Energy

Three witnesses have projected energy prices in this proceeding. Each witness has used a model to estimate future energy prices. The principal inputs of these models are fuel prices, operation and maintenance expenses for each generating unit, inflation, efficiency of each generating unit, customer demands for energy and imports of energy from outside the PJM pool. Accordingly, one of the primary controversies in this proceeding is the appropriateness and reasonableness of the inputs to the models. However, before addressing those inputs, issues concerning the appropriate model to employ must be resolved.

1. Choice and Use of Models

Each of the witnesses agrees that the model should be designed to determine the marginal cost of the last generating unit dispatched to PJM each hour. Dr. Jones explained the theory of his model as follows:

> Suppliers, like PP&L, seeking to supply load in the PJM-ISO region will bid prices into the regional capacity and hourly energy markets. These bids represent the prices at which generators are willing to supply electric generation services. If they are called upon in any hour, generators will behave as "price-takers", receiving a market price for electricity they generate. In competitive markets, where suppliers receive the market clearing price, producers will tend to bid their generation at its marginal cost. The variable costs of the last generation facility dispatched will determine price, rather than sunk investment costs. In such a system, competition is fostered through the activities of each generator, acting in its own self-interest, which together produce electricity at the lowest possible cost. PP&L St. 7, pp. 5-6.

It is to be noted that every generating unit operating in a given hour will receive the price paid for energy from the marginal or highest cost unit dispatched. In this way, all units which run in a given hour and have costs less than the marginal cost unit will receive a price which exceeds the variable costs of running such units. Accordingly, these units will recover a portion of their fixed costs.

The price of energy on an hourly basis is converted to hourly and annual revenues for each generating unit. The excess, if any, of revenues over variable costs is available to cover the fixed costs, including return, of such generation stations. To the extent that market prices are not sufficient to produce revenues to cover all fixed costs, there are stranded investments in generation.

While the theoretical approach to the models used by each witness is essentially the same, there are differences in the way that each model operates which create differences in the resulting market prices that are not accounted for by differing input assumptions. As explained in the following section of this Brief, the models employed by OCA, and particularly by PPLICA, are flawed and do not produce reliable results. Thereafter, the errors of OCA's and PPLICA's input assumptions, which are even more significant, will be explained.

a) PP&L's EGEAS Model Produces the Most Realistic and Reliable Results

Each of the witnesses testifying as to energy prices used a different model to project such prices. Dr. Jones, testifying for PP&L, used the EGEAS (Economic Generation Expansion Analysis System) model. Dr. Jones explained how the EGEAS model operates:

> EGEAS is an economic dispatch model designed primarily for long-term system planning. As its name implies, the primary purpose of the model is to find the best possible combination of generation resources for meeting system load in the short run and in the long run. In the short run, EGEAS is a production cost model, dispatching units to meet demand levels in each hour of the

> year. Over the long run, the model adds capacity to the existing system to meet reliability constraints. Depending upon the economics at that point in time a new unit will be added, either peaking or combined-cycle technology is added to minimize cost. PP&L St. 7, p. 25.

As noted in the above testimony, EGEAS determines the optimum mix of generation for each hourly load and, thereby, identifies the marginal cost unit. The cost of operating this unit determines the hourly market energy price.

It is noted that the EGEAS model has been used to dispatch units on the PJM system. It is not, therefore, a theoretical model but one which has been tested in the real world environment. Tr. 1685-86 (8/26/97). Furthermore, the EGEAS model is a publicly available model which can be acquired, used and tested by any party. PP&L St. 20-R, pp. 19-21.

In stark contrast, the model employed by PPLICA witness Mr. Falkenberg is a theoretical model and is proprietary to his firm. It was not made available to PP&L until one week after PP&L's rebuttal testimony was filed in this proceeding. Tr. 1676 (8/26/97). Nevertheless, despite limited access, PP&L's witness Mr. Falk identified serious deficiencies in the model. The numerous deficiencies in the Falkenberg model are explained in Mr. Falk's testimony. PP&L St. 20-R. However, the problem that is common to all of the defects was explained by Mr. Falk as follows:

> The entire raison d'etre for competitive markets is their ability to minimize costs to meet a given level of demand. . . Whenever a production costs simulation produces costs higher then those which are optimal, the result is to overstate what an efficient competitive market could have produced. PP&L St. No. 20-R, p. 7.
>
> ***
>
> Mr. Falkenberg has cut many corners in his model. These cut corners generally produce results, as I shall demonstrate, which do not minimize costs to meet a given load. As a result, they produce

> higher aggregate prices than a competitive market would. PP&L St. 20-R, p. 8.

Mr. Falk identified five areas in which Mr. Falkenberg's model did not optimize costs. They are: 1) maintenance scheduling; 2) scheduling of capacity additions; 3) scheduling of repowering of existing units; 4) calculation of unserved energy, and 5) size of units. Each of these areas of deficiency is addressed in detail in Mr. Falk's rebuttal testimony. These deficiencies cause Mr. Falkenberg's model to overstate market prices and understate stranded costs. On surrebuttal, Mr. Falkenberg attempted to respond to some of these criticisms of his model, but he has only reduced and not eliminated unserved demand. The other errors of his model, particularly his improper use of summer ratings year-round, continue to result in an overstatement of energy prices. *See* Tr. 1683-84 (8/26/97).

Equally, important, however, is the fact that Mr. Falkenberg's model is not tested in the real world of energy dispatch and is a proprietary model that was not made available to even the parties in this proceeding until after the filing of rebuttal. The above-referenced over simplifications and the lack of independent real world application of the model make it unreliable for the purposes for which it was submitted in this proceeding. Indeed, if the Commission were to direct use of different inputs then those which, as explained later, were erroneously employed by Mr. Falkenberg, no party other than PPLICA could run the model. Furthermore, the over simplifications noted above would have to be corrected. Accordingly, the model is simply not useful in examining the issue of forecasted market prices and the model, and Mr. Falkenberg's resulting conclusions from it must be rejected.

OCA witness D. Smith used the ENPRO model to forecast energy prices. This model is less problematic than the Falkenberg model for two reasons. First, it is an operational dispatch model like EGEAS, not a theoretical model like the Falkenberg model. Second, ENPRO is commercially available, and, therefore can be obtained and run by any participant in this proceeding. This is precisely what PP&L's witness did to test the validity of the model.

PP&L witness Dr. Jones obtained and ran the ENPRO model to determine whether the results obtained by Mr. Smith were the result of differences in the model or differences between Mr. Smith's inputs to ENPRO and Dr. Jones' inputs to EGEAS. Dr. Jones determined that there were differences in the ENPRO model and Mr. Smith's application of the model which are unrelated to differences in inputs.

The primary deficiency of the ENPRO model is that it can model only 200 units. Tr. 1398 (8/25/97). In order to provide room for the addition of new units, Mr. Smith could model less than 200 of the 350 existing units in PJM. Tr. 1398, 1511 (8/25/97).[24] To accomplish this, Mr. Smith had to aggregate existing units or treat them as one unit. Tr. 1511 (8/25/97). The problem with aggregating units, in this fashion, is that it raises energy prices by using the average cost of the aggregate group rather than the lowest cost at all times.

A second deficiency is in Mr. Smith's application of ENPRO. As explained by Dr. Jones, Mr. Smith simply assumes that units which can be fired with either oil or gas will use oil one half of the time and gas the other half of the time, regardless of competing fuel prices. This is a problem, particularly where oil prices, as in Mr. Smith's fuel price forecast, rise faster than gas prices. Of course, such assumption is unrealistic and biases electricity prices upward since duel fuel units can be presumed to use the lower price fuel. Tr. 1397-98 (8/25/97). As shown in Table D, the effect of this error alone is to overstate market value by $159.298 million.

---

[24] Mr. Smith did not indicate in his direct testimony that ENPRO requires aggregation of units. This is the type of information, however, that can be discovered by other parties when a model is commercially available. There is also no indication in that the Commission was aware of this deficiency in the ENPRO model in the PECO Restructuring proceeding.

Finally, Mr. Smith significantly reduces the availability of imports from outside PJM after 2005, without explanation or justification. Tr. 1398 (8/25/97). Because imports from the west generally are at lower costs, Tr. 1510 (8/25/97), this increases the price of electricity in PJM just as the 7-year rate cap under the Act expires. As shown in Table D, the effect of this error is to overstate market value be $226.296 million.

Dr. Jones presented Exh. STJ 33 to graphically illustrate the effects of these deficiencies in the ENPRO model. As shown by the differences between the blue and green lines on Exh. STJ 33, correction of these errors in ENPRO reduces Mr. Smith's forecasted market prices for energy by about $3/Mwh for years 2007 through 2015, with a somewhat lesser effect in earlier years. Accordingly, the errors in the ENPRO model, and Mr. Smith's application of the model, are significant. Nevertheless, these errors are mostly correctable and, if those corrections are made, the model can provide the basis for a reasonable forecast of energy prices.[25] With these corrections and the proper inputs, which will be discussed later in this Brief, the ENPRO model produces reasonable results consistent with the EGEAS model used by PP&L. As also shown on PP&L Exh. STJ 33, the remaining differences between the energy prices forecasted by Mr. Smith and those forecasted by Dr. Jones are the result of differences in inputs to the models. When Dr. Jones' inputs were put into the ENPRO model and ENPRO errors were corrected, ENPRO yields essentially the same prices as EGEAS. For this reason it is critically important that the ALJ address the appropriate inputs to the ENPRO and EGEAS models.

The EGEAS model, in contrast, does not contain the methodological problems that have been explained above with regard to the Falkenberg model and ENPRO.[26] Specifically, EGEAS

---

[25] The inability of the ENPRO model to reflect more than 200 units, however, cannot be corrected.

[26] It also is noted that no witness employed the EGEAS model in the PECO Restructuring proceeding. Since the results of such model were not available for the Commission's consideration in the PECO Restructuring proceeding, the Commission relied upon Mr. Smith's use of ENPRO. Here, the EGEAS model, which is more robust, is the best available model.

is a dispatch model which has been used for many years in dispatching units on the PJM system. As noted by Mr. Falk:

> *I've sold dispatch models commercially, and differences in* dispatch and the price and the commitment of units that would be glossed over in two seconds in a regulatory proceeding lead to weeks of meetings [and] rewrites[,] your model against my model in the real world . . . I just don't think, with all due respect to the regulatory process, that it matches the crucible of competition . . . Tr. 1685-86 (8/26/97).

The EGEAS model has been proven in the "crucible of competition". It can model all of the units in PJM as well as necessary additions, it schedules maintenance rather than spreading it arbitrarily throughout the non-summer months, it optimizes new capacity additions to produce the lowest energy costs by choosing between combustion turbine and combined cycle units, it uses appropriate prices for unserved energy and it properly reflects different summer and winter capacity ratings. PP&L St. 20-R, p. 18. It is clearly the superior model and the real world has determined that it reflects actual conditions on PJM.

b) Treatment at Start-Up and No Load Costs

The only criticism which other parties have directed at the use of the EGEAS model concerns the treatment of start up or no load costs. This is really not a criticism of the robustness of the model but, instead, its application to determine market clearing prices in this proceeding. Nevertheless, this criticism has been demonstrated by Dr. Jones as having a minimal effect on his forecasted energy prices and the resulting stranded costs of generation.

OCA witness Mr. Smith and PPLICA witness Mr. Falkenberg state that generators would not bid their incremental cost of generation because there are extra costs attributable to start-up that would not be recovered if they happen to be the unit that supplied the last kWh of energy at that point in time. In this way, intervenors argue that PP&L has understated the market clearing price of energy. OCA St. 2, p. 5. Their reasoning is that the incremental cost of some blocks of a unit is below the actual cost of operation at certain loads. Intervenors argue that the only way to account for this reluctance would be to assume that generators adjust upward their initial bids to the average cost of generation (supposing that the average costs of generation always exceeds the incremental cost of generation), because no generator would knowingly bid his incremental cost into the market for fear of losing money on an on-going basis. In the view of at least one of the intervenors, PPLICA St. 2, p. 18, the average full load heat rate would be bid by the generator assuming that the *single heat rate* for each unit was equal to the average full load heat rate.

There are two major flaws in intervenors contention about this "heat rate" issue. First, as Dr. Jones points out, PP&L St. 7-R, pp. 62-63, intervenors do not have a clear grasp of the incentives facing generators in a competitive market. Intervenors idea that no rational generator would knowingly bid his incremental cost for fear of having to forego some start-up costs incorrectly assumes that any individual generator subject to competition would somehow know, in advance and for any hour of the year, exactly when the market for energy would clear at the incremental cost of their unit. Only in this way would the potential cost of not offering capacity to the market offset the financial loss of foregoing the opportunity to earn a profit on that capacity because as long as the supply curve for energy has the usual upward slope, all generators but the last unit dispatched at any point in time will receive a price for that hour that is in excess of their incremental cost.

Second, Dr. Jones correctly notes that whether or not intervenors' allegations are valid (a) is an empirical question requiring proof and, (b) has to recognize that EGEAS does not dispatch an entire unit on the basis of a single heat rate. Rather, in a manner like the way PJM actually dispatches the system, EGEAS divides a generator's capacity into several blocks, each with a different heat rate. At some points in time, the incremental cost of energy based on heat rates is greater than <u>and</u> less than the average cost of generation as shown in PP&L Exh. STJ 22.

Dr. Jones summarized his analysis of the issue raised by other parties and his empirical test of the significance of the issue as follows.

> . . . I have tested Mr. Falkenberg's hypothesis for him. Additional runs of EGEAS using Mr. Falkenberg's suggested average heat rate approach result in higher and lower market clearing prices during the year. On balance, PP&L's estimated stranded costs fell by 0.8% or $37 million. I conclude that Mr. Falkenberg's contention that PP&L systematically understated market-clearing prices by disregarding the effect of no-load costs and average heat-rates is without merit, apparently designed to alarm the Commission rather than raise a substantive concern. PP&L St. 7-R, pp. 14-15.

As noted in the above testimony, even if generators could know in advance that their bids to supply energy would represent the market clearing price and, therefore, adjusted such bids to cover so called "no load" costs, the effect on PP&L's generation revenues would be sufficient to reduce PP&L's stranded costs by only $37 million out of $4.5 billion[27] or about eight tenths of a percent. It is not at all clear that generators will act, as Mr. Falkenberg surmises in a competitive market where they are seeking to under bid others to sell energy, and are uncertain whether their bids will set the market clearing price. However, even if <u>all</u> generators were to include such costs, which is unlikely, the effect will be to reduce PP&L's $4.5 billion of stranded costs by no more than $37 million and leave such costs still well above the $4 billion recoverable under the rate cap.

---

[27] The issue of failure to cover so called "no load" costs was one of the bases used by the Commission to reject the testimony of PECO witness Heironymus. PECO Order, pp. 85-86. However, Mr. Heironymus did not recalculate the effect on market clearing prices if generators increased their bids to include such costs, as Dr. Jones did, but instead simply assumed there would be uplift payments to generators which would not affect the market clearing price. PECO Order, pp. 85-86.

For all the foregoing reasons, PP&L has demonstrated that the EGEAS model is the most realistic and robust model for determining energy prices and should be used to determine such prices in this proceeding.

2. Inputs to Models

As explained previously in this Brief, the selection of an appropriate model is an important first step in forecasting energy prices. However, either the EGEAS model or the ENPRO model, with certain corrections, can be used to forecast energy prices. The correct inputs to the model are, by far, the most critical issues in forecasting energy prices and differences in the inputs selected by each witness account for the majority of the differences between the forecasts of the witnesses. This is illustrated by Dr. Jones' rejoinder Exh. STJ 33, which compares the results of OCA's inputs to the ENPRO model with PP&L's inputs to the EGEAS model. The difference between the green and black lines on this exhibit shows the substantial effect of OCA's and PP&L's differing inputs on the resulting forecasted energy prices. As shown by the lesser differences between the black and red lines, when the methodological errors of ENPRO are corrected and PP&L's inputs are used in both the EGEAS and ENPRO models, the differences in forecasted energy prices are not significant.

It is, therefore, very important that the Commission carefully review the inputs that have been selected by the witnesses. As explained in more detail below, OCA's and PPLICA's witnesses have used forecasts of fuel prices and inflation -- the two most critical inputs -- which are prepared by entities that have consistently overstated such variables in the past. The Commission must select inputs which are supported by common sense and by the evidence. For the reasons explained below, PP&L's inputs to the EGEAS model are reasonable and, in some instances, may even result in an overstatement of energy prices and an understatement of stranded costs.

a) Fuel Prices

(1) Projected Oil and Gas Prices

Perhaps the most critical and significant input to the models is the cost of fuel to operate each unit that generates electricity. Since the energy price for all units running in a given hour equals the cost of operating the marginal cost unit operating in that hour, the variable cost of operating the marginal cost unit is critical. Fuel price is the primary component of variable cost.

As explained by Dr. Jones, a forecast of fuel prices must reflect the fundamentals of fuel markets. In particular, two concepts are extremely important. The first concept is that increases in fuel prices should be separated into two components: increases in real fuel prices (exclusive of inflation) and increases in fuel prices due to inflation. The combination of the increase in the real fuel price and the effect of inflation on the fuel price produces the nominal fuel price at any point in time.

The second concept is that projected increases in one fuel price, such as natural gas, must be reviewed in the context of competing fuels such as oil and coal. Both common sense and experience demonstrate that prices of competing fuels move in tandem and forecasts which project different rates of increase for competing fuels are highly suspect. Application of these fundamental concepts to the fuel price forecasts of each of the witnesses demonstrates that Dr. Jones' forecast is, by far, the most reliable and most reasonable forecast.

Dr. Jones forecasted that 1996 real fuel prices would remain flat until 1999. Dr. Jones then forecasted that real fuel prices would remain flat and that nominal fuel prices would increase with inflation from 1999 forward. PP&L St. 7-R, p. 41.[28]

---

[28] Fuel prices peaked in 1996 and began to decline in 1997. PP&L St. 7-R, p. 43. Therefore, the subsequent experience tends to confirm that Dr. Jones' use of the 1996 nominal prices as the starting point for 1999 is appropriate.

Dr. Jones projected that real fuel prices would remain flat after 1999 because history *demonstrates that real fuel prices rise and fall but revert to a mean price of about $15.50 in 1996* dollars over the long term. PP&L St. 7-R, p. 47. As shown in Dr. Jones' Exh. No. STJ 16, oil prices averaged about $15.50 a barrel (in 1996 dollars) over the period 1900 to 1996 excluding the unusual period of 1979 to 1985 represented by the Iranian Revolution. It is noted, however, that other disturbances like the Gulf War are included in the experience period. Nevertheless, Dr. Jones adopted a real oil price of $18.00 per barrel, Exh. No. STJ 16, which corresponds to the average price of $17.90/Bbl over the last 10 years. PP&L St. 7-R, p. 54.

Only Mr. Knecht, on behalf of OSBA,[29] attempted to refute Dr. Jones' explanation that real prices are mean reverting, by calculating a .8% rate of increase in the price of oil from 1939 to 1996. OSBA St. 51, pp. 17-22; OSBA Exh. RDK-S-2. However, Dr. Jones explained in rejoinder that the choice of a particular starting year substantially effects this type of calculation. If Mr. Knecht had chosen any of 24 differing starting points since 1900 there would have been real declines in oil prices and, if many other starting years were used, real oil prices would simply be flat. Tr. 1404-05 (8/25/97). As a result, simply choosing a starting point year near the end of a depression when oil prices were low proves nothing about the long term trend of real oil prices.

Finally, Dr. Jones explained that projections of rising real fuel prices are contrary to both the weight of historic evidence and the progress of technological developments in exploration for fuels.

> Q. Are Mr. Knecht's conclusions then in error in concluding that real fuel prices will increase?

---

29 Mr. Knecht did not forecast energy prices in this proceeding.

> A. Real fuel prices, there's absolutely no evidence that real fuel prices will increase over the long term. In fact, it's the very progress that energy companies have made with regard to technology innovation when it comes to locating and producing energy that suggests that technical progress will continue to overcome the apparent assumption that seems to drive forecasts like those used by Mr. Smith and Mr. Falkenberg.
>
> Their forecasts rely on the assumption that technology is losing ground to the idea that energy is a finite resource and there is only so much oil and gas and uranium in the ground, so prices must rise.
>
> Professor Morris Adelman, MIT's best known natural resource economist, addressed that issue head on in his book, "The Economics of Petroleum Supply."
>
> Professor Adelman states in Chapter 13 under a heading called, "Prices Should Rise and Do Not," he says, "The assumption of an initial fixed mineral stock is not only wrong but superfluous. All else being equal, the replacement cost of any mineral should constantly increase over time and the price with it, yet prices of minerals have not risen.
>
> Practically all have been flat or actually declining in the long run. The argument now among econometricians is whether we must reject or accept a long-term downward trend for minerals prices. Long-term increases is not even in question. All else has not been equal.
>
> Mineral depletion is in fact an endless tug of war, diminishing returns versus increasing knowledge, and so far the human race has won big. Tr. 1405-06 (8/25/97).

The evidence, therefore, supports only a conclusion of flat real fuel prices.

Messrs. Falkenberg (PPLICA) and Smith (OCA) rely on the forecasts prepared by DRI and EIA respectively. By increasing nominal fuel prices more than their projected increases in inflation, these forecasts effectively project both increases in real fuel prices and increases in fuel prices due to inflation. PP&L St. 7-R, p. 55; Tr. 1404 (8/25/97). Yet neither witness has presented any substantive basis for concluding that real fuel prices will rise. In this regard, it is to be noted that Dr. Jones real oil price of $18.00/Bbl is essentially equal to the $17.90/Bbl average price over the last 10 years and is significantly above the $15.50/Bbl average long-term price of oil in 1996 dollars excluding years affected by the Iranian Revolution. PP&L St. No. 7-R, p. 54. Accordingly, Dr. Jones' projection of real oil prices is on the high side of average historical prices. Furthermore, as shown on PP&L Exh. STJ 18, one standard deviation around this average price establishes a range of $12/Bbl to $19/Bbl. While oil prices may rise and fall above the average it is reasonable to conclude that they only rarely will move outside one standard deviation. As also shown on Exh. STJ 18, in contrast to Dr. Jones' real oil price of $18/Bbl, Mr. Falkenberg's (EIA's) real oil prices begins at about $19/Bbl and continually rises throughout the forecast period to prices of about $24/Bbl, well outside one standard deviation from the average price. The DRI forecast used by OCA produces similar results. PP&L Exh. STJ 19. Accordingly, the expectation of these forecasts -- that real oil prices will rise -- is simply not supportable given historic trends. Equally important, neither OCA's nor PPLICA's witnesses has presented any evidence to support such real price rises, they have simply accepted the DRI and EIA forecasts.

The witnesses' use of the DRI and EIA fuel prices is difficult to explain given that both entities have continually over-estimated fuel prices. As shown on PP&L Exhs. STJ 14a and 14b, each of EIA's 1986, 1987, 1989 and 1992 long term fuel price forecasts has consistently overstated fuel prices. DRI's fuel price forecasts closely matches EIA's over-estimates. PP&L Exh. STJ 19. As shown on PP&L Exh. STJ 35, DRI's 1994 and 1995 forecasts also overstated inflation and, thereby fuel prices. Dr. Jones explained that the EIA and DRI fuel price forecasts are based upon macro economic models which forecast ever increasing growth without recession. This creates an upward bias to both real fuel prices and inflation. Further, these forecasts assume increased energy demand without technological innovation. PP&L St. 7-R, pp.

57-58. Regardless of the reason, the record demonstrates that these forecasts have consistently overstated fuel prices and are proven to be unreliable to forecast fuel prices and, ultimately, energy prices in this proceeding.

As noted above, the projection of fuel prices is affected by both the projection of real fuel price change, if any, and changes in fuel prices due to inflation.

As explained more completely in the inflation section of this brief, Dr. Jones projected a constant inflation rate of 2.5% and applied that inflation rate to fuel prices commencing in 1999. OCA witness Mr. Smith did not separately project real fuel prices and the effect of inflation on such prices. Instead, Mr. Smith simply adopted the DRI 1996 forecast of fuel prices.

As shown in PP&L Exh. STJ 21, the DRI 96 forecast begins with average inflation rates of 2.3% for 1997-2000, but then increases inflation rates to a level of 3.5%, on average, for the period 2005-2015. OCA's Mr. Smith revised his forecast to reflect the updated DRI Spring 1997 Outlook, Tr. 1516-17 (8/25/97), and to correct a "starting point" problem Dr. Jones noted in his testimony. PP&L Exh. STJ 12. Even so, the updated Spring 1997 Outlook continues to use the much higher 3.5% average annual inflation rate for the period 2005-2010.

Mr. Falkenberg used the EIA forecast for 1997. As also shown in Exhibit STJ 21, the EIA forecast starts with inflation at 2.5% and raises it to 3.4 % on average for 2005-2010 and 3.6% on average for the period 2010-2015. As shown on PP&L Exh. STJ 35, DRI has consistently over-estimated inflation in past forecasts. EIA forecasts match DRI's forecasts closely. PP&L Exh. STJ 19.[30]

---

30 Although EIA reduced its short term fuel forecast downward, Mr. Falkenberg made no adjustment to reflect lower fuel prices. Tr. 1751-52 (8/25/97).

Neither Mr. Smith nor Mr. Falkenberg has offered any explanation why the inflation rates built into the DRI and EIA fuel forecasts escalate over time. Tr. 1403 (8/25/97). These inflation forecasts are from the DRI and EIA fuel price forecasts. Despite reliance on these forecasts neither witness even obtained the full source documents for these forecasts or analyzed the bases used in these forecasts to estimate inflation. Tr. 1517-18, 1750 (8/25/97). Accordingly, they have not examined the bases for these forecasts and have blindly accepted them as reasonable. As explained by Dr. Jones, forecasts of inflation which rise over time are simply inconsistent with federal reserve policies observed over the last decade. Tr. 1400 (8/25/97). These witnesses have provided no bases to justify the use of the EIA and DRI inflation estimates and the record demonstrates that their forecasts have consistently overstated inflation.

The rising rates of inflation combined with rising real oil prices projected by these parties create what Dr. Jones referred to as the "dog leg" problem. The DRI and EIA forecasts initially project gradual rises in fuel prices but as the higher inflation rates and increases in real fuel prices "kick in," nominal fuel prices rise sharply. As shown graphically in PP&L Exhs. STJ 14a and 14b, the fuel price curve slopes upward in the shape of a dog leg. As explained by Dr. Jones there is no precedent in history for such an effect, PP&L St. No. 7-R, p. 42, and, in past forecasts, this phenomenon accounts, in part, for DRI's and EIA's confirmed over-forecast of fuel prices. PP&L Exhs. STJ 14a and 14b.

In PECO's Restructuring proceeding, OCA witness Smith as well as the three PECO witnesses relied in their final testimony on the Spring 1997 DRI forecast (Revised DRI)[31] and

---

[31] PECO witnesses Heironymus and Bustard used the 1996 DRI forecast initially and updated to the Spring 1997 DRI forecast. PECO witness Venkateshivara initially used his firm's ICF forecast but was replaced by witness Rose who used the Spring 1997 DRI forecast. *PECO* Order, p. 87. The Commission found troublesome these forecast changes. *PECO* Order, p. 87. Dr. Jones did not change his fuel price forecast in this proceeding. OCA witness Mr. Smith changed from the Fall 1996 DRI forecast to the Spring 1997 DRI forecast. OCA St. 2-S, p. 2.

witness Falkenberg relied, as he did here, on the EIA forecast. As a result, the reasonableness of the Revised DRI forecast and the EIA forecast were not at issue in the PECO Restructuring proceeding. As explained above, the weight of the evidence in <u>this</u> proceeding is that these forecasts are unreliable. Accordingly, the record in <u>this</u> proceeding compels rejection of such forecasts.

(2) Relationship of Fossil Fuel Prices - The Divergence Issue

There is yet another significant problem with use of DRI and EIA fuel price forecasts in this proceeding. In addition to the errors of improperly rising real fuel prices and increasing inflation rates, these forecasts project a divergence between the real prices of oil and gas versus the real price of coal. This is illustrated graphically on Dr. Jones' PP&L Exh. STJ 10, which shows the difference in rates of escalation in gas and oil prices relative to escalation in coal prices in the DRI forecast.

The divergence of gas and oil prices from coal and uranium prices is both illogical and unprecedented for competing fuels. As demonstrated by Dr. Jones in PP&L Exh. STJ 16a, real prices of competing fuels are highly correlated over the 15 year period of 1981-1995. In other words, the prices of these fuels move up and down together. This history also makes sense. If the price of one competing fuel rose sharply and others did not move upward, there would be fuel switching in many applications. PP&L St. 7-R, pp. 47-49. This is particularly the case for gas and oil versus coal. As also shown in PP&L Exh. STJ-16a, Dr. Jones's forecasts of the prices of each type of fuel are highly correlated. On the other hand, the fuel price projections of DRI and EIA show a significant, and historically unprecedented, divergence of oil and gas prices from the price of coal.

The "divergence" problem is particularly critical to the issues of stranded costs in this proceeding. The marginal cost units operating on PJM will normally be gas and oil fuel units, and these units will set the price for all units operating in the same hour. OCA and PPLICA understate the costs of operating PP&L's coal generating units by assuming coal prices that are inconsistent with oil and gas prices used in their models. The result is an understatement of stranded costs associated with these units.

The divergence of coal prices and oil and gas prices was not an issue in the PECO Restructuring proceeding for several reasons. First, as noted previously, all parties in that proceeding employed either the Spring 1997 DRI forecast or the EIA forecast. Accordingly, no party in the PECO proceeding challenged the divergence of oil and gas prices versus coal prices. Second, PECO's coal fired generating plants account for a relatively small portion of PECO's generation. *See* PECO Exh. 2, Sched. G-7, App. A-25, at R-00973953. In stark contrast, PP&L's coal fired generating plants account for 38% of its generation. *See* PP&L Hrg. Exh. 2, Filing Requirement RP-G.6, Attach. 2. Accordingly, the historically unprecedented divergence of coal prices from oil and gas prices predicted by DRI and EIA has a disparate effect on the calculation of PP&L's stranded costs as compared to PECO.

To illustrate the effect, PP&L provides the following table which compares coal prices contained in the Spring 1997 DRI forecast with coal prices escalated after 2000 at the same rate as used by DRI to escalate gas prices in such forecast.

Nominal Fuel Prices (cents/mmBTU) Based on Spring DRI Forecast

Year	Coal - DRI	Gas - DRI	Ratio*	Coal - Revised	Difference
1999	151.8	232.5	1.000	151.8	0%
2000	156.9	236.4	1.000	156.9	0%
2001	160.3	251.2	1.040	166.7	4%
2002	163.7	264.1	1.071	175.3	7%
2003	166.2	274.4	1.096	182.1	10%
2004	170.4	284.6	1.109	188.9	11%
2005	172.2	295.3	1.138	196.0	14%
2006	175.6	307.0	1.160	203.8	16%
2007	179.0	321.8	1.193	213.6	19%
2008	182.5	337.5	1.227	224.0	23%
2009	186.1	354.1	1.263	235.0	26%
2010	191.2	372.7	1.294	247.4	29%
2011	191.7	390.6	1.352	259.2	35%
2012	196.9	407.7	1.374	270.6	37%
2013	202.2	430.6	1.413	285.8	41%
2014	207.6	452.9	1.448	300.6	45%
2015	213.3	478.2	1.488	317.4	49%

(Coal Escalated at Natural Gas Rate after 2000)

*Relative rate of escalation of DRI natural gas prices applied to coal prices after 2000.

As illustrated by this table, the coal prices paid to operate PP&L's coal-fired generating plants, would be significantly higher if coal prices are escalated at the same rates assumed by DRI for gas prices. Therefore, even if the DRI gas and oil prices were accepted, despite all of the evidence in this proceeding that they are overstated, the Commission must, *at a minimum*, adjust upward the coal prices assumed by DRI. To do otherwise is not only contrary to the record but would punish PP&L for owning and operating coal plants that have produced low cost electricity for many years.

In order to further illustrate the effect of correcting the divergence of oil and gas prices from coal prices on PP&L in light of the PECO Order, PP&L has submitted a recalculation of its stranded costs which, among other things, uses prices for coal that escalate in a manner that is consistent with DRI's escalation of oil and gas prices. Correction of this divergence problem alone would create an increase in stranded costs of $230.157 million. See Table D. PP&L emphasizes, however, that, for reasons explained hereinbefore and not addressed in the PECO proceeding, the use of the DRI forecast substantially overstates all fuel prices and results in both an overstatement of future market prices for all types of generation and a gross understatement of PP&L's reasonably projected stranded costs.

For all the reasons noted above, the DRI and EIA fuel price forecasts are overstated. These overstated fuel prices result in a significant overstatement of energy prices forecasted in Mr. Smith's (OCA) ENPRO model and Mr. Falkenberg's (PPLICA) model. The Commission should reject these fuel price forecasts as unreliable inputs to any model and direct use of fuel price forecasts developed by Dr. Jones. The effect of the different fuel price forecasts pervades the market price analysis and is difficult to isolate. The parties differ in both their forecast of real price changes and inflation. The total effect of the different inflation assumptions is $198.563 million as shown on Table D. This includes both effects of inflation on fuel and non-fuel costs and the effect on inflation on market prices. The real price differences show up primarily on the "Coal Price" adjustment in the table above, which shows the effect of using OCA's higher price forecast and a higher coal price forecast as explained in Section IV C.2.a.ii, *supra*.

b) Inflation

The forecast of inflation is significant both as it affects fuel prices, as explained in the previous section of this Brief, but also because inflation is used to escalate other costs that are used in each of the models to derive market prices of electricity. In particular, variable O&M

costs must be projected for each of the units that will be operated. Each of the witnesses applies an expected inflation rate to current levels of variable O&M costs to derive future O&M costs.

There are two issues with regard to the projection of inflation. The first is what measure of inflation should be used. The second is the year by year amount of inflation.

With regard to the proper measure of inflation, Dr. Jones explained that the Consumer Price Index (CPI) is clearly overstated as to costs faced by PP&L because it relates to consumer products and not to items that affect PP&L's generating costs. While the Gross Domestic Product (GDP) deflator is a better indicator of the effect of inflation on such costs, this measure includes long-lived assets as if they were purchased monthly. Dr. Jones, therefore, concluded that the Producer Price Index (PPI), which measures prices received by industrial firms for goods they produce is the best indicator of costs to be incurred by PP&L. PP&L St. 7-R, pp. 60-61. Noting that long-term forecasts of the PPI, even by DRI, averaged less than 2.5% per year, Dr. Jones estimated average future inflation at 2.5%. PP&L St. 7, p. 40; PP&L St. 7-R, p. 61.

OCA's and PPLICA's witnesses did not evaluate the proper measure of inflation or attempt to estimate inflation. As explained previously in conjunction with fuel price projections, OCA and PPLICA simply adopted the rising inflation rates contained in the DRI and EIA forecasts. Tr. 1401-02 (8/25/97). OCA and PPLICA cannot explain the basis for these increasing inflation estimates because they blindly accepted the numbers in the fuel price forecasts. Dr. Jones explained the unreasonableness of the continually rising inflation scenario as follows:

> [F]or inflation to be sustained at an increasing rate over time, which is the assumption embedded in the intervenors' forecasts, it has to be the federal government with the cooperation of the Federal Reserve Board that has embarked on an expansionary policy supported by increases in the money supply.

This is absolutely opposite from the policies and the Fed activity that has been going on since the Reagan years. My estimate for inflation reflects a continuation of that current policy. Hence, I set inflation at its long-term trend of 2.5 percent and held it there. I have no evidence that anything to the contrary will prevail.

Q. Have other forecasters made similar projections?

A. The Federal Reserve Bank of Philadelphia released its survey of professional forecasters just earlier this month, showing that the expected change in the GNP deflator, which is a measure of overall inflation in the economy that was adopted by Mr. Falkenberg and Mr. Smith for this proceeding, would grow at 2.3 to 2.5 percent over the next two years.

This same group of forecasters expects the Consumer Price Index, which as I'm sure you're familiar with is a measure of inflation based on consumer goods, they expect the CPI to grow 2.7 percent over the next ten years.

Now, I'd like to point out that historically the difference between the CPI and the GNP deflator has been about minus 4/10th percent, suggesting that the forecasters would set a ten year outlook for the GNP deflator below my 2.5 percent inflation rate.

On top of that, I would add that what is important is what people think or expect inflation to do over the long term.

As you can see from Exhibit STJ-34 which I passed out earlier this morning, and that I actually have had blown up for purposes of this proceeding today, that the inflation fears of Americans have been fading rapidly since the start of this decade and are now well below 3 percent.

And Alan Blinder, who [was] vice chairman of the Fed during the period when a lot of this activity to reduce inflation was going on, has been quoted as saying, "When I

> was on the Fed, we said our goal was to cap inflation at 3 percent and then bring it down. Now, that view is being taken as much too pessimistic. Tr. 1400-01 (8/25/97).

For all of the foregoing reasons, including those explained in the fuel price section of this brief, OCA's and PPLICA's "adoption" of DRI's and EIA's unexplained rising inflation scenario should be rejected. A steady 2.5% inflation rate is consistent with current experience and modern monetary policy. As shown in Table D, the use of OCA's higher inflation rate increases market value by $198.583 million.

c) Load Growth and Electricity Demand

PP&L forecasted electricity demand for PJM by adopting the most recent forecast of demand compiled by PJM. Updates for demand on PP&L's system through December 1996 were reflected. PP&L St. 7, p. 44. PP&L estimated demand growth of about 1.5% annually. No party has raised any issue with regard to forecasted demand.

d) Efficiency of New Capacity

Efficiency of new capacity is principally an issue with regard to the development of capacity prices and whether capacity prices, in combination with energy prices, are sufficient to provide a return that will support the addition of new units when they are needed. As explained previously with regard to capacity prices, Dr. Jones' projected market prices for capacity and energy are sufficient to support installation of new units.

The efficiency of new units also effects energy prices. In the EGEAS model, Dr. Jones made a very conservative estimate of the fuel consumption of new combined cycle and combustion turbine units. He assumed that a combined cycle unit would require 7000 BTUs of energy to produce a kWh and that a combustion turbine would require 10,200 BTUs to produce a kWh. PP&L Exh. STJ 5. These assumptions are conservative. For example, many existing combined cycle units already can produce one kWh at lower BTU levels (i.e. lower heat rates).

PP&L Exh. STJ 28R. Reflection of these lower actual heat rates in EGEAS would have resulted in lower energy prices and higher stranded costs because it would take less fuel to produce each kWh of energy from new units. For this reason, no party has challenged the reasonableness of the efficiency assumptions used in EGEAS to project energy prices. Tr. 1392 (8/25/97).[32]

e) Other Inputs

There are several other inputs to the energy price models which, while less critical than the inputs explained above, have a relatively significant effect on the resulting energy prices produced by the models. These inputs are explained briefly.

(1) Nuclear Capacity Factor

Nuclear capacity factor refers to the percentage of the time that base load nuclear units will be operating. The use of a nuclear capacity factor that is too low in the models raises marginal energy prices by requiring other units with higher variable costs to operate. If actual nuclear capacity factors turn out to be higher than reflected in the models, actual energy costs will be lower than projected by the models.

Dr. Jones employed a forecasted 78% nuclear capacity factor in the EGEAS model based upon a study of actual unit availability factors in PJM and other systems. PP&L St. 7, p. 30. The data used to calculate availability is provided in PP&L Exh. STJ 6. Mr. Smith, without any support or explanation, "assumed . . . a 75% annual capacity factor . . ." OCA St. 2, p. 21.[33]

---

[32] As explained previously, several parties initially argued that Dr. Jones' forecasted energy and capacity prices were not sufficient to provide a return adequate to encourage installation of new units. As also explained previously, in determining whether Dr. Jones' prices will be sufficient to support new units it is necessary to consider the cost of new units and heat rates of such units when they will be installed in the future. Since Dr. Jones' capacity and energy prices are already sufficient to support a unit at today's unit costs and heat rates and those costs and heat rates likely will decline with technological progress, there is no doubt that Dr. Jones' electricity prices are sufficient to support new additions.

[33] In the PECO Restructuring proceeding, both PECO and OCA used a 75% nuclear capacity

Dr. Jones explained in rebuttal testimony that the availability of nuclear units has been steadily increasing and is projected to increase further:

> Nuclear unit availability of 78 percent is conservative. Nuclear unit availability has improved considerably in the United States in the last 10-15 years and is expected to continue to improve. Exhibit STJ-30 shows historical availability factors for nuclear units in the United States from 1982 to 1995. In that period, availability factor has improved steadily from about 65 percent to nearly 80 percent. Mounting experience in operating nuclear units has led to better management practices and fewer forced outages. For example, units experienced nearly 900 hours of forced outage in 1991. This number dropped to below 700 hours in 1995.
>
> Moreover, NERC forecasts show that this trend is expected to continue. Exhibit STJ-30 plots forecasted capacity factors to 2006 (actual capacity data are shown from 1991 to 1996). Because nuclear units are typically run at full load whenever they are available, anticipated capacity factors should closely mirror, though by slightly lower than, anticipated availability. NERC forecasts suggest availability factors of at least 85 percent should be expected for the next decade. Thus, 78 percent is a somewhat conservative estimate of future nuclear availability. PP&L St. 7-R, pp. 106-107.

Mr. Smith did not respond, in surrebuttal testimony, to Dr. Jones above quoted explanation. Mr. Smith has not provided any basis to employ a 75% nuclear capacity factor for PP&L. Accordingly, the record supports only the 78% nuclear capacity factor recommended and employed by Dr. Jones. As shown in Table D, the use of a 75% capacity factor by OCA increases market value by $46.679 million.

---

factor. As a result, use of a higher factor was not an issue in that proceeding. However, the Commission observed that PECO's actual nuclear capacity factor was <u>below</u> this level and, as a result, use of 75% was favorable to PECO. PECO Order, p. 89. In contrast, use of the industry average here would penalize PP&L and deprive <u>PP&L</u> of the benefit of its higher nuclear capacity factor.

(2) Variable O&M Costs

Another element in projecting generating costs is the variable Operation and Maintenance expenses (O&M) of each unit. Variable O&M expenses are those associated with the production of energy as contrasted with fixed O&M which are costs associated with maintaining plants ready to operate.

Dr. Jones forecasted variable O&M expenses by escalating current variable O&M costs for each plant. Dr. Jones explained that the experience in industries that have moved from regulation to competition is that O&M expenses increase, for a period of time, at rates that are less than the rate of inflation. For this reason, Dr. Jones selected escalation rates for variable O&M expenses of 2% for 1997-2000, 1.5% for 2001-2005 and 2.5% for 2006-2016. PP&L Exh. STJ 4.

Dr. Jones explained his projection as follows:

> My view of future changes in variable O&M costs, as shown in Exhibit STJ 4, stems from three sources of data. First, an examination of the trends in O&M costs in capital intensive industries beginning with the 1980's suggests that periods of competitive change often cause internal cost escalation rates in variable O&M to decline, at least in real terms. For example, a recent article on the highly-competitive (and partially regulated) oil refining industry, cited data showing O&M costs declining as much as 10-15 percent per year over the last several years[34].
>
> Second, the recent restructuring that has taken place in the natural gas pipeline industry caused variable O&M costs to trail inflation.

---

[34] Anne Rhodes, "Hostile Operating Climate Augurs Further Closures for U.S. Refiners," *Journal*, March 10, 1997, 21-23.

> Following FERC Order No. 636, pipeline company restructuring produced firms that were encouraged to respond to competitive pressures, and firms that encouraged the introduction of cost-saving technology. Third, evidence and opinion from various industry and academic publications suggest that variable O&M costs in parts of the industry may by rising slower than inflation for some time. PP&L St. 7, p. 41-42.

OCA's and PPLICA's witnesses simply applied the inflation forecasts contained in the DRI and EIA fuel price forecasts to current levels of variable O&M costs. There are two problems with this approach. First, as explained in detail in the fuel price and inflation sections of this brief, DRI and EIA have consistently overestimated inflation. OCA's and PPLICA's witnesses can provide no explanation or justification for these groups continual, and never realized, projections of rising inflation. Second, neither witness has reflected the probable effects of competition on variable O&M costs. As explained in the above quote by Dr. Jones, and as further illustrated in his rebuttal testimony, PP&L St. 7-R, pp. 22-25 and PP&L Exh. STJ 9, competition in the rail, trucking, airline and natural gas industries has produced ". . . double digit decreases in prices and costs of production . . ." PP&L St. 7-R, p. 24. The other witnesses in this proceeding simply have failed to incorporate the effects of competition in their analyses and thereby have overstated both variable O&M costs and market prices of electricity. As explained previously, variable O&M costs is just one instance of many where this deficiency is manifest.

For these reasons, Dr. Jones' projections of variable O&M costs are both reasonable and conservative in that they likely overstate costs given the proven effects of introducing competition in other industries.

(3) Reserve Requirements

Reserve requirements refer to the amount of capacity which is required above expected demand to serve unexpected contingencies such as an unplanned outage of a generating station. PJM currently plans for a 20% reserve requirement. PP&L St. 7, p. 23. However, Dr. Jones concluded that competitive pressures will lower reserve requirements to 18%. PP&L St. 7, p. 24.

Mr. Smith also assumed a going forward reserve requirement of 18% although he indicated that this might not be achieved by 2000. OCA St. 2, p. 18. PPLICA's witness did not address reserve requirements.

It is noted that reserve requirements affect energy prices by determining the timing of additions of new capacity. As new capacity is added marginal energy prices will generally decline because the new capacity is more efficient (less fuel or BTUs to produce each kWh). Thus, perhaps counterintuitively, higher reserve requirements mean lower energy prices. Therefore, Dr. Jones adoption of an 18% reserve requirement, as compared to the current 20%, increases energy prices and lowers stranded costs. If Dr. Jones had continued to employ a 20% requirement, it would have forced the model to add new efficient additions at an earlier date and energy prices would have been lowered. Accordingly, the 18% reserve requirement is conservative and again properly and consistently reflects the future effects of competition.

(4) Environmental Costs

In projecting energy prices it also is necessary to include certain environmental costs which will affect the cost of operating the marginal cost generating unit. As explained by Dr. Jones, the EGEAS model permits Dr. Jones to input costs of emission allowances as an adjustment to fuel price escalators. Dr. Jones explained how EGEAS models SO_2 emission allowance as follows:

> The first step is to identify which units will be running when the region is not in compliance. EGEAS accomplishes this by checking the emission production rate against the annual emission limit input for each facility. Once the units are identified, then those units that are subject to emissions limits are assigned allowances sufficient to bring them into compliance. The cost of bringing those units into compliance is built into the fuel escalation rates for PJM. PP&L St. 7, p. 42.

To determine the emission allowances Dr. Jones reviewed the history of SO_2 allowance prices, which have steadily declined, and he reviewed forecasts of allowance prices. Dr. Jones adopted the ICF Kaiser low case estimates of allowance prices through 2000 and escalated those allowances by the 2.5% expected inflation rate which he applied to escalate other costs. PP&L St. 7, pp. 41-42.

Dr. Jones did not include NO_x allowances as a cost in developing energy prices because of the great uncertainties in the development of technology to reduce NO_x emissions, uncertainties as to the levels of controls required for NO_x , the fact that NO_x controls are applied only in the ozone period of May through September and the lack of a developed market for NO_x allowances. PP&L St. 7, pp. 43-44; PP&L St. 7-R, pp. 97-104.

OCA witness D. Smith contended that NO_x emission allowances will increase energy prices by something less than $1/Mwh. He also argued that NO_x allowances would have a significant effect on PP&L's net revenues, but he did not quantify such effect. OCA St. 2, p. 24.

In rebuttal, Dr. Jones explained the history of declining SO_2 allowance prices and that the competitive market would similarly drive down NO_x compliance costs. Dr. Jones concluded that electricity prices would rise from about $.05/Mwh to $.30/Mwh as a result of NO_x emissions with the higher end of the range being experienced late in the transition period when NO_x standards tighten. Therefore, the combination of a minor price effect occurring late in the transition period has a very small effect due to the present value impact. PP&L St. 7-R, p. 102.

No party responded to Dr. Jones' rebuttal on NO_x emission costs. The evidence demonstrates that NO_x emission costs are not a relevant factor.

(5) NUG Output

An additional input to energy price models is the output of NUGs. While there is no dispute that the output of energy from these sources must be included in modeling energy prices, there is a dispute concerning the capacity factor at which these units will operate. Dr. Jones used a 90% capacity factor based upon actual historic experience provided by PP&L witness Mr. Krall within PP&L's service territory. PP&L St. 7-R, p. 105.[35]

OCA witness Mr. La Capra argues that PP&L has overstated NUG output by 10-15%. OCA St. 1, p. 10. However, as explained in Mr. Krall's rebuttal testimony, the NUG capacity factors used by PP&L were those actually experienced for the 3 years 1994-1996 on PP&L's system. As Mr. Krall also explained, most NUGs have now been on line for some time and early operation and start up issues have been resolved. Because there are strong incentives for high output created by payments on the basis of kWh output, these units are, and will remain, well maintained. It is, therefore, reasonable to conclude that future output levels will equal or exceed recent historic levels. PP&L St. 10-R, p. 40.

OCA has provided no reasonable basis to reject use of these actual capacity factors for NUGs. As shown in Table D, OCA's use of a lower capacity factor for NUGs understates stranded costs by $56.911 million.

(6) Revenues from Ancillary Services

Another element which was considered by Dr. Jones in forecasting the market price of energy is ancillary services. As Dr. Jones explained, the only ancillary service that affects the market price of energy is spinning reserves. Dr. Jones explained how spinning reserves were reflected in the EGEAS model:

> I specified in EGEAS a spinning reserve requirement. As a result, EGEAS ensures that sufficient spinning reserves exist for every hour. In order to meet this requirement, EGEAS adjusts its energy

---

[35] The capacity factor is relevant because, all other things being equal, higher levels of output by the NUGs will reduce energy prices by displacing the dispatch of a higher cost marginal unit.

> dispatch so that sufficient units capable of providing spinning reserves are on line. PP&L St. 7-R, p. 90.

By including the spinning reserve units as units dispatched, EGEAS includes the effects of a spinning reserve requirement in its determination of hourly energy prices.[36]

It is also noted that the revenues received from spinning reserve operators are likely to cover only the variable costs (start up and no load costs). Accordingly, such revenues will not reduce PP&L's stranded costs of generation because they will recover only variable costs and can contribute nothing toward the recovery of fixed costs. PP&L St. 7-R, p. 89.

Although there are potentially other sources of revenues from ancillary services, these revenues will not affect market clearing prices for energy. Furthermore, the amounts of these revenues are not significant. As noted by Dr. Jones, revenues derived from payments for non-spinning reserves should be very small given the large amount of capacity in PJM and the relatively small non-spinning reserve requirement. PP&L St. 7-R, p. 91. Similarly, frequency and voltage regulation will be provided at cost and would produce no contribution to fixed or stranded costs. PP&L St. 7-R, p. 92.

While other parties raised questions about ancillary services, OCA St. 2, pp. 8 and 30, Dr. Jones has demonstrated in rebuttal that the effects of ancillary services on market clearing energy prices have been properly reflected in the EGEAS model. OCA provided no response in surrebuttal. Therefore, there is no remaining issue.

---

36 To further demonstrate that the effects of including a spinning reserve requirement are reflected in the EGEAS market energy prices, Dr. Jones reran EGEAS without a spinning reserve requirement and showed that his projected energy prices would be \$.20/Mwh lower without the spinning reserve requirement. PP&L St. 7-R, p. 90.

(7) Other Inputs and Factors Affecting Energy Prices

One other issue raised by other parties concerns the effects on market clearing energy prices that would be created if there were an earlier than expected retirement of a generating plant.

Dr. Jones used projected retirement dates provided by Mr. Krall in PP&L St. 10-R. These dates reflect the retirement dates reflected in PP&L's last base-rate proceeding and are the dates reflected in PP&L's current depreciation rates. PP&L St. 7-R, p. 87.

OSBA's witness Mr. Knecht, OSBA St. 1, pp. 30-31, and OCA's witness D. Smith, OCA St. 2, p. 19, argued that economic conditions could cause earlier retirements and that early retirements would raise energy prices. Dr. Jones, however, explained the error of such unsupported contentions as follows:

> As noted earlier when demonstrating the results of OCA's requested rerun of EGEAS, new CC units will tend to displace existing fossil units. Adding efficient CC capacity in place of less efficient generation lowers, rather than raises energy prices as intervenors seem to suggest. PP&L St. 7-R, pp. 86-87.

PP&L also notes that Mr. Smith's application of ENPRO assumes that all plants will remain in service throughout the projection period. It neither reflects PP&L's projected retirements nor the proposal of OCA witness La Capra who accepted PP&L's book retirement dates, with the exception of the Keystone and Conemaugh stations.[37] OCA St.1, p. 16.

Dr. Jones' use of PP&L's current projected retirement dates as used in PP&L's last rate case is appropriate and conservative. Retirements dates of other PJM units is similarly supported. PP&L St. 7-R, p. 87. The effect of using PP&L's retirement lives in Mr. Smith's

---

[37] The effect of Mr. LaCapra's Keystone and Conemaugh life extension is addressed separately in Section V.C.10.

market price analysis and replacing the retired units with combined cycle units decreases market prices as a result of installation of more efficient units and increases stranded costs by $144.181 million as shown in Table D.

D. Conclusion

Dr. Jones' forecasted energy and capacity prices provide a consistent and reasonable basis to determine PP&L's stranded costs of generation. The record in this proceeding demonstrates that the EGEAS model is, by far, the most realistic and reliable model for projecting energy prices. While numerous issues have been raised by various parties concerning the appropriate inputs to the model, the record demonstrates that inputs selected by Dr. Jones are consistent and properly reflect expectations in a competitive market. For this reason, Dr. Jones' inputs should be accepted in their entirety.

Nevertheless, if the Commission concludes that a change to one or more of these inputs is supported by the weight of evidence, it must see to it that the remaining inputs are consistent[38] and reflect competitive conditions to be faced by PP&L.

V. REVENUE UNDER REGULATION

As explained in Section III, *supra*, PP&L determined its total stranded costs by calculating the applicable revenue requirements over the term or life of its generation-related assets or liabilities, and then compared those amounts to the estimated annual generation-related revenues that PP&L would receive in a competitive environment. The Company's stranded cost claim reflects the applicable PUC-jurisdictional revenue requirements associated with those generation-related assets and liabilities that would be recoverable from customers under

---

[38] For example, the inflation rates embedded in fuel cost escalations should match the inflation rates assigned to other inputs.

traditional rate regulation.

PP&L submitted extensive evidence in this proceeding regarding its proposed PUC-jurisdictional allocation and its generation-related revenue requirement under traditional rate regulation. The parties raised numerous objections to different aspects of the Company's filing. As explained in detail below, each of these objections is in error and should be rejected.

A. PUC Jurisdictional Allocation

In developing its PUC-jurisdictional allocation ratios, PP&L began with the cost allocation study presented in PP&L Exhibit JMK 1. That study complies fully with the Commission's Final Order in PP&L's most recent base rate case at Docket No. R-00943271, and forms the basis for existing retail customer tariff rates. PP&L St. 3-R, p. 13. The Company adjusted its PP&L's revenue requirement for known and measurable changes to PP&L's existing wholesale bulk power contracts, its contract with UGI Utilities, Inc. - Electric Division (a partial requirements wholesale customer), and its full requirements contracts with wholesale municipal customers, including Citizens' Electric Company and Allegheny Electric Cooperative, Inc. These changes include the expiration of the following bulk power contracts according to the following schedules: (1) Jersey Central Power & Light Company ("JCP&L") -- ratably over a five-year period ending December 31, 1999; (2) Atlantic City Energy Company ("ACE") -- March 20, 1998; and (3) Baltimore Gas and Electric Company ("BG&E") -- May 31, 2001. PP&L St. 3-R, p. 9. The adjusted PUC-jurisdictional allocation ratios used to determine PP&L's overall level of stranded costs are shown in PP&L Exhibit JRS 1.

OCA witness La Capra recommends that the Commission reject these changes and utilize instead, without modification, the PUC-jurisdictional allocation factors approved by the Commission in PP&L's most recent base rate proceeding. OCA St. 1, p. 9.[39] Mr. La Capra

---

[39] Similarly, Environmentalist witness Schoengold recommends that the Commission utilize a single,

argues that: (1) these changes are inconsistent with prior Commission practice; (2) the changes are "speculative"; and (3) the projected costs could be allocated to wholesale, not retail, customers.[40] These arguments are without merit and should be rejected. First, the various contract expiration dates are clearly known and measurable, and cannot be considered speculative. In fact, the one known fact is that the OCA's use of an outdated 1995 jurisdictional allocation is wrong and does not reflect actual conditions today, much less future conditions.

Second, freezing PP&L's jurisdictional allocation, as OCA and the Environmentalists propose, is internally inconsistent. On the one hand, the parties project future load growth (and thus, greater market revenues) in calculating a lower level of stranded costs for PP&L. On the other hand, however, they refuse to adjust PP&L's PUC-jurisdictional allocation factors to reflect the added capacity which would have been needed to serve such increased load if regulation had continued. The parties cannot have it both ways.

As explained by Mr. Krall, all Pennsylvania electric utilities, including PP&L, have been required to demonstrate on an annual basis that they have adequate generating resources to meet the needs of their customers over a ten-year planning horizon. PP&L St. 10-R, p. 29. As a regulated utility, if PP&L failed to meet this requirement, it would have had to obtain the necessary resources either through construction of a new generating facility or a power purchase agreement.[41] In PP&L's case, the evidence plainly demonstrates that the Company will need additional capacity to meet future load growth:

---

fixed allocation factor of 80% to determine the PUC-jurisdictional portion of each component of stranded costs. Environmentalist St. 1, p. 18.

[40] Mr. La Capra's adjustment impacts each element of stranded costs. As shown on Table D, the net effect is to reduce stranded costs by $388.415 million.

[41] PP&L must continue to meet these obligations as supplier of last resort under the Act. 66 Pa.C.S. §§ 2807(e).

> Exhibit DAK 2 is an analysis of PP&L's loads and capacity through the Winter of 2007-2008. The capacity plans in this exhibit assume no return of capacity and associated energy from the expiring wholesale contracts and no other actions to meet increasing loads. As can be seen, even if NUG capacity and interruptible loads are included as resources, reserve levels never reach even the low end of the range -- reserves would range from a high of only 13.8% in 1997 to a low of 0.8% in 2007. Clearly, some action would be required under traditional Commission practice to address this deficiency, regardless of whether the appropriate reserve margin is the 16% to 22% typical of a regulated environment or 18% as might be expected in a competitive environment. PP&L St. 10-R, pp. 30-31.

The capacity returning as a result of the aforementioned expiring power supply contracts is needed to address this deficiency and to maintain adequate reserves for reliability. Indeed, PP&L's annual resource plans filed with the Commission provide that customers' future needs will be met by generating resources that include these expiring power supply contracts. PP&L St. 10-R, p. 29. Even with this returning capacity, the evidence demonstrates that the Company's reserve levels will fall toward the low end of the Commission's acceptable range at the end of the 10-year planning period. PP&L St. 10-R, p. 32.

On this basis, the parties' proposed adjustments are completely inappropriate. The subject capacity would have been needed to meet the needs of the Company's customers in the future. It clearly is a cost "which traditionally would have been recovered under a regulated environment." 66 Pa.C.S. § 2803.

B. Cost Of Capital

Under traditional cost-of-service rate regulation, PP&L is entitled to an opportunity to earn a fair rate of return on its investment in facilities and assets dedicated to the service of the general public. Thus, in calculating the overall level of its stranded costs, PP&L appropriately included a return of and return on its unrecovered investments. The cost of capital also is relevant in determining the appropriate discount rate to be used in this proceeding. See Section VI, *infra*.

The Company determined the rate of return to be used in calculating its stranded costs based on the standards traditionally used by the Commission in determining a fair rate of return based on long-standing decisions of the U.S. Supreme Court and Pennsylvania appellate courts. See *Bluefield Waterworks and Imp. Co. v. PSC of West Virginia*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989); *Riverton Consol. Water Co. v. Pa.* P.U.C., 186 Pa. Super. 1, 140 A.2d 114 (1958); *Pittsburgh v. Pa. P.U.C.*, 182 Pa. Super. 376, 126 A.2d 777 (1956); *Lower Paxton Twp. v. Pa. P.U.C.*, 13 Pa. Cmwlth. 135, 317 A.2d 917 (1974); *Pa. P.U.C. v. Pennsylvania Gas and Water Co. - Water Division*, 19 Pa. Cmwlth. 214, 233, 341 A.2d 239 (1975).

Table E summarizes the Company's position regarding the rate of return that should be utilized to calculate stranded costs in this proceeding. The capital structure ratios and cost of long-term debt and preferred stock are the levels as of December 31, 1996, the end of the historic base period in this case. PP&L's claimed cost of common equity (11.5%) is the same as that allowed by the Commission in PP&L's 1995 base rate case at Docket No. R-00943271 (September 27, 1995).

1. Rate of Return on Common Equity

a) PP&L's Proposal

PP&L'a claimed 11.5% rate of return on common equity is both reasonable and very conservative, as shown by the independent analysis performed by Paul R. Moul, Managing Consultant of the firm of P. Moul & Associates, Inc. PP&L St. 6. Indeed, PP&L's proposed 11.5% rate of return is 125 basis points less than the 12.75% rate of return recommended by Mr. Moul. PP&L St. 6, p. 2.

The cost of common equity does not lend itself to precise mathematical calculation. The computation necessarily requires the use of overly restrictive and, in certain respects, unrealistic assumptions. Consequently, Mr. Moul did not rely solely on a single cost of equity methodology in developing his recommendation, but instead took into account the results of four well-recognized methodologies: The Discounted Cash Flow ("DCF") model, the Risk Premium analysis, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings approach. PP&L St. 6, p. 2. The use of more than one approach provides a range of results which adds reliability to Mr. Moul's analysis and better reflects the range of factors that motivate investors to commit capital to an enterprise. PP&L St. 6-R, p. 2. A detailed explanation of these four methods and their application is provided in Exhibit PRM 1 of PP&L Statement 6.

As a check on the reasonableness of his primary results, Mr. Moul also analyzed the cost of equity for a Barometer Group of eight electric companies with risk characteristics similar to those of PP&L using these four methodologies. PP&L St. 6, pp. 2-3. The cost of equity indicated by each of the four methodologies is shown below for both the Company and the Barometer Group:

	DCF	Risk Premium	CAPM	Comparable Earnings	Average of Four Methods	Midpoint of Range
PP&L Resources	11.09%	12.50%	12.44%	15.05%	12.77%	13.07%
Barometer Group	10.47%	12.50%	12.28%	15.05%	12.58%	12.76%

Based on these results, Mr. Moul determined that the appropriate cost of common equity is at least 12.75%. PP&L St. 6, p. 3. On this basis, Mr. Moul concluded that the 11.5% rate of return on common equity reflected in PP&L's Restructuring Plan filing "is below that indicated by the market models." PP&L St. 6, p. 3. Moreover, this rate of return likely will underestimate the cost of equity over the next thirty years because it is based on a 1996 base period, during which interest rates were relatively low by historical standards. PP&L St. 6, p. 4. Mr. Moul subsequently updated his analysis to reflect market data through May 1997. PP&L St. 6-R, p. 3. This analysis confirmed Mr. Moul's 12.75% cost of equity recommendation. PP&L St. 6-R, p. 3.

b) Opposing Parties' Cost Of Equity Recommendations

As explained below, the specific concerns raised by OTS witnesses Deardorff and Gruber, and OCA witness La Capra are without merit and should be rejected.

1. OTS Witness Deardorff. Mr. Deardorff's recommendations of a 10.25% cost of equity allowance, OTS St. SR-3, pp. 2, 8-10, should be rejected because it significantly understates PP&L's cost of capital. As explained by Mr. Moul, there are two ways to evaluate whether the cost of equity (and thus the overall cost of capital) will be acceptable to the financial community. The first test examines whether the cost of equity would support the Company's stock price and financial integrity. The second test determines whether the cost of capital will support PP&L's credit quality and its ability to raise capital from bond investors. PP&L St. 6-R, p. 5.

The record evidence demonstrates that Mr. Deardorff's recommendation fails to withstand scrutiny under either test. Mr. Deardorff's proposed rate of return on common equity would produce earnings per share of only $1.77, PP&L St. 6-R, p. 6, a figure lower than PP&L's earnings per share in any year since 1988 (with the exception of 1994 when several unusual occurrences artificially depressed earnings). It is also significantly below the earnings per share of $2.00 to $2.10 forecasted for PP&L by Value Line. PP&L St. 6-R, p. 6.

Similarly, Mr. Deardorff's recommendation would fail to produce an appropriate pre-tax interest coverage. Specifically, Mr. Deardorff's proposal will result in only 3.44 times pre-tax interest coverage. The Company's pre-tax interest coverage must be above the 3.5 times threshold for the A rating for an electric utility with an average business position. See PP&L St. 6-R, p. 8. Mr. Deardorff's other arguments are similarly erroneous. See PP&L St. 6-R, pp. 10-

11 (Barometer Group); PP&L St. 6-R, p. 16 (Ex-dividend adjustment); PP&L St. 6-R, pp. 17-18 (market-wide factors); PP&L St. 6-R, pp. 18-20 (CAPM and Risk Premium).[42]

In sum, Mr. Deardorff's proposed 10.25% cost of equity allowance is completely inappropriate and should be rejected. The evidence plainly demonstrates that Mr. Deardorff's recommendation significantly understates PP&L's cost of capital.

2. OTS Witness Gruber. Mr. Gruber recommends that the Commission adopt a 6.6% return on common equity in calculating the WACC. In Mr. Gruber's view, the return on common equity should be reduced to reflect his belief that "the risk faced by the Company in recovering its stranded cost is near zero . . . ." OTS St. 1, p. 10. The OTS proposed adjustment would result in a 7.25% pre-tax WACC and a 5.71% after-tax WACC, and would reduce PP&L's stranded cost claim to $3,671,499,000. OTS St. 1, p. 11. The OTS recommendation is wholly inappropriate and should be rejected for several reasons.

As a threshold matter, Mr. Gruber's 6.6% recommendation is completely at odds with Mr. Deardorff's proposed cost of equity allowance of 10.25%. PP&L respectfully submits that Mr. Gruber's proposal should be rejected on this basis alone.

Mr. Gruber confuses the cost of common equity relevant to a calculation of PP&L's

---

42 Mr. Deardorff also incorrectly contends that Mr. Moul failed to consider generation mix as a criteria in selecting companies for inclusion in his Barometer Group. OTS St. 3, pp. 33, 34. While nuclear generating capacity may indicate the need for stranded cost recovery, investment in nuclear generating capacity should not be a determinative consideration in selecting companies for inclusion in the Barometer Group. Stranded costs may be attributable to a number of sources, including fossil fuel generating assets, high cost power purchase contracts, regulatory assets and nuclear generating investments. Moreover, it is important to note that Mr. Deardorff deleted five companies from the Barometer Group he used in the PP&L's last base rate case. The deleted companies are plainly relevant to an analysis of PP&L's cost of equity. This error is compounded by the fact that Mr. Deardorff added ten new companies to his Barometer Group, seven of which previously have cut their dividends, and six of which are far too remote geographically to provide an accurate comparison.

stranded costs on the one hand, with the carrying charge applicable to the CTC and the recovery of such stranded costs on the other. The Act defines stranded costs as costs that but for competition would have been recovered in a traditional regulatory environment prior to the existence of a CTC. See 66 Pa.C.S. § 2804. Under traditional rate regulation, an accurate determination of PP&L's revenue requirement requires that, at a minimum, the WACC reflect the Company's cost of common equity. Mr. Gruber's concerns regarding the carrying charge applicable to the CTC are completely irrelevant to a determination of PP&L's revenue requirement under traditional regulation.

Mr. Gruber also is wrong in claiming that PP&L faces near zero risk in recovering its stranded costs through the CTC. The record evidence shows that PP&L in fact faces significant risk in recovering its full stranded costs. This risk is attributable to: (1) the rate cap that will limit the Company's total charges to customers during the CTC collection period; (2) the many assumptions that necessarily were used to calculate the stranded costs upon which the CTC is based; (3) the lack of any true-up under the Act of actual costs against the estimated costs used to calculate stranded costs; (4) PP&L's estimated cost of capital at December 31, 1996, which may not reflect actual capital costs during the period 1999 to 2005; and (5) the Company's use of a lower rate of return on common equity than that required by investors. PP&L St. 6-R, p. 24. Each of these factors significantly increases the risk that PP&L will not fully recover its stranded costs. PP&L St. 6-R, p. 28.[43]

Mr. Gruber also argues that future changes to the cost of capital are irrelevant to the calculation of stranded costs because that calculation looks at a specific point in time. OTS St.

---

[43] On surrebuttal, Mr. Gruber dismisses the rate cap as a relevant factor because under the OTS' proposal, PP&L "has an $800 million cushion before it would not be able to collect its allowable CTC." OTS St. SR-1, p. 3. However, Mr. Gruber conceded on cross-examination that the rate cap will prevent PP&L from recovering approximately $600 million if the adopts the Company's calculation of stranded costs. Tr. 1906 (8/28/97).

SR-1, pp. 3-4. Mr. Gruber fails to recognize, however, that future changes in PP&L's capital structure and embedded costs of debt and preferred stock could prevent the Company from recovering its full stranded costs and thus are a risk for which it must be compensated. PP&L St. 6-R, p. 27.

Finally, Mr. Gruber's proposal is flawed because it effectively prohibits PP&L from measuring its stranded costs based on full book value. Mr. Guth explained the problem with Mr. Gruber's methodology as follows:

> [I]n the regulatory method, the present discounted value of the stream of return and income tax related revenues just equals book value. This result depends on tax adjusted annual returns, on the one hand, and the discount rate on the other being the same, i.e., after-tax WACC. (See LAG 2). By reducing the first item, but not the second, Mr. Gruber -- unlike Mr. La Capra or Mr. Falkenberg -- in effect, does not permit PP&L the opportunity to measure stranded costs based on full book value, but rather on only a fraction of book value. PP&L St. 19-R, p. 26.

The effect of Mr. Gruber's proposal is shown in PP&L Exh. LAG 6. As noted in that exhibit, Mr. Gruber's risk-adjusted cost of equity results in an after-tax WACC of 5.71%, which is 72.1% of PP&L's proposed 7.92% after-tax WACC. Similarly, Mr. Gruber's risk-adjusted after-tax WACC effectively reduces PP&L's relevant book value by 26.3%, which is roughly the same percent reduction recommended by Mr. Gruber for the Company's proposed after-tax WACC. PP&L St. 19-R, p. 26. Mr. Gruber's proposal thus fails to accurately determine the full measure of PP&L's stranded costs. While the parties may argue that PP&L should not be allowed to recover all of its stranded costs, the Company submits that any debate about partial recovery should, at the very least, begin with an accurate estimate of PP&L's total stranded costs. Mr. Gruber's risk-free rate proposal fails this fundamental test and must be rejected.

3. OCA Witness La Capra. Mr. La Capra recommends that the Commission utilize a 10% rate of return on common equity in lieu of PP&L's cost of equity of 11.5% in calculating the

appropriate discount rate to be applied in this case. Mr. La Capra's recommendation is based on the 10% return on common equity approved by the Commission in PECO Energy Company's Qualified Rate Order proceeding at Docket No. R-00973877. OCA St. 1, p. 8. The effect of Mr. La Capra's proposal is to reduce the overall level of PP&L's stranded costs by approximately $106 million.

Mr. La Capra's proposal is in error for the same reasons set forth above regarding OTS' 10.25% recommendation. In addition, Mr. La Capra's recommendation is inconsistent with his use of the asset value method to calculate stranded costs. Using this method, Mr. La Capra claims to measure the market value of PP&L's generating assets to a buyer. OCA St. 1., p. 14. However, Mr. La Capra fails to consider in his analysis a buyer's own cost of capital or capital structure, both of which would significantly impact a buyer's offer to purchase PP&L's assets. As Mr. Guth explained, this flaw in Mr. La Capra's proposal is significant for two reasons:

> First, . . . market value to a potential buyer needs to take into account the discount the buyer would be able to command for giving up her option to purchase. But, in addition, the [weighted average cost of capital] of an electric utility traditionally has been atypically low compared to that of other firms in the economy operating in competitive markets. This is, of course, an intended result of regulation that has, heretofore, allowed utilities with franchise service areas the opportunity to earn a reasonable rate of return. PP&L St. 19-R, pp. 31-32.

There is simply no support for Mr. La Capra's proposal to use a lower cost of common equity in calculating the overall level of PP&L's stranded costs. Indeed, Mr. La Capra conceded on cross-examination that there is no evidentiary support for his proposal since he had not conducted a cost of equity analysis to support his recommendation. Tr. 1778-79 (8/27/97).

2. Embedded Cost Rates Of Long-Term Debt And Preferred Stock

The Company's proposed cost rates for long-term debt and preferred stock are 7.89% and 7.10%, respectively. PP&L 2, Exh. PRM 2, Schedule 1. These figures are based on PP&L's actual cost of debt and preferred stock at December 31, 1996, the end of the base year in this proceeding. These embedded cost rates are not in dispute.

C. Regulatory Assets And Liabilities

PP&L included in its calculation of stranded costs the present value (as of January 1, 1999) of its generation-related net regulatory assets.[44] The Company initially claimed $383,911,000 for such assets in its Restructuring Plan filing. PP&L Exh. JRS 1, Tab B, p. 1 of 117. PP&L subsequently revised its claim during the course of this proceeding to $354,326,000, a reduction of $29,585,000. PP&L Exh. JRS 1A, p. 1. As explained in detail below, PP&L's claim is fully supported by extensive record evidence. Several parties, however, propose adjustments to various elements of the Company's claim. The parties' recommendations are without merit and should be rejected.

1. Unrecovered Energy Costs

On December 13, 1996, the Company filed an Application with the Commission requesting permission to roll its Energy Cost Rate ("ECR") and State Tax Adjustment Surcharge ("STAS") into base rates, in response to Section 2804(4) of the Act, 66 Pa.C.S. § 2804(4), which

---

[44] The following section of this Brief addresses several issues that are not technically regulatory assets and liabilities, but have been included in the briefing outline under this heading. Several of these issues are more properly considered either under the calculation of revenue under regulation or, if the asset value methodology is adopted, under the determination of the net market value of PP&L's generation. To ensure uniformity of presentation, PP&L has followed the outline, but will identify those items that are not technically regulatory assets.

establishes price caps on the Company's rates. The Company's Application requested Commission permission to defer as a regulatory asset: (1) unrecovered energy costs as of December 31, 1996; and (2) a normalized level of estimated future on-going energy costs. On December 19, 1996, the Commission issued a Tentative Order at Docket Nos. P-00961131 and R-00963842 approving PP&L's Application ("Tentative Order"). PP&L St. 3, pp. 9-11.

The Tentative Order created two regulatory assets, both of which are reflected in the Company's Restructuring Plan filing. First, PP&L is claiming the actual undercollection of $17.2 million in energy costs as of December 31, 1996. Second, the Company seeks to include in its stranded cost calculation approximately $31.2 million of normalized, on-going future energy costs on an annual basis. PP&L St. 3, p. 11; PP&L St. 3-R, p. 19.[45]

OCA witnesses La Capra and Catlin, and PPLICA witness Kollen argue that PP&L has failed to support its claim of $31.2 million on an annual basis for future on-going energy costs. OCA St. 1, pp. 6-8; OCA St. 3, pp. 5-7; PPLICA St. 3, pp. 17-21. In fact, PP&L Exhibit JMK 5 provides a calculation of the five-year average of actual energy costs incurred by the Company during the period 1992 through 1996. This five-year average amount demonstrates that PP&L's estimated future on-going energy costs will exceed the level of energy costs rolled into base rates on January 1, 1997 as a result of the Commission's December 19, 1996 Order by approximately $31.2 million annually. PP&L Exh. JMK 5.

Based on actual energy costs for the period January 1, 1997, through June 30, 1997, the Company already has under-recovered $22.5 million of the energy costs included in its base rates. PP&L St. 3-R, pp. 19-20.[46] The Company expects to underrecover its energy costs by

---

45 PP&L originally estimated that its normalized, future on-going energy costs would equal approximately $31.5 million on an annual basis. PP&L St. 3, p. 11. The Company subsequently reduced this estimate to $31.2 million based on updated information. PP&L St. 3-R, p. 19.

46 In its Restructuring Plan proceeding, PECO claimed $22 million for annual deferred fuel expense

approximately \$36 million in 1997 and \$67 million in 1998. PP&L St. 3-R, p. 19, PP&L Exh. JMK 6.

Mr. La Capra contends that PP&L overstates its under-recovery of future on-going energy costs for the years 1997 and 1998 because the Company's claim is not based on a mills per-kilowatt-hour basis. OCA St. 1, p. 7. Mr. La Capra is completely in error. As explained by Mr. Kleha, the calculations supporting the Company's claim (Exhibits JMK 5 and 6) in fact reflect a mills per-kilowatt-hour energy cost determination. PP&L St. 3-R, pp. 20-21.

Mr. Catlin also suggests that PP&L's claimed underrecovery of on-going energy costs is overstated because PP&L is earning more than its required return on common equity. OCA St. 3, pp. 6-7. Mr. Catlin is incorrect. PP&L's pro forma rate of return on common equity was 11.42% for the year ended December 31, 1996, below the 11.50% allowed by the Commission in PP&L's most recent base rate case in 1995. PP&L St. 3-R, p. 22.[47]

PP&L notes that PECO's claim for future understated projected energy costs in its Restructuring Plan proceeding was denied by the Commission. PECO Order, p. 71; Order on Reconsideration, p. 11. Nonetheless, PP&L respectfully submits that the Commission's resolution of this issue in the PECO proceeding should not be dispositive of its claim in this case. These costs are "known and measurable" under traditional PUC practice, were deferred and properly recorded as a regulatory asset pursuant to PUC Order, and properly should be

---

through December 31, 1998, and \$22.7 million annually through December 31, 2005, to recover the amount by which its average energy costs rolled into base rates understate its estimated going-forward energy costs.

[47] The calculation and data submitted by the Company in support of its claim are similar to the information PP&L consistently provided to the Commission to support its energy cost rate filings. Tr. 1108 (8/20/97). Thus, Messrs. Kollen and Catlin are incorrect in stating that the Company failed to reflect revenues in its calculation of future under-recovered energy costs. PPLICA St. 3-S, p. 21; OCA St. 3-S, p. 4.

recoverable under the Act.

2. Employee Transition Costs And Pension Plan

The Company's claimed stranded costs reflect estimated additional severance and pension costs that PP&L expects to incur between 1997 and 2001 as a result of its projected decline in the number of employees as the Company prepares for a competitive market. PP&L St. 8, pp. 25-26. PP&L's estimated severance and pension expenses are as follows: 1997: $5,014,000 1998: $6,782,000; 1999: $4,157,000; 2000: $3,118,000; 2001: $4,211,000. PP&L Exh. JRS 1, Tab F, p. 40. The Company calculated a five-year amortization of the costs incurred in each year, and included in its calculation of stranded costs, the net present value of the recovery of these deferred costs that are allocable to the generation function ($17.106 million). PP&L St. 8, pp. 25-26.

The OCA argues that the claimed employee transition costs for 1997 and 1998 should be excluded. OCA St. 3, p. 10. This adjustment would reduce the balance of regulatory asset for employee transition costs by $10.793 million. The OCA also contends that incremental pension benefits should be excluded because such benefits will not result in added out-of-pocket costs due to the overfunded position of PP&L's pension plan. This adjustment would further reduce the regulatory asset by $8.003 million. As a result of these two adjustments, the OCA recommends that the Commission allow only $3.483 million of future on-going employee transition costs as a regulatory asset. OCA St. 3, p. 11.

Similarly, PPLICA asserts that PP&L's claimed future on-going employee transition costs are speculative, and that the Company failed to reflect normal employee attrition in its calculations. PPLICA St. 3, pp. 22-23. Even if the Commission "conceptually" adopts this regulatory asset, PPLICA argues that such asset should be valued at $5.502 million, the net present value of future cash outlays. PPLICA St. 3, p. 23.

The OCA and PPLICA adjustments are inappropriate and should be rejected. The additional severance and incremental pension costs that the Company is claiming and expects to incur are the result of PP&L's transition to a competitive market. These costs are explicitly identified in the definition of "transition or stranded costs" in Section 2802 of the Act. The cost savings attributable to the anticipated employee reductions are reflected in A&G expenses related to the generation function which are included in operation and maintenance expenses. As explained by Mr. Schadt, PP&L projected that A&G expenses will decline between 1997 and 2001 as the Company prepares for competition, rather than increase at an annual inflation rate of 2.5 percent. PP&L St. 8-R, p. 50.

PP&L also fully reflected normal employee attrition for the period 1997 through 2001 in its calculations. PP&L's actual historical rate of attrition has averaged approximately 2.5 percent. PP&L expects the rate of "normal" attrition to decline in the future due to the fact that a large number of employees already have left PP&L as a result of its restructuring initiatives. Despite this anticipated downward trend, the Company elected to utilize a more conservative forecast in calculating employee transition costs, and assumed that as many as 5 percent of the projected 381 departing employees would leave as a result of "normal" attrition. PP&L St. 8-R, pp. 51-52.

Finally, the OCA incorrectly seeks to disallow incremental pension benefit cost arguing that the Company's pension plan is currently "overfunded." These "excess" pension fund assets are the result of the accounting method utilized to track these assets (SFAS 87) and the strong performance of the stock market in recent years. PP&L St. 8-R, pp. 30-31. PP&L has already taken this strong performance into account in calculating its pension expense under SFAS 87. For example, the value of future pension benefits earned by all participants during the current year is approximately $32 million for 1997. However, the stock market's performance has produced a substantial unrecognized net gain that, as it is amortized, reduces the amount included in expenses and used to project future costs to only $5.7 million for 1997. Any additional offset to reflect "excess" plan assets as a regulatory liability, including OCA's recommended disallowance, is completely inappropriate and would "double count" the unrecognized net gains. PP&L St. 8-R, pp. 31-32. Indeed, the Commission recently refused to adopt an adjustment in the PECO Restructuring case to reflect PECO's overfunded pension plan.[48] The Commission concluded that an additional adjustment was inappropriate because PECO, like PP&L, already credited customers with the economic benefit of the overfunding by reducing its annual claimed pension expense. Order on Reconsideration, p. 14.

In a related adjustment, Mr. Kollen recommends that the Commission recognize a regulatory liability of $253.832 million at December 31, 1998 associated with the Company's alleged "excess" pension fund assets, PPLICA St. 3, pp. 14-16, arguing that it may be "utilized by the Company either to offset future pension expense or to withdraw in some manner, albeit with certain limitations and penalties."

Mr. Kollen's proposed adjustment should be rejected for the reasons discussed above. As Mr. Schadt explained:

> Mr. Kollen's pension fund adjustment amounts to trying to pay two bills with one check. Mr. Kollen would not change the pension expense reflected in the filing, the amount of which is reduced substantially by actuarial calculations that take into account, on an ongoing basis, the total value of current plan assets and projected earnings on those assets. He then, having taken advantage of the projected long-term value of those assets to reduce pension costs already reflected in the filing, recommends that the same assets be used over again to reduce regulatory assets. PP&L St. 8-R, p. 33.

---

48 In its Final Order, the Commission initially adopted a regulatory liability of $217.347 million to reflect PECO's overfunded pension plan. PECO Order, p. 76. On reconsideration, however, the Commission eliminated the regulatory liability and increased PECO's stranded costs. Order on Reconsideration, p. 14.

The evidence establishes that "the full amount of the plan's assets and obligations are already and appropriately being used to lower the amounts currently charged to ratepayers and to offset future pension expense, which lowers the Company's estimate of stranded costs." PP&L St. 8-R, p. 32. Mr. Kollen's double use of the pension "over funding" should be rejected.

3. Taxes Other Than Income

PP&L properly included Taxes Other Than Income in its calculation of stranded costs. The Company's claim includes two components: (1) capital stock taxes; and (2) Public Utility Realty Tax ("PURTA").[49] PP&L calculated the actual amount of capital stock and PURTA taxes in 1996 applicable to fossil and nuclear generation facilities. The Company then escalated the 1996 taxes at the rate of inflation (2.5 percent) over the life of each generating facility. PP&L St. 8-R, p. 35; PP&L Exh. JRS 1, pp. 4-5.

OTS, OCA and PPLICA each oppose the Company's claim. OTS and PPLICA argue that capital stock taxes should remain constant over the life of each generating facility, but that PURTA taxes should decline in relation to the decline over time in net plant balance resulting from depreciation. OTS St. 2, pp. 16-23; PPLICA St. 2, pp. 50-51. Adoption of OTS' adjustment would reduce PP&L's nuclear generation-related stranded costs by $280.7 million, and its fossil generation-related stranded costs by $66.1 million. OTS St. 2, pp. 22-23.

OCA recalculated PP&L's stranded costs assuming that Taxes Other Than Income would remain constant over the life of the Company's nuclear and fossil generating facilities reducing PP&L stranded costs by $182 million. OCA St. 1, p. 16.

The parties' proposed adjustments are inconsistent with the Act and should be rejected.

---

[49] This item is not a regulatory asset. It is a cost of operation included in the calculation of revenue under regulation in PP&L's regulatory model and as an offset to market revenue in the asset value model.

Section 2810 of the Act states that the transition to retail competition shall be revenue neutral as to the Commonwealth. 66 Pa.C.S. § 2810. To achieve this revenue neutrality, PP&L's claim reflects two assumptions. First, PP&L assumed that, similar to the Company's costs, the cost of services provided by the Commonwealth would increase with inflation. Second, PP&L assumed that the various tax revenues collected by the Commonwealth would increase proportionally to fund the higher cost of goods and services.[50] Mr. Schadt explained that "common sense would dictate that as the cost of services provided by the Commonwealth increases, tax revenues must keep pace..." It is difficult to believe that the capital stock and PURTA taxes would remain at the 1996 level over the next 20 to 30 years, let alone decrease during this period. PP&L St. 8-R, p. 37. The opposing parties' recommendation would freeze capital stock and PURTA tax revenues to the Commonwealth at 1996 levels. This recommendation is inconsistent with the revenue neutrality goal of Section 2810 of the Act and therefore should be rejected.

4. Fossil Plant Decommissioning

PP&L's calculation of stranded costs includes $315.867 million attributable to the costs of decommissioning its various fossil generating units.[51] PP&L escalated each fossil plant's decommissioning costs at a 2.5 percent annual rate of inflation to the end of its book life. The Company assumed that it would incur decommissioning costs over a three-year period -- 40 percent in the year each plant is retired, 40 percent the following year, and 20 percent the next year. PP&L Exh. JRS 1, p. 8.

---

[50] Pennsylvania historically has increased capital stock and PURTA taxes to increase its tax revenues. For example, Pennsylvania has increased the capital stock and PURTA tax rates since 1984. PP&L Exh. JRS 4. Similarly, Pennsylvania may assess a utility an additional amount of PURTA tax to make up any shortfall. Indeed, PP&L was assessed an additional amount of PURTA tax in 1994, 1995 and 1996. PP&L St. 8-R, pp. 36-37.

[51] This item is not a regulatory asset. It is an operating cost included in revenue order regulation in PP&L's regulatory model and as an offset to market revenue in the asset value model.

The OCA and PPLICA recommend that the Commission exclude the Company's claimed costs in their entirety. Generally, the parties offer four arguments. First, the OCA asserts that fossil decommissioning costs "simply do not fit the definition of stranded costs." OCA St. 1, p. 18. Second, PPLICA contends that the Company's claimed costs are speculative and unsupported. PPLICA St. 3, pp. 30-35. Third, PPLICA argues that recovery of such future costs consistently has been denied. Fourth, OCA and PPLICA contend that allowance of PP&L's claim would provide it with a competitive advantage over non-Pennsylvania utility fossil generation suppliers who must incur decommissioning costs without the prospect of recovering such expenses from customers through a CTC. OCA St. 1, p. 18; PPLICA St. 3-S, p. 31.

In its recent Order in the PECO Restructuring Plan proceeding, the Commission denied a similar claim by PECO for $126.6 million for costs associated with the decommissioning of its fossil generating facilities. The Commission concluded that PECO's claimed expenses were unsupported and speculative and are prohibited by Pennsylvania law. PECO Order, pp. 49-50. PP&L respectfully submits that the arguments relied upon by the parties in this case are in error and that the Commission must address the issue de novo in this case.

First, Section 2803 of the Act clearly defines "transition or stranded costs" as including "retirement costs attributable to the utility's existing generating plants other than the costs defined in Paragraph (1)," which refers to the recovery of nuclear generating plant decommissioning costs. 66 Pa.C.S. § 2803. Thus, fossil decommissioning costs which are incurred to retire existing fossil generating facilities are defined by the Act as allowable "transition or stranded costs" and must be included. The OCA's primary stranded cost witnesses essentially conceded the point on cross-examination.[52]

---

[52] Mr. La Capra conceded on cross-examination that, as a general matter, fossil decommissioning costs could fall within the definition of "stranded costs." Tr. 1787-88 (8/27/97).

Second, PPLICA argues that the Company's claimed costs are speculative and unsupported. Specifically, Mr. Kollen asserts that PP&L's claim derives from a fossil decommissioning study performed by TLG Services which is based on three erroneous and speculative assumptions: (1) PP&L's fossil generating facilities will be decommissioned while owned and controlled by the Company; (2) the facilities will be retired on the dates indicated in the study; and (3) the facility sites will be restored to "greenfield" conditions. PPLICA St. 3, pp. 31-32. Similarly, in denying PECO's claim for fossil decommissioning costs, the Commission concluded that there was no evidence "that any particular fossil plant will in fact have to be decommissioned at all, when such decommissioning might occur, the extent of decommissioning that will be required, the future use of the plant and its site, or the cost of the decommissioning found to be needed." See also PECO Order, p. 92.

The concerns held by PPLICA and the Commission with respect to this issue are misplaced in this case. PP&L in fact has submitted substantial evidence in this proceeding which fully supports its estimated future fossil decommissioning costs. Indeed, past industry experience suggests that PP&L's claim may be understated, as decommissioning estimates generally have proven to be much lower than the actual costs incurred. PP&L St. 3-R, p. 34. Mr. Kollen conceded on cross-examination that the TLG study is very similar to other studies relied upon by the Commission to establish allowable levels of nuclear decommissioning expense. Tr. 1486 (8/25/97). Moreover, Mr. Kollen agreed on cross-examination that the nuclear decommissioning study performed by TLG and relied upon by the Commission in PP&L's last base rate proceeding contained the same types of assumptions that Mr. Kollen now attacks in the TLG fossil decommissioning study in this proceeding. Tr. 1486-88 (8/25/97). PP&L submits that the record evidence fully supports its claimed level of fossil decommissioning expenses.

Third, Mr. Kollen and the Commission also are mistaken in asserting that the Superior Court's decision in *Penn Sheraton Hotel v. Pa. P.U.C.*, 198 Pa. Super. 618, 184 A.2d 324 (1962), prohibits recovery of projected fossil decommissioning costs. PPLICA St. 3, pp. 33-34; PECO Order, pp. 91-92. *Penn Sheraton* fully supports the recovery of fossil decommissioning costs; the only point at issue was the timing of that recovery.

Penn Sheraton prohibited advance recovery of retirement costs but permitted recovery of actual retirement costs.[53] As explained by Mr. Kleha, PP&L's estimate of stranded generation-related capital and operating expenses was calculated utilizing the revenue requirements methodology contemplated by the Act. PP&L St. 3-R, pp. 31-32. Using this methodology, the Company included in its calculation the costs of decommissioning existing fossil generating facilities that would be recoverable under traditional rate regulation at the end of the lives of those facilities. Thus, consistent with *Penn Sheraton*, PP&L's claim reflects its projected fossil decommissioning costs at the point in time when they actually would be incurred. PP&L St. 3-R, p. 32.

Fourth, the OCA's and PPLICA's competitive advantage argument is inconsistent with the Act and, in fact, would place PP&L at a competitive disadvantage. As Mr. Kleha explained, the parties:

> fail[] to recognize that the owners/operators of non-Pennsylvania utility fossil generation facilities can provide for the cost of decommissioning over the lives of their facilities. Therefore, because of the PUC's historic reliance on the *Penn-Sheraton* decision to defer the recovery of fossil decommissioning costs until the costs [are] actually incurred (cash vs. accrual accounting), Pennsylvania electric utilities are required to seek and obtain stranded cost recovery of those costs or be placed at a significant competitive disadvantage. Moreover, the failure to accrue for decommissioning costs over the lives of the fossil generating facilities which give rise to those costs is not in accordance with

---

[53] Moreover, to the extent *Penn Sheraton* is read to prevent stranded cost recovery of retirement costs it is patently inconsistent with the Act, which clearly permits recovery of these retirement costs.

> the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts, which the PUC has adopted. PP&L St. 3-R, pp. 32-33.

Finally, while OTS does not oppose PP&L's proposed stranded cost recovery of fossil decommissioning costs, Mr. Gruber recommends that the Commission require the Company to place all amounts recovered in a separate, non-qualified trust fund that would be accessible only as fossil decommissioning costs are actually incurred. OTS St. 1, p. 15. Mr. Gruber's recommendation is inappropriate, inconsistent with Section 2806(A) of the Act which provides that "the generation of electricity shall no longer be regulated as a public utility service or function" and should be rejected.

Moreover, under the Act, PP&L is required to bear all of the risk associated with the estimate of its fossil decommissioning costs, since it will recover only the net present value of PP&L's projected fossil decommissioning costs. Thus, PP&L must bear the risk that its estimate understates such costs.[54] In recognition of this substantial risk, PP&L submits that it should not be required to place the amounts collected in a separate trust fund, and instead should have such amounts available to utilize in conducting ongoing business activities. PP&L St. 3-R, pp. 34-35.[55]

5. Nuclear Plant Decommissioning

In calculating the annual revenue requirement for nuclear generation, the Company included the amount it is recovering in annual nuclear decommissioning expense through

---

54 In fact, prior experience shows that decommissioning cost estimates generally have been substantially lower than the actual costs incurred. PP&L St. 3-R, p. 34.

55 It is unclear whether Mr. Gruber's recommendation includes the segregation of recovered amounts into separate trust funds for each fossil generating facility. Any such proposal is inappropriate and contrary to the public interest because it would limit the Company's ability to allocate funds among its various fossil generating facilities as necessary during actual decommissioning activities. PP&L St. 3-R, p. 35.

existing retail and wholesale rates, adjusted to the appropriate PUC-jurisdictional amount. PP&L St. 8, p. 11.[56] Currently, PP&L is recovering approximately $9.5 million per year in jurisdictional rates for nuclear decommissioning costs. PP&L St. 3, p. 15. PP&L's stranded cost claim reflects the net present value of after-tax future annual nuclear decommissioning expense accruals over the remaining life of the Company's nuclear facilities. As a preferred alternative, however, PP&L proposes to recover its nuclear decommissioning costs over the remaining life of its nuclear generating facilities, through distribution charges on a per kWh basis. PP&L St. 3, p. 14; PP&L St. 3-R, p. 28.

Two concerns underlie PP&L's proposal. First, there is some question as to whether the transition to full competition will ensure the adequate recovery of nuclear decommissioning costs. Section 2808 of the Act, 66 Pa.C.S. § 2808, provides electric utilities "an opportunity" to recover stranded costs through the CTC, including nuclear decommissioning costs that may not be recoverable in a competitive generation market. Thus, PP&L will have to fund a substantial amount of its nuclear decommissioning costs using revenue from market rates. There is no assurance, however, that such market rates will be sufficient to satisfy PP&L's nuclear decommissioning funding obligations. PP&L St. 3, p. 12.

Second, there is a risk that the transition to full competition could subject PP&L to substantial financial qualification requirements under Nuclear Regulatory Commission ("NRC") regulations. Specifically, NRC regulations exempt "electric utilities" from the requirement to provide additional financial assurance for nuclear decommissioning (e.g., insurance or surety bond) beyond establishment of an external sinking fund. "electric utilities" are defined as "any entity that generates or distributes electricity and which recovers the cost of electricity, either

---

[56] This item is not a regulatory asset. It is an operating cost included in the calculation of revenue under regulation in PP&L's regulatory model and as an offset to market revenue in the asset value model.

directly or indirectly, through rates established by the entity itself or by a separate regulatory authority." 10 C.F.R. § 50.2

Under traditional cost-of-service rate regulation, PP&L plainly satisfies the NCR's definition of "electric utility" because its rates are set by the Commission. PP&L currently is authorized to recover its estimated future nuclear decommissioning costs in rates over the remaining life of its nuclear generating facilities, and all recovered amounts are placed in an external trust fund. However, the Act requires that all generation-related costs, including those related to PP&L's nuclear generating facilities, be removed from traditional rate regulation. The Company's proposal to recover its claimed costs through a distribution charge is designed to address both of these concerns. PP&L's proposal will ensure adequate nuclear decommissioning funding and will provide for the recovery of such costs through rates established by the Commission. PP&L St. 3, pp. 14-15.[57]

PPLICA and the Environmentalists oppose the Company's proposal. First, PPLICA contends that PP&L's proposal to recover nuclear decommissioning costs on a per kWh basis is inconsistent with its treatment of such costs in its last base rate case. PPLICA St. 1, pp. 55-56. Mr. Baron's concerns are misplaced and should be rejected. The record evidence plainly shows that the Company unbundled costs in this case using the same demand allocators utilized in its last base rate proceeding. Thus, PP&L's proposed unbundled tariff rates reflect nuclear decommissioning costs allocated among customer classes on a demand basis. The Company proposes to recover these demand-allocated costs on a per kWh basis, which is the same method currently used to recover such costs through fully regulated rates. PP&L St. 3-R, pp. 28.

---

[57] The charge that would result from PP&L's proposal would be extremely small and would have a minimal impact on customers. For example, the Company currently collects approximately $9.5 million per year in rates for nuclear decommissioning costs. For the average residential customer using 500 kWh per month, this equals approximately 0.03¢/kWh, which is approximately $0.15 per month and less than $2.00 per year.

The Environmentalists oppose PP&L's proposal to extend the CTC, and recommend that the Commission consider "the benefits of an incentive framework for nuclear decommissioning costs, in which risks are shared between the Company and its customers." Environmentalists St. 2, p. 28. This proposal is inconsistent with the Act, which clearly states that the PUC "shall" provide for recovery of nuclear decommissioning costs. 66 Pa.C.S. § 2808(c)(1). Moreover, adoption of this proposal would clearly jeopardize PP&L's NRC status as an "electric utility" and could result in a pre-funding requirement that would impose an additional burden on customers. See also PP&L St. 3-R, pp. 29-30.

Finally, it should be noted that PPLICA initially opposed the Company's proposal to recover nuclear decommissioning expenses as a distribution-related component of its delivery charges, claiming that PP&L would recover such expenses twice. PPLICA St. 3, p. 39. In rebuttal, PP&L explained that it would exclude nuclear decommissioning costs from those recovered through the CTC if the Commission adopts the Company's proposal. PP&L St. 3-R, p. 29. Based on this clarification, PPLICA agreed that PP&L's proposal would not result in the double recovery of nuclear decommissioning costs. PPLICA St. 3-S, p. 33.

The Commission already has approved a similar proposal for the recovery of nuclear decommissioning costs in the PECO case. PECO's post-1998 decommissioning costs were reflected in its calculation of stranded costs as a future operating expense affecting the market value of its facilities. With respect to its claimed underrecovered costs, PECO proposed two collection methods. PECO first suggested recovering its costs through the CTC as a stranded cost. In the alternative, PECO proposed to recover its claimed costs as an annuity through regulated transmission and distribution rates. The Commission adopted PECO's second proposal, finding that it would ensure that the amounts recovered would continue to qualify for favorable IRS and NRC treatment. PECO Order, p. 78-80.

In the instant case, PP&L's proposed distribution charge for the recovery of its estimated nuclear decommissioning costs is similar to the mechanism approved by the Commission in the PECO proceeding. As explained above, the Company's proposal will ensure that it fully recovers its nuclear decommissioning costs over the remaining life of its facilities, and that it retains its exemption from burdensome NRC financial assurance requirements. PP&L's proposal is completely consistent with the Commission's decision in the PECO case and should be adopted.

6. Department Of Energy Assessments

The Energy Policy Act of 1992 ("Energy Act") establishes an assessment on utilities, including PP&L, owning nuclear power operations to provide funds for the decontamination and decommissioning of the Department of Energy's ("DOE") uranium enrichment facilities. Under the Energy Act, this charge is assessed over a 15-year period, and is deemed a necessary and reasonable current cost of fuel that is fully recoverable in rates in the same manner as other fuel costs. PP&L St. 8, p. 24.

PP&L determined the amount of DOE assessment costs that would be recovered annually through existing rates, and included the present value of the PUC-jurisdictional portion of this amount in its calculation of stranded cost. PP&L St. 8, p. 24. The OCA and PPLICA recommend that the Commission disallow the Company's claim in its entirety, noting that PP&L already reflected this assessment in its Restructuring Plan filing as a component of fuel expense. OCA St. 3, p. 7; PPLICA St. 3, pp. 24-25. In response, the Company eliminated all DOE assessment amounts from the fuel expense component of its generation-related costs, which reduced PP&L's stranded costs by approximately $17 million. PP&L St. 8-R, pp. 56-57. This correction fully addresses the OCA's and PPLICA's concerns.[58] PP&L's proposed recovery of

---

[58] On surrebuttal, Mr. Kollen argued that PP&L failed to correct the double-counting error. PPLICA St. 3-S, p. 26. As explained by Mr. Schadt, the DOE assessment was removed from the generation-related stranded cost calculation, and was retained as a regulatory asset. Tr. 1545-46 (8/26/97). The error clearly was corrected; Mr. Kollen is mistaken.

DOE assessment costs as a regulatory asset, therefore, is appropriate and should be approved.

7. Susquehanna Deferred Refueling Expenses

PP&L's stranded cost calculation includes a claimed regulatory asset for incremental maintenance costs incurred during refueling and inspection outage at PP&L's Susquehanna Steam Electric Station ("SSES"). These costs are deferred and amortized from the end of the outage until the next scheduled refueling and inspection outage is completed. The Company determined the annual recovery that would occur through existing rates and included in its stranded cost calculation $7.996 million on a present value basis at December 31, 1998 for the PUC-jurisdictional portion of these costs. PP&L St. 8, p. 25.

OTS, OCA and PPLICA each oppose the Company's claim for deferred SSES refueling expenses. First, OTS asserts that refueling expenses are typical, ongoing costs that properly should be normalized, not deferred and amortized for future recovery and thus should be disallowed. OTS St. 2, pp. 15, 16. The OTS adjustment should be rejected because, the Company's claim is fully consistent with the manner in which PP&L historically has accounted for and recovered SSES refueling costs. As explained by Mr. Schadt, PP&L did not claim costs associated with the first refueling outage of SSES Unit 1 in its 1983 SSES Unit 1 rate filing with the Commission (Docket No. R-822169). Instead, the Company requested and received permission to defer and amortize its incremental refueling costs over the period of time from the date of restart following the outage until the date of restart after the next outage. PP&L St. 8-R, p. 46. Mr. Schadt further explained that, "[b]ecause PP&L proposed to recover these costs in a period after they were incurred, it was necessary to accumulate and defer the actual costs of the first refueling outage on the Company books and amortize this amount over the period it was to be recovered in rates" Id. PP&L has utilized this deferral method of recovery for both SSES units since 1983. The Company's claim in the instant proceeding utilizes this same deferral method and therefore should be allowed.

Second, PPLICA and OCA contend that PP&L's claimed costs are premised on a change in accounting caused by the Company's change to a 24-month refueling cycle for SSES Unit 1 in 1997 and for SSES Unit 2 in 1998. PPLICA St. 3, p. 36; OCA St. 3, p. 9. As a result of this change, PPLICA notes that SSES Units 1 and 2 will undergo refueling outages in alternate years, which will cause the Company to expense actual outage costs each year. PPLICA and OCA argue that, despite these changes, PP&L has failed to modify its accounting practices to eliminate deferrals and amortizations in 1997 and 1998, and instead "has assumed that it can defer the accounting recognition of those changes into the 'subsequent to 1999' period, although it had no accounting order from the Commission that authorized such a deferral." PPLICA St. 3, p. 37. PPLICA and OCA, therefore, recommend that the Commission disallow the Company's request.

PPLICA's and OCA's recommendation is in error and should be rejected. As noted above, PP&L was authorized to accumulate and defer the first refueling outage costs for SSES Unit 1 over the subsequent fuel cycle. Thus, PP&L always has been one cycle behind in recovering refueling outage costs. As explained by Mr. Schadt, the parties' recommendation would result in an improper matching of outage costs and revenues.

> [r]egardless of the fuel cycle length or the subsequent accounting of the deferred outage costs, the Company will still have unrecovered deferred refueling outage costs at January 1, 1999. Because the Company has always been one cycle behind in recovering outage costs, there will still be prior deferred refueling outage costs remaining after both units make the transition to the 24-month cycle. See Exhibit JRS 6. Under the existing regulatory accounting methodologies, these unrecovered prior outage costs would have remained a regulatory asset until they could be included in rates. In other words, they represent costs that would have been recovered in an ongoing regulatory environment; therefore, they are appropriately classified as a regulatory asset. If the Company expensed current outage costs as well as continued to amortize the prior outage costs, the Company would experience double outage costs without the benefit of matching revenues. The filing reflects the expense of these outage costs on a levelized basis, with the unamortized amount of outage costs at the time of

> customer choice being classified as "stranded costs". PP&L St. 8-R, pp. 48-49.

PP&L has recorded a regulatory asset for this cost for many years with PUC approval. There is no reasonable basis for disallowing this claim.

8. Earnings On Recovered SFAS 106 Costs

In its Final Order at Docket No. R-00943271, the Commission authorized PP&L to recover the full PUC-jurisdictional portion of expenses attributable to the adoption of Statement of Financial Accounting Standards 106 ("SFAS 106"). SFAS 106 requires PP&L to record the liability associated with post-retirement benefits on an accrual basis (i.e., at present value), rather than on a pay-as-you-go or cash basis. The Company's current rates recover the full SFAS 106 costs applicable to PUC-jurisdictional customers, including approximately $11 million in excess of PP&L's current cash payment obligation for post-retirement benefit claims to recover the transition obligation or accrued liability that existed as of January 1, 1993, the date PP&L adopted SFAS 106. The transition obligation is being amortized over 20 years. PP&L St. 8, p. 22; PP&L St. 8-R, pp. 41-42.

The Company determined the annual recovery of SFAS 106 costs that would occur under existing rates and included the present value of the PUC-jurisdictional portion of the generation-related amount in its calculation of stranded costs. PP&L St. 8, p. 22. PPLICA generally accepts the Company's claim, but recommends that the Commission recognize a regulatory liability for the interest earned by trust funds established by PP&L to fund post-retirement benefits other than pensions. PPLICA St. 3, pp. 26-29. In PPLICA's view, this regulatory liability should be used to offset PP&L's claimed regulatory asset.

PPLICA's proposed adjustment should be rejected. The interest identified by Mr. Kollen already is utilized to offset or reduce the projected cost of post-retirement benefits other than pensions. PP&L St. 8-R, p. 40. As Mr. Schadt explained, PPLICA's proposal, in fact, would increase PP&L's estimated generation-related stranded costs:

> PP&L included *all* of its post-retirement benefits expenses, calculated in accordance with SFAS 106, in its projections of O&M expenses as a component of wages and benefits. As such, the projected post-retirement expenses include the present value of the current year's service costs, the amortization of the transition obligation, the interest cost necessary to "grow" the liability to represent the fact that the estimated future retirement benefits are now one year closer, *less* the interest earned on trust assets. To carve out the interest earned on trust assets as a regulatory liability, as suggested by [PPLICA witness] Mr. Kollen, would simply result in higher projected O&M expenses. As a result, the estimated stranded costs for generation would increase by the same amount as the decline in net regulatory assets/liabilities. PP&L St. 8-R, pp. 42-43 (emphasis in original).

PP&L expects that PPLICA will attempt to rely on the Commission's recent Order in the PECO Restructuring proceeding to support its recommendation in this case. In that proceeding, the Commission adopted PAIEUG witness Kollen's proposed regulatory liability for SFAS 106 trust fund earnings. The Commission stated:

> Under traditional ratemaking, consumers would receive [a] credit against future expenses for these earnings. As such, they should be treated as a regulatory liability at this time. Since generation will no longer be under traditional cost-based regulation, customers would lose these credits if we did not allow them in this proceeding. PECO Order, p. 77.

As a result of this adjustment, the Commission reduced PECO's total stranded costs by $150.861 million. *Id.* See Order on Reconsideration, pp. 13-14.

The Commission's decision in the PECO proceeding is not dispositive in this case. In calculating its claimed SFAS 106 costs, PECO apparently did not credit customers with the earnings on its SFAS 106 trust fund. Instead, PECO argued that "it should be permitted to retain trust fund earnings in order to account for future inflation and cost escalation . . . ." Order on

Restructuring, p. 13. In this case, PP&L has fully reflected its SFAS 106 trust fund earnings in its calculation of stranded costs. As explained above, those earnings were utilized to reduce PP&L's claimed SFAS 106 expenses. The Company's claim, therefore, is clearly distinguishable from that addressed by the Commission in the PECO proceeding.

9. SFAS 109 (Investment Tax Credit)

With the change in Federal tax laws that allowed PP&L to take advantage of investment tax credits ("ITCs"), the Company elected to defer recognition of these credits as income by recording a liability for accumulated deferred ITCs. The amortization of accumulated ITC's, along with the related income tax effect, reduces the cost-of-service (and thus customer rates) over the lives of the assets that produced the ITCs. As a result of the adoption of Statement of Financial Accounting Standard No. 109 ("SFAS 109"), PP&L recorded a deferred tax asset to reflect the income tax effect of the accumulated deferred ITCs, and a regulatory liability (i.e., an amount owed to customers) to reflect the ratemaking treatment of the tax effect. This regulatory liability is equal to the reduction in income tax expense that will need to be recovered from customers as the balance of accumulated deferred ITCs is amortized to reduce the cost-of-service over the remaining lives of the underlying assets. PP&L St. 8, pp. 28-29.

In its Restructuring Plan filing, PP&L utilized the present value of the ITC regulatory liability to reduce or offset the present value of regulatory assets in calculating the level of its stranded costs. The methodology used by the Company to reflect the effect of the ITC regulatory liability is not opposed by any party in this proceeding.[59]

---

[59] In fact, PPLICA took the somewhat unusual step of submitting detailed testimony in support of PP&L's claim. PPLICA St. 3, pp. 9-13.

10. Retirement Of Generating Plant

In calculating its stranded cost claim, PP&L utilized the same deactivation dates for its generating facilities that were approved by the Commission in the Company's most recent base rate case at Docket No. R-00943271.[60] Specifically, the Keystone and Conemaugh generating stations are scheduled to be deactivated in 2007 and 2010, respectively. These deactivation dates also are fully consistent with the depreciation schedules reflected in PP&L's retail customer rates as of January 1, 1997. PP&L St. 10-R, pp. 33-36.

The OCA and PPLICA recommend that the Commission extend the deactivation dates for both the Keystone and Conemaugh generating stations to match the dates utilized by PECO for its share of these plants in its Restructuring Plan proceeding at Docket No. R-00973953. OCA St. 1, p. 16; PPLICA St. 3, pp. 31-32. In support of his argument, Mr. Kollen asserts that these generating stations are operated by PECO, and concludes that PECO's deactivation dates therefore are correct. PPLICA St. 3, p. 31. The opposing parties' recommendation is inappropriate, factually inaccurate and should be rejected for several reasons.

First, PP&L's proposed deactivation dates are consistent with the expected operating life for this type of generating unit. Specifically, the Keystone units began service in 1967 and 1968. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2007, these units have projected service lives of 40 and 39 years, respectively. Similarly, the Conemaugh generating units began operation in 1971 and 1972. Based on the deactivation date approved by the Commission in PP&L's last base rate case, i.e., 2010, these units have an expected operating life of 39 and 38 years. PP&L St. 10-R, pp. 35-36. As Mr. Krall explained, the Company's proposed deactivation dates properly reflect the design and operating limitations for these units:

---

60 This item is not a regulatory asset.

> Lives of 35 to 40 years are appropriate for 1970-vintage 800 MW-class once-through super-critical pressure generating units. This class of units "stretched the envelope" on certain mechanical designs and materials selections and have, in fact, seen certain stress-related problems occurring at 15 to 20 years of age which would normally not occur in lower temperature and pressure units until 30 to 40 years of age. The current lives assigned by PP&L, and approved by the Commission, reflect these issues and also are consistent with commitments made to comply with the requirements of the 1990 Clean Air Act Amendments. Any extension of these lives is speculation. PP&L St. 10-R, p. 36.

Second, the parties' reliance on PECO's proposed deactivation dates is misplaced. In fact, the various owners of Keystone and Conemaugh frequently have utilized different deactivation dates in establishing their respective rates. The Commission has reviewed and approved each of these dates.

Third, Mr. Kollen is simply incorrect in asserting that PECO's deactivation dates should be utilized because PECO operates the Keystone and Conemaugh units. The record evidence demonstrates that these generating units are operated by GPU subject to oversight by the Keystone-Conemaugh Projects Office. PECO, like PP&L, is a joint owner, and no owner may unilaterally cause investments at these stations that would extend their lives. Such investment decisions require approval by 75% of all ownership shares. Because the Commission lacks jurisdiction over five of the owning companies whose ownership shares exceed 25%, the Commission is unable to require investments to extend the lives of these stations. PP&L St. 10-R, p. 37.

In sum, PP&L's proposed deactivation dates are appropriate and should be approved. The proposed dates are identical to the dates approved by the Commission in the Company's last base rate case, and are fully consistent with the expected operating lives of the facilities. The parties' recommendations are without merit and therefore should be rejected.

11. Rate Case Expenses

The Company included in its calculation of stranded costs the present value of the generation-related portion the total annual recovery of rate case expenses that would occur through existing rates. The Commission authorized PP&L to recover rate case expenses associated with its base rate proceeding at Docket No. R-0094371 over a four-year period. PP&L St. 8, p. 26.

Raising the same argument used in opposition to PP&L's claim for deferred SSES refueling expenses, the OTS and OCA recommend that the Commission disallow the Company's claim. Specifically, Messrs. Reed and Catlin argue that the Commission previously approved normalization of PP&L's rate case expenses, not deferral and amortization of such costs. OTS St. 2, pp. 13-16; OCA St. 3, p. 12. Disallowance of the unamortized expenses would reduce the nominal balance of the Company's regulatory assets by $184,000. OCA St. 3, p. 12. The parties' recommendation is inappropriate and should be rejected.

PP&L properly included the balance of its unamortized rate case expenses as a regulatory asset in its Restructuring Plan filing. As explained by Mr. Schadt, SFAS 71 allows a regulated entity to match incurred costs with their associated revenues for accounting purposes using regulatory assets. Under SFAS 71, the recorded regulatory assets are charged, concurrently with the recovery of such amounts in rates, to the same account that would have been charged if included in income when incurred. Based on the Commission's Final Order in PP&L's last base rate proceeding, the Company appropriately created a regulatory asset in September 1995 for the 1994 Rate Case Expenses to be amortized over a four-year period. Consistent with the Act, PP&L reflected the present value of the post-1998 recovery of the generation-related costs in its calculation of stranded costs. PP&L St. 8-R, pp. 39-40.

12. Safe Harbor

On rebuttal, the Company corrected an error in its original stranded cost calculation related to the Safe Harbor facility. Specifically, PP&L's initial calculation did not include the energy revenues and the operating and maintenance expenses associated with this facility. The revenues related to Safe Harbor's capacity inadvertently were included with the Holtwood Dam hydroelectric project's revenues for capacity. The effect of properly including the remaining revenues for energy from Safe Harbor and all of its operating and maintenance costs increases PP&L's stranded costs by $38 million. PP&L St. 8-R, pp. 55-56. These corrections are shown in PP&L Exhibit JRS 8.

13. Other Regulatory Assets

PP&L notes that it has not presented a claim for stranded costs associated with its Pilot Retail Competition Program because the amounts are not known. PP&L reserves the right to claim these costs in its Compliance Filing or other appropriate point in the process. See Opinion and Order on Pilot Program Initiatives, Docket No. P-00971183, p. 26. Also, PP&L has proposed to offset this pilot program regulatory asset with a regulatory liability reflecting the refund to customers arising out of the Commonwealth Court's decision in *Popowsky v. Pa. P.U.C.*, 695 A.2d 448 (Pa. Comwlth. 1997), dealing with gross receipts tax on uncollectible accounts.

D. Other Revenue Issues

1. A&G Expenses

PP&L's stranded cost claim included the generation-related portion of its Administrative and General ("A&G") expenses. A&G expenses were allocated between generation and T&D

using the same allocation factors approved by the PUC in the Company's 1995 rate case. OCA witnesses La Capra and Lee Smith recommend that the Commission exclude $402.7 million in A&G expenses from the Company's going-forward generation-related costs on the theory that these costs are "avoidable". OCA St. 4, p. 13; OCA St. 1, p. 16. This proposal is completely inappropriate and should be rejected.

By excluding these costs from generation-related expenses and failing to reallocate them to the transmission and distribution function, Mr. La Capra effectively eliminates the claimed A&G expenses and precludes their recovery. Mr. La Capra ignores the fact that the claimed A&G costs are necessary for PP&L to continue to provide safe and reliable service to its customers. These costs will not disappear following the transition to competition. If these costs are not recovered as generation-related stranded costs, they must be reallocated and recovered through regulated transmission and distribution rates.

A similar issue arose in PECO's recent Restructuring Plan proceeding. In that case, PECO initially proposed to allocate a large portion of its A&G costs to the transmission and distribution function. The OCA and others objected, arguing that a portion of such costs was generation-related. Several parties further asserted that a reallocation of A&G expenses to generation would not increase PECO's stranded costs or that such expenses otherwise should not be recoverable. The Commission agreed that some of PECO's claimed A&G costs should be reallocated to generation using the OCA's proposed method. The Commission, however, refused to preclude recovery of the reallocated costs and concluded that PECO's stranded costs would increase by approximately $460.691 million. PECO Order, pp. 53-62.

In sum, the costs at issue either would be allowed as a stranded cost or reallocated to T&D. There is no basis for the disallowance of these reasonable costs, as proposed by the

OCA.[61]

2. Productivity Adjustment

OCA proposed a productivity factor of 0.2% to reduce projected future operation and maintenance expenses and alleges that PP&L failed to reflect possible future productivity gains. OCA St. 1, pp. 24-25. OCA provided no support for its productivity factor and, contrary to OCA's assertions, PP&L did use a productivity factor in its calculations of stranded costs. Instead of increasing administrative and general costs, a component of operation and maintenance expenses, by 2.5% annually, the inflation rate used in other portions of PP&L's calculation, PP&L reduced administration and general costs by an average of 2% annually for each year after 1997 through 2001. PP&L's method of reflecting increased productivity reduces PP&L's stranded costs even more than OCA's method. PP&L St. 8-R, pp. 54-55; PP&L Exh. JRS 7. The additional adjustment proposed by OCA is unjustified because it would "double count" PP&L's projected reductions in operation and maintenance and administrative and general expenses of $513 million. PP&L St. 2, p. 16. A portion of these expense reductions undoubtedly will come from increased efficiency of employees. There is simply no basis for the OCA□s adjustment.

3. Land Escalation

The OCA asserts that PP&L has failed to recognize the value of the real estate on which its generation units are located as a factor mitigating its overall level of stranded costs. OCA St. 1, pp. 28-29. In OCA's view, the minimum value of such real estate is $66 million. OCA Exh. RLC-6. The OCA's analysis is flawed and its adjustment is significantly overstated. Moreover,

---

[61] OCA witness Lee Smith purports to add these costs to the market price of energy. OCA St. 4, pp. 13-14. This is a nonsensical proposal. The market price of energy is the market price. Sellers in a competitive market cannot "add" costs to the market price. The OCA has improperly mixed and matched regulation and competition to disallow unavoidable A&G costs.

OCA's proposed adjustment to decrease stranded cost to reflect future land values is patently inconsistent with its opposition to PP&L's claim for fossil decommissioning expenses.

To demonstrate the flaws of OCA's presentation, PP&L produced Statement 22-R. This exhibit shows that OCA has substantially overestimated any residual value of real estate on which PP&L's non-nuclear power plants are located. Examples of the many deficiencies of OCA's presentation include the following:

(a) OCA improperly included land that cannot be sold at the Holtwood facility. PP&L St. 22, p. 5. Even after coal-fired units at Holtwood are removed, PP&L would still own and operate the hydro units which would require PP&L to continue to own the real estate.

(b) OCA erroneously included the value of land at the Conemaugh and Keystone facilities in which PP&L owns only a small minority (12%) share, and therefore, PP&L has no authority to sell the land. PP&L St. 22-R, pp. 5-6.

(c) OCA included land at plants at Montour, Sunbury and Martins Creek, where PP&L has developed recreation parks in the "buffer" areas around the generation sites. Such land probably will not be able to be sold because there would be public pressure against removing the recreation parks. There is no realistic commercial market for land that will remain a public recreation area. In all likelihood the land would be turned over to a public agency to become recreation and game lands. PP&L St. 22-R, pp. 6-7.

(d) Further, even when power plants are removed, there will still be significant electrical infrastructures on the property, such as substations, switch yards, and transmission lines, which will continue to be used to transport electricity after generation facilities are retired. Property supporting such infrastructure will not be sold. PP&L St. 22-R, pp. 7-8.

(e) OCA has failed to consider zoning limitations on future land use. PP&L St. 22-R, p. 9.

(f) OCA has failed to recognize that present generating sites would be subject to substantial costs for environmental cleanup, which has been ignored in OCA□s analysis. PP&L St. 22-R, p. 13.

(g) OCA has failed to recognize that the value of land must be allocated between state and federal jurisdictions and that only the state portion in a value of the land could be available to offset state jurisdictional stranded costs. PP&L St.

22-R, p. 14.

(h) OCA has used a 4% escalator to project future land values. Such projections are completely unfounded in the geographic areas where PP&L's generation facilities are located. Land values are flat, at best. PP&L St. 22-R, pp. 16-17.

OCA's adjustment to stranded costs for the residual value of land on which generating units are situated is seriously overstated and should be rejected.

4. Capital Additions

As explained in Section III, above, OCA recommends that the Commission adopt the asset value methodology to determine the Company's stranded costs. Under this approach, the OCA calculates PP&L's generation-related stranded costs by calculating the difference between the net book value of the generation-related assets at January 1, 1999 and the estimated market value of such assets as of that date. OCA St. 1, p. 14. The OCA determined the market value of PP&L's generating assets by calculating the market revenues PP&L could expect to receive less going-forward operating costs, including capital investments and taxes. OCA St. 1, pp. 14-15. In its calculations, the OCA treats capital additions as expenses in the year in which they are incurred. Similarly, the OCA reflects the full associated tax deductions in the year in which the underlying capital expenditure is incurred.

The OCA's treatment of capital additions is in error. The proper treatment of capital expenditures is to record depreciation expense ratably over the life of the investment and to provide for a return on the undepreciated balance, i.e., rate base. Because OCA's asset value method cannot handle this complexity, Mr. La Capra makes the simplifying assumption that the entire expense was incurred in the year it was made. From an expense standpoint this is acceptable, as long as the discount rate is the same as the return which would have been allowed if the investment were depreciated under normal ratemaking practice.

The problem with OCA's analysis lies in its treatment of taxes. OCA assumes that the tax deduction for the entire capital expenditure can be taken in the year it was made. This, of course, is not true. The tax laws require that a deduction equal to the nominal value of the expenditure be spread over the life of the investment utilizing IRS tax depreciation guidelines. As a result of this error, OCA significantly understates the actual cost of capital additions and overstates net market revenue by overstating the tax reducing effect of the expenditure. As shown in Table D, this error caused the OCA to understate PP&L's stranded costs by $165.318 million.

5. CWIP

The starting point for the OCA's asset value method is the projected net book value of PP&L's plant at January 1, 1999. OCA understates this balance by failing to include plant currently under construction which will be in service by January 1, 1999. The PUC adopted a Construction Work in Progress ("CWIP") adjustment in the PECO Restructuring Order, PECO Order at pp. 81-82, and the OCA did not oppose that adjustment.

If the asset value method is used, a similar adjustment is required in this case, which increases net plant by $108.928 million, as shown in Table D.

6. Taxes Recoverable

In its Restructuring Plan filing, PP&L reflected $189 million for taxes recoverable in its calculation of stranded costs. The Company's claim was calculated using the regulatory method which reflects the recovery of these costs over a 30-year period. As explained by Mr. Schadt, that method permits a simple straightforward calculation of taxes recoverable:

> A comparison of future book depreciation with future tax depreciation identifies exactly the future period in which the taxes will become payable. This also is the period in which taxes recoverable should be collected from ratepayers, under traditional ratemaking. Note that this is true because the proper linkage exists between rate base, deferred taxes and taxes recoverable. As rate

> base is depreciated over time, deferred taxes become payable to the government and taxes recoverable become due from ratepayers. PP&L St. 8-R, p. 14.

As explained in Section III, *supra*, OCA and PPLICA recommend that the Commission adopt the asset value method to calculate PP&L's stranded costs. As all parties acknowledge, however, the asset value method cannot be used to calculate taxes recoverable. To address this problem, Mr. La Capra reverts to the regulatory method to calculate these costs. However, it is only appropriate to utilize the regulatory method to calculate stranded costs related to taxes recoverable if such method is used consistently with the regulatory model, i.e., the difference between book depreciation and tax depreciation "drives" taxes recoverable. PP&L St. 8-R, p. 16. As Mr. Schadt explained, "[i]f book depreciation is eliminated from the calculation of stranded costs, as it is in the asset value model, there is absolutely no theoretical justification for amortizing taxes recoverable on the basis of book depreciation, and alternative amortization logic must be developed . . . ." PP&L St. 8-R, p. 16.

Existing accounting rules will require PP&L to recognize that stranded generation costs will be recovered through the CTC over a seven-year period. Consequently, related unfunded deferred taxes also will reverse over the same seven-year period, which in turn requires the reversal of taxes recoverable over the same seven-year interval. Thus, when properly calculated under the asset value method, stranded costs for taxes recoverable equal the present value of the Company's $548 million of taxes recoverable discounted over a seven-year period, or $419 million. PP&L St. 8-R, pp. 16-17. Mr. La Capra's inconsistent, hybrid approach fails to reach this result.

As noted above, PP&L is requesting rate recovery of only $189 million, if its proposed regulatory method is adopted. If the asset value method is adopted, PP&L's claim properly is $419 million.

7. Deferred Taxes

The asset value method, as presented by OCA and PPLICA, purports to determine the market value for which the utility's assets could be sold today. OCA St. 1, p. 14. The difference between that market value and the book value of the assets equals the utility's stranded costs. OCA, for example, concludes that the market value of PP&L's generating assets is $3.1 billion as compared to a book value of $3.25 billion, yielding a stranded generation plant of approximately $150 million.

What the OCA and PPLICA fail to account for is deferred taxes. Under the Internal Revenue Code, PP&L is permitted to depreciate its assets for tax purposes faster than its book depreciation. This generates larger tax deductions and lower taxes in the early years of a plant's life and lower tax deductions and higher taxes in the later years. This amounts to an interest free loan from the federal government. For ratemaking purposes, tax expense on certain plants is calculated using book depreciation, thereby yielding higher tax expense for ratemaking purposes than actually paid to the federal government. This difference between actual taxes and ratemaking taxes is called deferred taxes and is deducted from rate base to give ratepayers the time value of the interest free loan received from the government.

The key point is that deferred taxes are only a loan and must be repaid. They can be repaid in two ways: Over the life of a plant as the deferred taxes "reverse," or immediately when the asset is sold. Under the revenue requirements model, used by PP&L, these deferred taxes reverse over time and are reflected in future revenue requirements. This does not and cannot happen under the asset value method which purports to calculate the value of the assets if they were sold today. However, if those assets were sold today, the deferred taxes would be immediately due and payable.

Mr. Schadt demonstrated this point in his rejoinder testimony, as follows:

Q. Have the OCA and PPLICA correctly applied their asset value methods?

A. No, they have not. The goal of both methods should be to permit the utility to recover the book value of its investment in generation.

PP&L's method recovers that book value over the remaining life of the plants. The OCA/PPLICA method determines the price a willing buyer would pay for PP&L's generating plant today, and permits the recovery of the difference between that price and the net book value as a stranded cost.

Unfortunately, neither the OCA nor PPLICA's application of the asset value method produces that goal. For example, Mr. Falkenberg's Surrebuttal Exhibit RJF-9A calculates a market value of PP&L's generating plant of \$2.6 billion, adding \$200 million for inventory, and a recommended stranded cost recovery of another \$250 million. PPLICA would allow PP&L a total recovery of approximately \$3.1 billion

However, the book value of PP&L's plant is \$4.3 billion, leaving PP&L about \$1.1 billion short of full recovery of book value. A similar result occurs under the OCA's proposal.

Q. Why does this shortfall occur?

A. Well, it occurs primarily because of their mishandling of deferred taxes. If the company were to sell its generating assets on January 1, 1999, for the market value estimated by either the OCA or PPLICA, the associated deferred taxes would immediately reverse and become payable in 1999.

However, the OCA/PPLICA method ignores this fact and treats deferred taxes as if they will not reverse upon the sale of related assets. As a result, they have significantly understate the company's actual stranded costs. Tr. 1541-42. (8/26/97).

OCA and PPLICA shortchange PP&L by failing to reflect the fact that deferred taxes must be paid when the plant is sold. By failing to reflect these tax payments, they overstate the value of PP&L's assets.

OCA and PPLICA may argue that PP&L has no present plan to sell its plant and may own and operate it for many years. See Tr. 1547 (8/26/97). This is not the point. The asset value model assumes the plant will be sold and must be calculated on that basis. Otherwise, the revenue requirement model should be used, which properly reverses deferred taxes over the life of the plant. This is yet another example of the mix and match approach used by OCA and

PPLICA. They purport to use the asset value method, but then revert to revenue requirements when it suits their purpose of reducing PP&L's stranded costs. If the asset value model is used, it should be used consistently. The asset value of PP&L's generating assets to PP&L is their market value less taxes which must be paid upon their sale. Correction of this error increases OCA's stranded cost allowance by $281.671 million as shown on Table D.

VI. DETERMINATION OF PRESENT VALUE

As explained in Section III, above, PP&L used the regulatory method to calculate its stranded costs. Under this method, the Company compared the revenue stream it could have received under traditional cost-of-service regulation with the stream of revenue it could receive in a competitive market. PP&L discounted the difference between these two amounts to January 1, 1999 using a discount rate of 7.92%, which is PP&L's after-tax weighted average cost of capital ("WACC"). PP&L St. 8-R, p. 5; PP&L Exh. JRS 1, p. 1. The OTS, OCA and OSBA oppose both the Company's proposed discount rate and the application of such rate. As explained in detail below, each of the arguments raised by the parties is without merit and should be rejected.

A. Appropriate Discount Rate

1. Return on Common Equity

The appropriate discount rate is in part a function of the appropriate return on equity. Several parties addressed the return on equity in connection with the allowed revenue under regulation. This issue is discussed in Section V.B.

2. OSBA's Proposal

OSBA witness Knecht argues that PP&L's proposal to use a 7.92% after-tax WACC "would provide a higher [net present value] return to equity holders under deregulation plus CTC than under continued regulation." OSBA St. 1, p. 21. To address this alleged problem, Mr.

Knecht asserts that the Commission should adopt PP&L's proposed 11.5% after-tax cost of equity as the appropriate discount rate. OSBA St. 1, p. 16. Under Mr. Knecht's proposal, the Company would underrecover less than $100 million of its total stranded costs. OSBA St. 1, p. 24. Mr. Knecht purports to support his adjustment both algebraically and with an example. OSBA St. 1, pp. 18-21; OSBA Exh. RDK-2, Schedules 1-3. Mr. Knecht's logic and algebra, however, are flawed.

Mr. Knecht's proposal completely ignores the fact that PP&L has both equity and debt investors. Indeed, Mr. Knecht conceded this point during cross-examination. Tr. 804 (8/19/97). As explained by Mr. Guth:

> a utility's earnings on capital invested consist of both earnings on equity and earnings on debt. Using the after-tax WACC takes into account the balance of earnings between equity and debt. PP&L St. 19-R, p. 23.

Under Mr. Knecht's proposal, however, a component of PP&L's total returns, i.e., interest paid to debt-holders, will be discounted at equity rates. PP&L St. 19-R, p. 24. This mismatch is clearly inappropriate and should be rejected.[62]

---

[62] On surrebuttal, Mr. Knecht argues that he subtracted out debt costs from his analysis, such that only equity cash flows are discounted at equity rates. OSBA St. S-1, p. 5. Mr. Knecht's argument, however, fails to address the mismatch that results from his recommendation.

Similarly, Mr. Knecht offered a new Exhibit RDK-S1 on surrebuttal. That exhibit allegedly shows that the WACC is an average of equity and debt rates of return that fails to produce the same discounted cash flows when equity rates are applied to equity cash flows and debt rates are applied to debt cash flows. OSBA St. S1, p. 8. This exhibit completely fails to support Mr. Knecht's proposal. Mr. Knecht is not recommending that the Commission adopt the methodology reflected in Exhibit RDK-S1, i.e., application of equity rates to equity cash flows and debt rates to debt cash flows. Mr. Knecht proposes to apply an after-tax cost of equity to *all* components of PP&L's total returns.

B. Application of Discount Rate

1. Income Taxes

The OCA asserts that PP&L improperly applied an after-tax discount rate to calculate the present value of pre-tax revenue requirements and market prices. OCA St. 1, p. 13. As a result, the OCA claims that the Company overstates its stranded costs by $880 million. Id. The OCA's concerns are without merit and should be rejected.

As explained by Mr. Guth, stranded costs are analogous to economic damages because they represent a decrease in value caused by some act or event, in this case, the transition from regulated rates to market-based rates. PP&L St. 19-R, p. 20. As such, taxable stranded costs properly should be measured utilizing pre-tax cash flows and after-tax discount rates:

> In computing economic damages, we want to compensate the owner of damaged assets just enough to restore her to her prior position. Since future cash flows -- as well as the subsequent return earned on those cash flows -- are taxable, we must discount to present value taking into account tax effects by using an after-tax discount rate. But, since damage awards are ordinarily taxable, we must adjust the cash flows to pre-tax levels so that the owner is made whole after taxes on damages are paid. PP&L St. 19-R, p. 21.

Although Mr. La Capra and Mr. Falkenberg utilize an after-tax discount rate to calculate stranded costs, they err by computing PP&L's stranded costs based on *after-tax* revenue requirements and market prices. Specifically, these witnesses reflect income taxes in calculating the value of PP&L's generating assets, but fail to adjust stranded costs upward to account for the taxability of CTC revenues. PP&L St. 19-R, p. 21. As Mr. Guth explained, Messrs. La Capra and Falkenberg:

> computed what they assert is the market value of PP&L's generating assets after taking into account income taxes. That procedure is all right, so long as measured stranded costs are then adjusted upward to take into account the taxability of CTC

revenues that are based on stranded costs. Thus there really are two alternatives where the present value amount of future cash flows is taxable income:

1. use pre-tax cash flows, and after-tax discount rates to compute the present value of taxable income; or

2. use after-tax cash flows, and after-tax discount rates to compute the present value of after-tax income, then gross up the result for tax coverage. PP&L St. 19-R, pp. 21-22.

The OCA's proposal is incorrect because it fails to adopt either of these approaches and effectively disallows the recovery of income taxes. The OCA's recommendation regarding application of the discount rate therefore should be rejected.

2. Discount Rate Method

PP&L discounted its revenue requirements on a monthly basis. The OCA discounted on a semi-annual basis. A monthly calculation is more accurate, is consistent with PUC, practice in calculating ECRs and was approved in the PECO Restructuring proceeding (Order on Compliance Filing, p. 6). As shown in Table D, the OCA's method understates stranded costs by $48.374 million ($71.072 for Market Value, less $5.815 million for Regulatory Assets, less $8.982 million for NUG Contracts and $7.899 million for Nuclear Decommissioning).

VII. RECOVERY OF STRANDED COSTS

A. Design of the Competitive Transition Charge

Under Section 2808(a) of the Act, electric distribution companies will recover their stranded costs through CTCs. These charges will be applied to every customer of electric distribution companies. The rate design for PP&L's CTC is based upon principles derived from two different sources. First, the Act contains a set of principles that are to be followed in designing CTCs. Second, PP&L has followed fundamental principles of rate design that are widely accepted and applied in utility ratemaking.

Three statutory provisions influence the rate design of PP&L's CTC. First, the CTCs are constrained by the rate caps. Under Section 2804(4)(ii) of the Act, there may be no increase in the generation component of rates, which includes the CTC, for nine years from the Act's effective date, January 1, 1997, through December 31, 2005. Second, Section 2808(a) of the Act mandates that the CTC be designed "in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the Commission in the electric utility's most recent base rate proceeding." Third, PP&L's CTCs are designed in a manner to promote the overall purpose of the Act, which is to establish an active and viable retail market for electric generation.

In addition to these statutory considerations, PP&L has applied sound ratemaking principles in designing its CTC. PP&L has sought to provide a more efficient marginal price signal to customers. PP&L St. 9, p. 20. Further, PP&L has simplified its delivery service rate design.

PP&L used a "bottom-up" approach to design its CTC, PP&L St. 9, pp. 23-26; starting with its present rates. The first step was to determine for each rate in each rate schedule, the portion of the rate related to delivery of electric energy. The portion of revenues under each rate schedule attributable to distribution service was determined by application of allocation percentages based upon a test year ended December 30, 1995.[63] Since customer costs are not generation-related, 100% of customer charges were determined to be for delivery service. The remaining amount of delivery costs under each rate schedule is to be recovered under a uniform amount per kWh for each rate schedule. The delivery portion of each rate was then subtracted from the total rate; the remainder is the generation portion of the rate.

---

[63] These allocation percentages were accepted in the Commission's Order entered in PP&L's most recent base-rate case (Docket No. R-00943271, order entered on September 27, 1995, at 197).

The next step is to subtract from the generation portion of each rate the projected retail market price of electric energy. The remainder after this subtraction is the portion of the rate under the rate cap that is available for use as the CTC.

As explained above, PP&L's total stranded costs are approximately $4.5 billion.[64] PP&L has determined that, under the rate cap, the maximum CTC revenue that can be attained over the transition period through 2005 is only $4.0 billion. PP&L St. 10-R, p. 3. Thus, due to the rate caps, PP&L's projected CTC revenues will fall $500 million short of recovering all of PP&L's stranded costs. Therefore, PP&L set its proposed CTCs at the maximum amounts available under the rate cap after allowing for the projected retail market price of electric energy and the portion of each rate for delivery services.

Although the rate cap does not change throughout the transition period, the projected retail market price of electric energy increases each year of the transition period. Therefore, for each rate, there is a different energy and capacity credit and a different CTC for each year of the transition period through 2005. See, e.g., Exh. OGK 2, pp. 20-21.

PP&L's rate design for its CTC meets each of the statutory and ratemaking principles identified above. First, it successfully meets the Act's rate cap requirements. By calculating the CTC as the residual remaining after subtracting the delivery portion of the rate and the projected cost of electric generation during the transition period (which is the maximum charge for PP&L's Basic Utility Service ("BUS")) to last resort customers means that PP&L's proposed CTCs cannot exceed the rate cap.

Second, PP&L's rate design will not cause shifting of costs between rate classes or within

---

64 This figure includes, of course, GRT and is subject to income tax. PP&L's actual recovery of stranded cost will be less than $2.25 billion after taxes. See Table E.

rate classes. The generation portion and the delivery portion of PP&L's present rates were determined by application of allocation percentages from the cost of service study used to design PP&L's present rates. PP&L St. No. 3, pp. 6-7; Exh. JMK 1. Use of the cost of service allocation percentages from the electric distribution company's most recent base-rate case to unbundle rates has been approved by the Commission. PECO Order, pp. 109-10.

Third, CTCs have been designed to achieve simplicity in the delivery service rate design. The CTCs have declining block rate designs that follow PP&L's presently-effective rate design. The delivery charge includes the presently-effective customer charge and flat usage charges per kWh.[65] Therefore, when the CTC is eliminated at the end of the transition period, the remaining charges of PP&L under PP&L's rate schedules for most customers will be a customer charge combined with a flat energy charge for usage. Customers can understand this pricing structure and will be able to work with it to obtain electric energy under the most favorable terms and conditions. PP&L St. 9, p. 21 .

OCA and OSBA recommend, based on an assumption that PP&L will be allowed to recover a much lower level of stranded costs than it has proposed, that recovery of stranded costs be spread over the full transition period even if a substantial portion of stranded costs are disallowed. OCA St. 4, pp. 9-14; OSBA St. 1, p. 12. These recommendations should be rejected. Such an unnecessary delay in recovery of stranded costs would impose on PP&L an increased risk that it will be unable to recover all of its allowed stranded costs if market conditions change in the future. Moreover, the CTC should be set at the maximum level consistent with the rate cap until the allowed level of stranded costs is recovered because this approach will eliminate the distortions in electric energy market prices caused by the CTCs at the earliest possible date. PP&L St. 9-R, pp. 22-25.

---

[65] There will also be demand charges for rate schedules presently containing demand charges.

Various parties in this proceeding have proposed alternative methods for PP&L to recover its stranded costs. The proposals by other parties consist of "levelizing" or otherwise unnecessarily spreading recovery of stranded costs over time. For a summary of various alternatives, see, e.g., OCA St. 4-S, pp. 2-3, OCA Exh. LS-10. These proposals should be rejected. First, they are based on the assumption that a substantial portion of PP&L's stranded costs will be disallowed by the Commission. For the reasons explained previously in this Brief, however, such assumption is unfounded. Second, levelizing recovery of stranded costs has the effect of shifting that recovery from the early years of the transition period to the later years. The result is a significantly adverse impact on PP&L's financial indicators in those early years, compounding the financial impact of any disallowance of stranded cost recovery.

B. Prohibition on Inter and Intra Class Cost Shifting

Certain intervenors contend that PP&L's methodology for establishing its CTCs is inappropriate. Specifically, AARP contends that costs should be reallocated so that a larger share of CTC revenues is derived from non-residential customers. AARP St. 1, pp. 28-29. The Environmentalists contend that the Commission should take a fresh view of allocating stranded costs among the rate classes. Environmentalist St. 1, p. 26. These proposals should be rejected because they directly contravene the mandates of Section 2808(a) of the Act, which requires that the CTC be established in a manner that does not shift cost recovery either between classes of customers or within a customer class, and in a manner that maintains consistency with the allocation methodology accepted by the Commission in the utility's most recent base rate case.

C. CTC Reconciliation and Tracking

Section 2808(f) of the Act provides that annual CTC revenues shall be reconciled with the amortization of stranded costs authorized by the Commission for the same period. PP&L proposes to implement this statutory mandate by following procedures, subject to one exception, similar to the annual Energy Cost Rate ("ECR") reconciliation procedures that had been in place in Pennsylvania for many years prior to passage of the Act. PP&L St. 3, p. 17. PP&L proposes to track, on a system basis, its annual CTC revenues and compare those revenues with the annual amortization authorized by the Commission. PP&L would submit quarterly filings to the Commission reporting the results of the tracking process. However, in a departure from ECR practice, PP&L would not change its CTC annually to reflect overcollections or undercollections.

Because PP&L's rates will be set at the rate caps throughout the transition period, PP&L would be precluded by the rate caps from recouping from customers any prior period undercollection. Accordingly, PP&L is proposing that the CTC application period be extended or contracted to permit a net reconciliation of overcollections or undercollections. That is, if CTC revenues were more than the amount authorized by the PUC, the CTC would be terminated at the appropriate time prior to December 31, 2005. Conversely, if CTC revenues were less than the amount authorized by the PUC, the CTC period would be extended beyond December 31, 2005.

Section 2808(b) of the Act permits the Commission, "for good cause shown," to order an alternative CTC payment period which may be longer or shorter than the nine-year period. PP&L has shown good cause why the period for application of the CTC should be extended if CTC revenues during the period ending December 31, 2005, fall short of the level of stranded costs that PP&L is authorized by the Commission to recover from customers. PP&L St. 3, pp. 18-19.

PP&L's proposal to adjust the CTC application period for reconciliation of stranded costs also protects the interests of customers. First, if the Commission approves PP&L's proposal to extend the period for recovery of stranded costs beyond December 31, 2005, PP&L voluntarily will extend the generation-related rate cap to coincide with the extension of the period for application of the CTC. PP&L St. 3-R, p. 26. Second, the CTC will be known and predictable throughout the transition period enhancing the ability of customers to compare offerings by alternative electric energy suppliers and calculate potential savings. Third, PP&L has kept the

CTC mechanism as simple as possible by not reflecting any calculations of interest on overcollections or undercollections of the annual CTC amortization in the reconciliation process. PP&L St. 3-R, p. 25.

In the PECO case, the Commission rejected a similar CTC reconciliation proposal, concluding that Section 1307(e) of the Code, 66 Pa.C.S. § 1307(e), requires a dollar adjustment over an appropriate 12-month period. PECO, p. 113. However, Section 1307(e) begins with the phase "[a]bsent good reason being shown to the contrary," which grants broad discretion to the Commission in this area. In its PECO order, the Commission appears to conclude that this discretion can be exercised only after hearings on the reconciliation adjustments. *Id.* Unlike PECO, however, PP&L has not proposed extending the CTC application period to recover allowed stranded costs, rather the only extension proposed would be for the collection of reconciliation amounts. The Commission should be able to exercise its discretion at any time; the hearing requirement only limits the time when it can enter a reconciliation order. PP&L submits that it has provided good reason for modifying the requirements of Section 1307(e) and that the Commission should approve its proposed CTC reconciliation mechanism.

Certain parties contend that PP&L should not be permitted to extend the period for application of the CTC to customers' bills unless PP&L applies to the Commission for specific permission for such an extension near the end of the transition period. PPLICA St. 1, p. 6; OSBA St. 1, p. 36. Apparently, such an application would allow the Commission to determine in a future proceeding whether stranded costs in fact had turned out to be equal to or less than the amount projected in this proceeding or whether further recovery should be denied for any number of unspecified reasons. Although other parties' testimony on this subject is vague, their proposals suggest an unfair, one-sided review in which stranded cost recovery could only be decreased, even if stranded costs turned out to be greater than the level authorized by the Commission.

These proposals are ill-founded and contrary to the Act. Under Section 2808(f) of the Act, the reconciliation process consists solely of comparing CTC revenues with levels of stranded costs authorized by the Commission to be recovered. No provision of the Act indicates that the reconciliation process should provide an opportunity for all parties to relitigate the stranded costs issues being decided in this proceeding. Moreover, such relitigation for reconciliation purposes would impose unnecessary administrative burdens on the Commission and all parties.

For all these reasons, other parties' proposals that an extension of the CTC application period beyond December 31, 2005, be made conditional upon future Commission approval should be rejected.

OCA has recommended that the CTC be reconciled by rate class. OCA St. 4, pp. 17-18.[66] This proposal should be rejected for several reasons. First, there is no support for the proposal in the Act. Section 2808(f) is silent on the subject. Second, and of greater importance, OCA's proposal would not solve the perceived problem that it is intended to address. Instead, it would create additional problems. Apparently, OCA is seeking to address a concern that stranded cost recovery will be usage dependent, and different rate classes will pay more or less than allocated amounts depending on future levels of usage. However, under OCA's proposed reconciliation by rate class, this "problem" will remain unresolved for customers within a rate class. Inevitably, customers using more energy in the transition period will pay more stranded costs than they would pay under allocations based on historical usage. Similar problems arise from additions and losses of customers. For example, in rate schedules with a few large customers, hardships

---

[66] It is noted that the Commission required PECO to reconcile CTC revenues and costs by class. PECO Order, p. 112. In that Order, however, the Commission did not address PP&L's explanations, provided above, that class reconciliation is not required by the Act or customers' interests. Therefore, this issues should be given fresh consideration by the Commission in this proceeding.

could be caused to remaining customers if one member of the rate class went out of business early in the transition period.[67] Problems also would be caused by having the CTC terminate at different times for different rate schedules. Under these circumstances, some customers may be able to switch their service to a rate schedule without a CTC, thereby harming other customers or the Company.

OCA's proposal for CTC reconciliation by rate class should be rejected. The "problems" it seeks to address are a basic part of almost any rate design and are unavoidable unless the CTC is to be an entirely fixed charge and based on historical levels of usage. No party has made such a proposal.

D. CTC and Rate Cap Extension

As discussed above, PP&L has proposed that the CTC and generation rate cap be extended (or decreased) to reconcile actual CTC collections with the level of stranded costs allowed by the Commission. The record of this proceeding does not contain any other proposal to extend the CTC or rate cap. No party presented any evidence that such an extension would be necessary or appropriate. Accordingly, PP&L would oppose any attempt to impose a general extension of the CTC and generation rate cap.

E. Return on Unamortized CTC Balances

Pursuant to the Act, electric generation-related stranded costs are to be "determined on a net present value basis over the life of the asset or liability as part of its restructuring plan . . . ." See Section 2803, definition of "transition or stranded costs." Previously, in Section VI of this Brief, PP&L explained the proper rate for discounting the value of future stranded costs to

---

67 This potential difficulty could be ameliorated if the reconciliation were by customer class (*i.e.*, residential, commercial, industrial) and not by rate class (*i.e.*. by rate schedule).

January 1, 1999.

Similarly, a proper net present value determination also must recognize that PP&L's stranded costs will be recovered over a seven-year period ending December 31, 2005. For the reasons that stranded costs are discounted to net present value, PP&L's recovery of stranded costs must reflect an appropriate return on uncollected CTC balances.

In the PECO Order, the Commission set the applicable rate of return on unamortized CTC balances at PECO's long term debt cost rate. PECO Order, p. 108; *see also* PP&L St. 19-R, pp. 28-29. PP&L's long-term debt cost is 7.89%. PP&L Exh. JRS 1, Tab A, Attach. 1.

Regardless of the cost rate, however, a substantial portion of PP&L's assets, including stranded assets, are financed with securities on which PP&L pays dividends that are subject to income taxes. For this reason, the portions of the amount to be inflated must be "grossed up" for income taxes. Exhibit JRS 1, Tab A, Attachment 1, provides PP&L's capital structure and cost rates. Exhibit JRS 1, Tab A, p. 4, provides its composite income tax rate of 41.4935%. Using these data, that have not been controversial in this proceeding, produces the appropriate rate to be applied to amounts to be recovered through the CTC over seven years. See Table F.

Thus, the appropriate overall, pretax rate of return allowed on PP&L's unamortized CTC revenues, during the seven-year period, is 10.86% using PP&L's average long-term debt cost as the return to all classes of PP&L securities. If PP&L's actual cost of capital were used, the figure would be 13.54%.

Failure to allow any return on unamortized CTC balances, as suggested by several parties, would amount to an unlawful taking of PP&L property without just compensation. Unamortized CTC balances represent the very same costs upon which the Commission was required to allow a reasonable return. See 66 Pa.C.S. § 1301; *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315 (1989). Converting the manner in which those costs are recovered from traditional rates to a CTC charge does nothing to change PP&L entitlement to a reasonable return on its investment.

F. Calculation of the CTC Applicable to Interruptible Service Customers

PP&L provides interruptible service under three rates schedules — IS-1, IS-P and IS-T. PP&L proposes to continue service under these rate schedules during the transition period. Service, however, would be limited to customers presently receiving interruptible service and to customers who choose to purchase PP&L's BUS Service. *See, e.g.*, PP&L Exh. OGK 2, p. 30C.

Several customers objected to PP&L's proposal to limit the availability of interruptible service to customers who utilize PP&L's BUS Service. PPLICA Sts. 4 and 5. These customers contend that they should be able to continue to receive interruptible delivery service rates from PP&L and shop for alternative sources of electric generation. These contentions are meritless and should be rejected.

The CTC for the interruptible rate schedules is calculated in the same manner as for all other rate schedules, *i.e.*, it is the remainder after the projected retail price of electric generation and the delivery component of the rate are subtracted from the fully-bundled interruptible rate. As a result, the CTCs applicable to the interruptible rate schedules are extremely small. For example, in 1999, the tailblock CTC under Rate Schedule IS-T is 0.257¢ per kWh[68], and this amount is reduced every year through 2005 when the tailblock CTC is a negative 0.006¢ per kWh.

These low CTC rates result because the interruptible rates are deeply discounted. These discounts clearly are generation-related. As stated by the Commission:

---

[68] There is also a CTC per kilowatt of billing demand. Like the CTC applicable to the energy portion of the rate, the CTC per kilowatt of demand decreases from $3.145 in 1999 to $1.665 per kilowatt in 2005.

In addition to the benefit to be received by the utility of load retention (a response of the utility to economic concerns of customers, some of whom were at risk of closure, and contraction or relocation of operations),[[69]] interruptible load enabled the utility to avoid the need for generation capacity assigned to meet short duration peak. *Pa. P.U.C. v. PP&L, Docket No. R-00943271*, pp. 220-21 (September 27, 1995).

Another benefit to PP&L's system of providing interruptible service is that PP&L can interrupt sales to interruptible customers when the cost to PP&L of generation service is exceptionally high, thus permitting PP&L to avoid building and operating costly peaking generating units..[70] PP&L St. 11-R, pp. 3-4. Under competition, the benefits of providing interruptible service are available to any alternative supplier of electric energy, not only PP&L. However, if an interruptible customer of PP&L purchases electric energy from alternative suppliers, the interruptible nature of the service will benefit the alternative supplier and possibly its customers, but not PP&L or PP&L's other delivery service customers.

Certain customers' proposals to continue to utilizing PP&L interruptible rate schedules while purchasing from alternative suppliers are simply unfair. Under these circumstances, the interruptible customers would continue to receive from PP&L the benefit of a deeply discounted rate for interruptible delivery service while providing no reciprocal benefits to PP&L or its customers. Presumably, such customers also would be able to obtain from alternative suppliers prices for electric energy that are lower than prices for firm service, thereby obtaining a second

---

69 The Commission's reference to economic concerns, although possible justification for a rate lower than what otherwise be applicable, is unrelated to the interruptible nature of the service and the related cost savings.

70 Presumably this benefit of interruptible service was not discussed at length in the most recent PP&L rate case at Docket No. R-00943271 because it was a base rate case. PP&L's cost of electric energy normally would not be addressed in the base rate case; prior to passage of the Act, costs of electric energy were addressed more commonly in proceedings under Section 1307 of the Public Utility Code.

discount. The second discount, from alternative suppliers, may be justified in the market given the interruptible nature of the service required by the customer. The first discount in the delivery service rate from PP&L, however, is completely unjustified under these circumstances.

PP&L's position in this proceeding is substantially similar to the Commission's conclusion at pp. 117-18 of the PECO Order. Interruptible service will be available to customers purchasing BUS Service from PP&L. Customer choice also will be available to customers on interruptible rate schedules, but they will be required to migrate to rate schedules without generation-related discounts to exercise customer choice. The only respect in which PP&L's position on interruptible service differs from the Commission's Order in PECO is that PP&L has not proposed any discounted rate for interruptible transmission and distribution service.

Customers on interruptible rate schedules may contend that the interruptible nature of their delivery service from PP&L would still justify the deeply discounted rates because that service is theoretically interruptible for local transmission or distribution emergencies. Such contentions, however, have no merit in actual practice on PP&L's system. All of PP&L's transmission and distribution facilities have been designed to meet peak loads. In fact, to date, PP&L has never interrupted service under the interruptible rate schedules due to load peaks on transmission or distribution facilities. To the contrary, all interruptions requested by PP&L have been the result of generation emergencies on the PJM interconnection, for emergency tests of interruptible service customers or for economic reasons. PP&L St. 11-R, p. 8. There is no evidence in this proceeding that contradicts these conclusions concerning the PP&L system. Because, there are no savings from any possible interruptions of transmission and distribution service, there is no basis for discounting any such service.

Customers receiving interruptible service also object to the provisions of PP&L's proposed tariff, Exhibit OGK 2, p. 30E, which give PP&L more discretion in interrupting service for economic load control. This provision, however, is appropriate to protect PP&L's other customers. All customers using PP&L's BUS Service will receive bills for service that are based upon an annualized, average cost of such service, subject to the rate cap. Therefore, if customers receiving interruptible service use electric energy when prices are high, the cost that such customers cause PP&L to incur ultimately will be shared with other customers if the price does not exceed the rate cap.[71] PP&L's present tariff rule, with interruptions limited to 200 hours per year or 2.3 percent of the time (200 ÷ (24 x 365)) is simply not sufficient to protect the interest of other PP&L customers receiving BUS Service.

Moreover, during interruptions for economic load control, customers on interruptible rate schedules are not required to terminate use of electric energy. To the contrary, they are only required to make an economic choice. If such a customer uses electricity during interruptions for economic load control, its only predicament is that it must pay the charges under the interruptible rate schedule plus PP&L's estimated cost of replacement capacity and energy. PP&L Exh. OGK 2, p. 30F.

VIII. RATE DESIGN AND TARIFFS

A. Customized Rate Design

PP&L has proposed an innovative rate design for its CTC. PP&L's proposed CTC will be calculated for customers individually, that is, "customized," based upon their 1996 usage of electric energy. PP&L's customized rate design ("CRD") shifts one half of each customer's total CTC from usage-based charges to fixed monthly CTC customer charges. PP&L St. 9, p. 5.

---

[71] Of course, when the cost of BUS Service is greater than the rate cap, the effect of providing customers on interruptible rate schedules with firm service when costs of electric energy is high will be borne by PP&L's shareholders.

PP&L's principal proposal is that this customized rate design ("CRD") should be optional to all customers.[72]

The effect of the CRD, in comparison with a more traditional usage-based (cents-per-kWh) charge are several. First, if each customer were to use during any year of the transition period, the same amount of electric energy as it used during 1996, the customer would pay the same total amount of CTC under both the CRD and the traditional, usage-based rate design. If, however, a customer were to use more electric energy per year during the transition period than in 1996, the customer would pay less under the CRD than under the traditional rate design. Conversely, if a customer were to use less electricity during the transition period than in 1996, the customer would pay more under the CRD than under the traditional rate design.

PP&L's proposed CRD promotes a principal objective of the Act, which is to stimulate growth in the Pennsylvania economy. For example, the General Assembly's Declaration of Policy in Section 2802 of the Act includes the following:

> (6) The cost of electricity is an important factor in decisions made by businesses concerning locating, expanding and retaining facilities in this Commonwealth.
>
> (7) This Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs.

The CRD will be calculated individually for each customer. First, each customer's usage during 1996 will be priced at rates established in this proceeding using a CTC calculated under

---

[72] PP&L originally proposed a CRD that was mandated for non-residential customers served on major rate schedules, not optional for non-residential customers. PP&L St. 10 pp. 5, 15. During the hearings, PP&L proposed that the CRD be optional for all customers. Tr. 733-34 (8/19/97).

traditional, usage based rates. This amount will then be divided by 12 to determine a monthly amount. One half of the monthly amount will be added to the customer charge. The remainder will be priced on the basis of 1996 energy usage so that the annual cost of electric service will be unchanged from the annual cost for 1996. PP&L St. 10, pp. 11-12; PP&L St. 9, p. 33; PP&L Exh. DAK 1.

In addition, Section 2806(h) of the Act specifically authorizes the Commission to approve flexible pricing and rates, "designed to meet the specific needs of a utility customer and to address competitive alternatives." The CRD would produce rate reductions for incremental usage over 1996 levels which will likely be the case for most customers. For example, GS-1 customers will see a 16% reduction in their marginal rate; GS-3 customers will see a 5% reduction; LP-4 customers will experience a 6% reduction; LP-5 customers will experience a 8.5% reduction; GH-1 customers will experience an 11% reduction; and GH-2 customers will experience a 13.5% reduction on incremental usage. St. 9, p. 33.

The CRD, in addition to providing beneficial rate reductions for incremental usage, represents a movement toward marginal cost pricing, enabling customers to make better informed energy usage decisions. The CRD also reduces the distortive effects of stranded cost collection on energy use while maintaining some continuity with present rates by moving only half of transition charges into fixed customer charges. PP&L St. 9, p. 6.

OCA has opposed the CRD as causing a shift of costs from customers with increasing usage to customers with decreasing usage and as being a less efficient rate design. OCA's basis for this contention is that the marginal cost of transmission and distribution costs can exceed embedded costs. OCA St. 4, pp. 15-16. OCA's concerns are groundless. Although PP&L's proposed CRD would recover less stranded cost from customers that increase energy usage, there is no prohibition against such a rate design in the Act. The Act's prohibition against shifting of stranded cost recovery between or within rate classes must be interpreted as applying to allocations based on historic levels of usage; otherwise only fixed CTCs would be permitted, and no party, including OCA has made such a proposal. OCA's contention, that the CRD shifts costs, is circular. It is correct only if one assumes that OCA's preferred traditional rate design is the only CTC rate design permitted under the Act; a comparison of the CRD with the traditional rate design is OCA's only support for its contention. OCA's presentation demonstrates only the obvious point that the traditional rate design and the CRD are different; it does not demonstrate that the traditional rate design is correct. In any event, since under PP&L's current proposal that all customers may chose the CTC rate design applicable to them, OCA's first concern vanishes.

OCA's second concern related to relative levels of incremental transmission costs and embedded costs is irrelevant. PP&L explained that it has no plans for substantial investments to expand its transmission system Tr. 825-26 (8/19/97). Regardless of any possible theoretical basis of OCA's concern, it has no practical significance in this proceeding. Although incremental transmission costs conceivably may exceed embedded costs, PP&L has no near-term incremental transmission costs. Therefore, PP&L's proposed CRD in fact presents a more efficient price structure, closer to marginal costs, than the traditional energy-related rate design.

B. Closure of Existing Economic Incentive Rates

PP&L presently offers a series of incentive rates that are designed, by various means, to promote economic growth in PP&L's service territory or to improve PP&L's load factor or both. These rates include riders and rate schedules and billing options. Riders include the Economic Development Incentive ("EDI") rider, the Industrial Development Incentive ("IDI") rider and the Competitive Rate Rider ("CRR"). Billing options available under certain rate schedules include demand free days and time of day ("TOD") billing options. Rate schedules include the Price Response Service, Rate Schedules PR-1 for firm service and PR-2 for interruptible service and Residential Thermal Storage ("RTS") service.

As explained in more detail below, PP&L's proposed treatment of these riders, billing options and rate schedules include three important features. First, PP&L proposes to extend the availability of these riders, billing options and rate schedules to customers presently served under them beyond the presently-scheduled termination date. Second, PP&L is proposing that the remaining incentive rates available to new customers be closed. Third, PP&L is proposing that customers under the incentive rate schedules remain eligible for a service under these incentive rates only if they use PP&L's BUS Service as their energy supplier.

Many of the incentive rates in PP&L's presently-effective tariff are scheduled to terminate in the relatively near future.[73] For example, the EDI and IDI rates are presently scheduled to be phased out in three steps commencing January 1, 1998 and to be totally eliminated as of January 1, 2000. PP&L St. 11, p. 8. Similarly, the Demand Free Days billing option is presently scheduled to terminate effective January 1, 1998. PP&L St. 11, pp. 10-11. PP&L's Price Response Services are scheduled to end December 31, 1997. PP&L St. 11, p. 13.

Despite the fact that these incentive rates, as a result of prior proceedings before the Commission, are scheduled to terminate in the near future, PP&L is proposing to continue these rate schedules, under which certain customers receive substantial benefits. The EDI and IDI rates will be continued to December 31, 2005 as will the Demand Free Days billing option. The Price Response Rate Schedules will be available until the customers becomes eligible for retail competition. PP&L St. 11, p. 14. The decision by PP&L to propose to continue these incentive rates is based upon PP&L's interpretation of the rate cap in Section 2804(4) of the Act. The language of the statute is not completely clear and contrary arguments can be made based on the fact that the PUC approved the phase-out of these incentive rates were approved prior to the passage of the Act. Nevertheless, the practical effect of phasing out these incentive rates would

---

[73] Because the date for Commission action in this case has been extended until June 4, 1998, PP&L obtained Commission permission to freeze these termination dates.

be that affected customers would pay more for service than they would pay if the incentive rates were continued.

PP&L proposes to limit the availability of incentive rates to customers presently served under them and using PP&L's BUS Service for energy supplies because all of these incentive rates were designed to increase utilization of PP&L's generation resources or improve the efficiency in use of PP&L's generation resources or both. PP&L St. 11-R, pp. 3-4, 8-9. The benefits of the incentive rates are not related to PP&L's delivery service. Instead, they are designed to benefit the provider of generation services. Any incentives or discounted rates should be offered by the energy providers, not the delivery service supplier. Discounting delivery service rates to improve utilization of generation facilities is a relic of vertically integrated utility service and bundled rates that makes no sense once a competitive retail electric energy market is established. PP&L proposes that the incentive rates be retained only for PP&L BUS Service customers.[74] In this way, to the extent that customers improve the load profile and utilization of BUS Service, thereby creating benefits that can be shared with other BUS customers of PP&L, PP&L will continue to make incentive rates available.[75] Otherwise, incentive rates are not proper and should not be included in delivery service rates.

Incentive rates should not be available to customers who temporarily use alternative competitive energy suppliers but return to PP&L's BUS Service. All of the incentive rates described here, except the CRR, are or soon will be closed to new customers. Under these

---

[74] It is important to note that use of PP&L's Retail Energy Marketing Group, instead of PP&L's BUS Service, would not qualify customers for participation in incentive rates. Therefore, PP&L's proposal does nothing to promote its competitive energy supplier vis-à-vis other competitive energy suppliers.

[75] There is one exception to the requirement to use BUS Service. Unlike the other incentive rates, the Competitive Rate Rider does not require use of PP&L's BUS Service. Discounts, however, are limited to delivery charges and the CTC. PP&L St. 11, pp. 11-12.

circumstances, the Act provides that any customer returning to BUS Service is to be treated as a new customer. Because new customers are not eligible for incentive rates, returning customers similarly are not eligible for these incentive rates under Section 2807(4) of the Act.

The Commission recently considered similar issues in PECO, at pp. 119-20. The Commission concluded that PECO was not required to continue to offer incentive rates to customers who choose alternative suppliers following expiration of existing contracts. PP&L's proposal is more favorable to customers than the Commission's Order in PECO. PP&L has proposed to extend the availability of most of these incentive rates through the end of the CTC application period to customers presently being served under incentive rates so long as they continue to use PP&L's BUS Service. The PECO Order would permit service under the incentive rates to terminate at the expiration of existing contracts.

C. Terms and Conditions Modifications to Existing Tariffs

Modifications to existing tariff rules, that are not addressed specifically elsewhere in this brief, are summarized in PP&L Sr. 11, pp. 17-18. These changes include the following:

- Rule 4 is changed to indicate that the Company may upon request supply services over and above those which the Company would normally provide, if the customer agrees to pay the Company a fair and non-discriminatory price for those related services.

- Rule 9E was changed to indicate that the Budget Billing interest rate is changed from the number 1% per month to one-twelfth of the average of 1-year Treasury Bills for the months of September, October, and November of the previous year.

In Tariff 201, changes include the following:

- Rule 6A has been amended to exclude fuel supply disruption from qualifying for backup power supply.

- Paragraph E(5) has been added to Rule 6A to indicate that a customer-specific, fixed, per month CTC developed by the Company, which will equal 100 percent of the customer's estimated CTC revenue, will be applied if the customer elects to install on-site generation on or after January 1, 1999.

Paragraph E(5) was based on Section 2808(a) of the Act, which permits recovery through a non-bypassable CTC of stranded costs from customers that install new on-site generation facilities. Under Section 2808(a), the CTC for such customer should be fixed and recover the customer's fully allocated share of stranded costs.

None of these tariff changes are controversial. All of the tariff changes summarized above should be approved by the Commission.

D. Allocation of Universal Service Charges

Section 2804(9) of the Act requires that the Commission provide for appropriate funding of universal service activities.

> The commission shall ensure that universal service and energy conservation policies, activities and services are appropriately funded and available in each electric distribution territory. Policies, activities and services under this paragraph shall be funded in each electric distribution territory by nonbypassable, competitively neutral cost-recovery mechanisms that fully recover the costs of universal service and energy conservation services. . . .

In this proceeding, PP&L has allocated its universal service costs on a customer basis. PP&: St. 3R, p. 36. This is consistent all the way in which such costs have been allocated in PP&L cost of service studies accepted previously by the Commission, including PP&L's most recent base-rate proceeding at Docket No. R-00943271.

OCA, in OCA St. 6-S, pp. 15-23 and OTS, in OTS St. 2, pp. 2-8, have recommended that the universal service charges be allocated on an energy, or per kWh, basis. Such contentions are inappropriate and should be rejected.

First, the Act expresses strong support for continuity of rates based on each electric distribution company's most recent base rate proceeding. For example, Section 2808(a) of the Act states, with regard to the CTC, that:

> The costs to be recovered shall be allocated to customer classes in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the electric utility's most recent base rate proceeding.

This strong policy in favor of continuity in ratemaking should be followed. The allocation of universal service costs on a customer basis, was approved in PP&L's most recent base-rate proceeding.

Further, because as explained previously, PP&L's stranded costs exceed maximum CTC revenues under the rate cap during the transition period, it is not possible to reallocate universal service costs without violating the rate cap applicable to customers that would receive a greater portion of universal service costs than would be allocated to them under PP&L's proposal.

OCA also provides an alternative allocator using non-production revenue as the basis for allocating universal service charges. OCA St. 6-R, pp. 20-22. Although this alternative proposal moderates slightly the effect of OCA's original proposal, it still suffers from the same deficiencies as OCA's original proposal to allocate universal service costs based upon energy or KWh usage and should be rejected for the same reasons.

OCA's proposals should be rejected for the additional reason that they were rejected in the PECO Order, page 146. There, the Commission concluded that universal service costs should be recovered from residential customers only, to be consistent with prior rate case determinations. Here, application of the principle that universal service costs are to be allocated in the manner determined in prior rate cases dictates that PP&L's proposal to recover such costs on a customer basis, which is more favorable to residential customers than the result in the PECO case, should be adopted.

E. Federal/State Jurisdictional Determination

The FERC has determined that it has jurisdiction over the transmission of electric energy in interstate commerce by a public utility. *See* Federal Power Act, 16 U.S.C. §§ 824 *et seq.* This Commission should not place Pennsylvania electric utilities in the position of having to chose between state and federal mandates. The Commission should ensure that all of its mandates do not intrude on the exclusive jurisdiction of FERC. The Commission can achieve all of the most important goals of restructuring while respecting the jurisdictional line that FERC has drawn.

In Order No. 888, FERC found that once retail service was unbundled, there would be a need to draw a distinction between facilities that are used for transmission and those used for local distribution because, in determining the extent and scope of its exclusive jurisdiction, FERC has concluded that it has jurisdiction of retail transmission in interstate commerce to the point of local distribution. Order No. 888, 61 Fed. Reg. at 21,627. FERC also stated that it would defer to state recommendations on where to draw the jurisdictional line, provided that state regulators specifically evaluate seven specific indicators and any other relevant facts and make recommendations consistent with the essential elements of Order No. 888.

PP&L has submitted such an evaluation in PP&L St. 12, pp. 17-20 and Exhibits WHW 1 and WHW 2. Although there is no clear line of demarcation between transmission facilities and local distribution facilities, FERC has adopted a list of seven indicators as a test for determining which facilities serve a distribution function. These indicators are:

1. Local distribution facilities are normally in close proximity to retail customers.

2. Local distribution facilities are primarily radial in character.

3. Power flows into local distribution systems; it rarely, if ever, flows out.

4. When power enters a local distribution system, it is not recognized or transported to some other market.

5. Power entering a local distribution system is consumed in a comparatively restricted geographical area.

6. Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.

7. Local distribution systems will be reduced voltage. PP&L St. 12, pp. 17-18.

In applying these tests, PP&L has concluded, subject to approval of this Commission and FERC, that its facilities operating at voltages of 69 kV and above are transmission facilities and facilities operating at less than 69 kV are local distribution facilities.

No party produced evidence contesting PP&L's analysis, and therefore, it appears not to be controversial. PP&L's conclusions should be adopted by the Commission.

F. Transmission and Distribution Unbundling

PP&L's proposed unbundling of delivery charges is summarized in PP&L St. 9-R. PP&L is proposing to unbundle its delivery charges into two principal categories, transmission and distribution. It is appropriate for the delivery charge to be divided in this manner so that retail customers can receive correct price signals resulting from taking power at different transmission voltages under alternative supply arrangements. Further, the unbundling of delivery charges into distribution and transmission charges is required under Section 2804(3) of the Act.

Transmission service, however, must be further unbundled. Retail access customers of PP&L will be required to utilize transmission services from PJM under the PJM Open Access Transmission Tariff. Customers will pay unbundled charges for transmission service and related ancillary services as specified in the PJM Open Access Transmission Tariff. The services will be identified and charges established by FERC.

OCA and OTS have contended erroneously that charges for universal service should be unbundled from distribution service charges as a separate line item on bills to customers. OCA St. 6, p. 45; OTS St. 3, p. 7. Such unbundling, however, would be inappropriate and would cause customer confusion. It is important to note that charges for universal service are "non-bypassable." 66 Pa. C.S. § 2804(9). Unbundling services on a customer's bill is appropriate only if the customer has some choice with regard to the unbundled expense. Customers cannot decline to pay charges for universal service; customers cannot obtain universal services from any other provider, at least through the end of the transition period. Consequently, there is no point to having charges for universal service unbundled into a separate billing line item. This conclusion is particularly true given the small amount of the per customer size of the universal service charge. It is far more appropriate to bring the universal service charges to customers' attention by means of a billing message , as proposed by the Company.. PP&L St. 10-R, p. 6..[76]

G. Other Rate Design Issues

PP&L proposed a rate mechanism for recovering the costs of supplying provier of last resort service to customers without hourly meters. That mechanism, the Purchase Generation Cost Rate ("PGCR"), would be patterned after the ECR; would be established on an annual basis; would be collected on a KWH basis; and would be reconciled for overcollections and undercollections. PP&L St. 3-R, pp. 39-41; PP&L Exh. JMK 7. The PGCR would include the market price of electricity purchased for last resort service customers and the costs of administering the Company's electricity procurement program. PP&L's proposal is fully consistent with Section 2807 (e)(3), which provides that the provider of last resort service shall

---

[76] PP&L addresses the further unbundling of delivery service charges in Section X.E. of this Brief, *infra*

acquire energy at "prevailing market prices" and recover "all reasonable costs."

The PGCR would not become effective until the end of the phase-in period. Unil that time, PP&L would continue to charge non-shopping customers its Commission-approved, tariffed rates. This approach is consistent with the Commission's orders in the PECO case. PECO Order, pp. 132-134; Order on Reconsideration, pp. 20-21.

The Company's proposal is consistent with the Act and the Commission's decision in PECO, and should be approved.

IX. PHASE-IN ISSUES

The Act mandates the following phase-in schedule for retail access:

> [T]he following schedule for phased implementation of retail access shall be adhered to unless a determination is made by the commission under subsection (c) [which allows for an additional six month transition period under certain circumstances]:
>
> (1) As of January 1, 1999, a maximum of 33% of the peak load of each customer class shall have the opportunity for direct access.
>
> (2) As of January 1, 2000, a maximum of 66% of the peak load of each customer class shall have the opportunity for direct access.
>
> (3) As of January 1, 2001, all customers of electric distribution companies in this Commonwealth shall have the opportunity for direct access.

66 Pa.C.S. § 2806(b). The Act gives the Commission specific instructions: "The time line for the transition to and phase-in of direct access to competitive electric generation shall be in accordance with section 2806." 66 Pa.C.S. § 2804(11).

A. Phase-in Selection Method

PP&L's proposed phase-in schedule tracks that mandated by the Act. As described in the testimony of Mr. Henry W. Baumann, PP&L Sts. 14 and 14-R, PP&L proposes an initial sign-up period for each phase-in period during which all customers interested in participating in competition can notify the Company. If any rate classes are over-subscribed, PP&L will conduct a random selection among customers seeking to participate. PP&L St. 14-R, p. 4. Enron, OSBA and PPLICA witnesses believe that this methodology should not apply to the selection commercial and industrial customers, based on the possibility that non-participating customers may suffer a competitive disadvantage over participating customers. *See* Enron St. 5.0, pp. 19-20; OSBA St. 1, pp. 51-52;. PPLICA St. 1, pp. 58-59.

PPLICA witness Stephen Baron asserts that the most appropriate methodology for selecting industrial customers is on a first-come, first-served basis, with the customer designating a desired level of load for participation. PPLICA St. 1, pp. 58-59. If there is an over-subscription of load, Mr. Baron proposes a pro-rata reduction to each subscriber's nominated load. To alleviate any remaining competitive disadvantages, Mr. Baron proposes that PP&L begin selection for the second phase and implement such a selection process by permitting retail access for up to 66% of peak load beginning January 2, 1999. PPLICA St. 1, p. 59.

Enron witness Mr. Bowen advocates a similar approach. Under Enron's proposal, Enron would be willing to accept the "first through the meter" approach, where Enron would supply the first portion of the customer's electricity received in a given hour and the EDC would supply the remainder. Enron would also be willing to "follow the customer's load" and provide a fixed percentage of its customers' load throughout the day. Enron St. 5.0, p. 20.

OSBA witness Robert Knecht suggests a variation on PPLICA's and Enron's approach to apply to commercial customers. He suggests that minimum levels of customer participation be set for the GS rate classes for each of two phase-in years. Under Mr. Knecht's proposal, if a rate class is over-subscribed and the random drawing produces too few customers, those few customers selected should be limited in the amount of their load that is subject to competition. OSBA St. 1, p. 53.

The Commission should reject these arguments. As discussed above, the phase-in schedule established under the Act is mandatory. The Act requires the Commission to establish regulations specifying that, within each customer class, the customers that are eligible for direct access during the phase-in period shall be determined by the Commission on a first-come, first-serve basis "unless otherwise determined by the commission . . . to prevent competitive disadvantages among similarly situated customers within a customer class." 66 Pa.C.S. § 2806(4). Neither Enron, OSBA nor PPLICA has made a showing of specific competitive disadvantage sufficient to justify a departure from the statutory presumption that the phase-in period will occur in the three stages established in Section 2806 on a first-come, first-served basis.[77] The Commission should reject the efforts of these intervenors to disrupt the "orderly" transition to a competitive generation market envisioned under Section 2806(14) of the Act, particularly in light of PP&L's express commitment to address any competitive problems on a case-by-case basis. PP&L St. 14, p. 5.

The Commission should also reject the various complex proposals for phasing in choice that would require customers to receive part of their service from their Alternative Supplier and part from their EDC. In the words of PP&L witness Dr. Tierney: "As a former regulator, I cannot imagine a phase-in proposal that would create more confusion among the public and more administrative difficulty for PP&L and the suppliers." PP&L St. 9-R, p. 50.

B. Grandfathering of Pilot Customers

Customers who are participating in the PP&L's pilot program can enroll in and will be selected for retail access as described above, with one exception. Customers who are

---

[77] Although the Commission found otherwise in *PECO*, PECO had already agreed to an accelerated phase-in schedule in its Partial Settlement. There is no settlement proposal in this case, nor does the record support a finding of competitive disadvantage, particularly for residential customers, who do not compete with each other. .

participating in PP&L's pilot program, but which are not selected for the first or second phase of retail access can elect to be "grandfathered" into retail access. However, customers in the Primary and Transmission/Subtransmission groups who have load limits in the pilot program will be limited to that level of load when "grandfathered" into retail access. PP&L St. 14, pp. 4-5. As discussed above, the intervenors have failed to provide record support that would justify a departure from this proposal.

X. CODE OF CONDUCT AND COMPETITION ISSUES

In its Restructuring Plan filing, PP&L announced a voluntary restructuring of its retail electric business and a Retail Access Code of Conduct. *See* PP&L St. 13-R, Exh. RMG-4. PP&L implemented it Retail Access Code of Conduct contemporaneously with the filing of its Restructuring Plan, as another manifestation of PP&L's strong support for the development of a healthy competitive market for retail electricity. Despite PP&L's demonstrated commitment to competition, several intervenors have submitted proposals designed to micromanage the competitive marketplace, handicap PP&L's efforts to compete in retail markets, and shield the new entrants from the very market pressures the General Assembly sought to invoke in adopting the Act. Such handicaps have no function in a truly competitive retail electric power market, and the Commission should reject them.

A. Purpose and Goal of Codes of Conduct and Competitive Access Rules

The Commission is charged under the Act with overseeing the development of a competitive retail electric generation market in a manner that treats both shareholders and customers fairly. Establishing standards of conduct to govern the relationship between electric distribution companies and their affiliated electric generation suppliers is an important part of ensuring that the competitive retail electric generation market will function in a way that fulfills the Acts directive to allow "electric generation suppliers and end-use customers to utilize and interconnect with the transmission and distribution system on a non-discriminatory basis at rates, terms, and conditions of service comparable to the transmission and distribution company's own use of the system to transport electricity from any generator of electricity to any end-use customer." 66 Pa.C.S.§ 2803.

The Commission is in the process of developing regulations concerning Customer Supplier Interaction at Docket No. M-00960890.F0011 and has opened a rulemaking to receive comments on the recommendations contained in the Final Report of the Competitive Safeguards Working Group ("CSWG").[78] PP&L proposes that the Code of Conduct set forth in the testimony of Robert M. Geneczko, PP&L St. 13-R, Exh. RMG-4, should govern the relationship between its EDC and EGS until regulations of general applicability are adopted.

As Dr. Kalt explained at the hearing, in addressing competitive safeguards the Commission has at least three options: (1) prevent extension of remaining monopoly power; (2) handicap utility affiliates; or (3) affirmatively support or subsidize rivals. PP&L St. 1-R, pp. 9-12. Only the first option, however, truly promotes and protects competition. As Dr. Kalt confirmed, "actions and advantages of the unregulated affiliates of an incumbent utility that should be regulated or eliminated are solely those that derive from leveraging of continued ownership and control of monopoly functions (i.e., transmission and distribution). Actions and advantages not so derived represent the tools of competition that the unregulated affiliates bring to non-monopoly marketplaces, and the consumer will be harmed if denied access to these." PP&L St. 1-R, pp. 9-10.

The second option, handicapping utility affiliates, will benefit competitors, but will harm consumer interests. Such handicaps would subject utility affiliates to complex and cumbersome

[78] The CSWG was formed in early 1977 to address the role and scope of competitive safeguards in a restructured retail electric generation market. The CSWG issued its Final Report to the Commission on October 6, 1997, which contains ten principles adopted by the working group. PP&L was a member of the CSWG and indicated its support for the ten principles by signing the Final Report.

reporting, operational, and compliance specifications not shared by their rivals and would result in the Commission promoting the interests of certain competitors, rather than competition itself. As PP&L witness Dr. Kahn warned:

> attempts by regulators—as distinguished from antitrust enforcement agencies—to handicap the process, to constrain some competitors from exercising whatever advantages they may have in terms of productive or marketing efficiency, customer goodwill, economies of scale or scope—however well-intentioned in terms of protecting individual competitors from unfair disadvantages—history tells us unequivocally—have an inherent tendency toward protectionism and cartelization, at the expense of the consuming public. The essence of deregulation is to remove all government barriers to free competition, leaving to the antitrust laws the prevention or removal of private barriers. PP&L St. 18-R, p. 6.

The third alternative, supporting or subsidizing PP&L affiliate rivals is, again, not in the best interests of consumers. For example, "marketing restrictions that raise the costs of the incumbent or deny the incumbent the use of assets that consumers value (such as brand name) are the functional equivalent of a subsidy to rivals, who do not have to bear such costs or build up such assets to remain competitive in the marketplace. This policy strategy is consistent with the interests of PP&L's rivals, but not the interests of consumers." PP&L St. 1-R, pp. 11-12.

Enron witness Mr. Dirmeier is simply wrong when he argues that: "My position does not handicap anyone; rather it is intended to place all competitors on the same initial footing, recognizing that, in reality, PP&L has a decided initial advantage that it seeks to prolong." Enron St. 6.1, p. 8. To make all competitors equal at the outset, the Commission would have to take into account the numerous inherent advantages and disadvantages of competitors, some based on efficiency and some based on basic cost differences. Such solutions would deprive customers of the benefits of more efficient producers. Instead, the Commission should adopt standards of conduct narrowly tailored to fulfill the purposes of the Act. If PP&L provides non-discriminatory access to regulated facilities, and does not engage in cross-subsidization or improper exchange of customer data, then any advantages it has in the marketplace derive from its ability to give consumers something they want.[79]

B. Existing Prohibitions on Anticompetitive or Discriminatory Behavior

Any additional protections required by the Commission should be considered in light of the pervasive safety net of competition protection that already exists. Existing antitrust laws, the Federal Power Act and the FERC's Order Nos. 888 and 889 contain numerous prohibitions on and protections against anticompetitive or discriminatory behavior. Moreover, Section 2811 of the Act gives the Commission the authority to monitor competitive conditions and conduct investigations.

1. Antitrust Laws

The Commission need not rewrite the antitrust laws in order to fulfill its mandate under the Act. The sole objective of the federal antitrust laws is to ensure a competitive economy. *United States v. South-Eastern Underwriters Ass'n,* 322 U.S. 533 (1944). The federal antitrust laws have, for over a century, focused on protecting fair competition in open markets.

The antitrust laws cover a wide variety of competitive injuries normally associated with the transition to competitive markets. These include the among others, prohibitions against tying, monopolizations, denial of reasonable access, monopoly leveraging and price fixing. Most importantly, however, antitrust enforcement agencies and the courts have extensive experience in balancing the procompetitive benefits of efficient operation against potential harm to competitors. *See Tenneco Gas v. F.E.R.C.,* 969 F.2d 1187, 1204 (D.C. Cir. 1992) ("[T]he Commission 'must also consider the extent to which various remedies would interfere with any

---

79 Neither the antitrust laws nor a workably competitive market require such a radical approach designed to handicap incumbents and subsidize new entrants. *See, e.g., Brown Shoe v. United States,* 370 U.S. 294, 320 (1962).

efficiencies that may stem from pipeline integration into marketing.' . . . 'The selection of a remedy . . . is thus a delicate balancing process involving the degree of competitive harm, the effectiveness of the remedy, and the competitive and administrative costs of the proposed remedy'").[80]

2. Federal Power Act

The Supreme Court has held that the FERC's regulatory mandate "clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations." *Gulf States Utilities Co. v. F.P.C.*, 411 U.S. 747, 758-60 (1973) ("*Gulf States*"); *see also F.P.C. v. Conway Corp.*, 426 U.S. 271, 279 (1976). This mandate has been held to include advancing the "fundamental national economic policy" of competition and economic efficiency expressed in the antitrust laws. *Gulf States,* 411 U.S. at 759.[81]

In a case frequently cited by the courts and the FERC for this proposition, *Northern Natural Gas Company v. F.P.C.*, the Court of Appeals held that "the basic goal of direct governmental regulation through administrative bodies and the goal of the indirect governmental regulation in the form of antitrust law is the same — to achieve the most efficient allocation of resources possible." 399 F.2d 953, 959 (D.C. Cir. 1968). Indeed, the Supreme Court has observed:

---

80 The Court quoted approvingly from the comments of the United States Department of Justice and the Federal Trade Commission submitted in Response to the Notice of Inquiry into Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, F.E.R.C. Stats. and Regs, Regulations Preambles 1986-1990 ¶ 35,520 (1986).

81 Under the Federal Power Act, the obligation of utilities not to discriminate exceeds the burdens imposed by the antitrust laws on firms acting unilaterally. Thus, under Section 205 of the FPA, public utilities have an affirmative obligation not to "make or grant any undue preference or advantage" or to "maintain any unreasonable difference" in rates, practices, or facilities. 16 U.S.C. § 824c(b). Similarly, under Section 212, rates, charges, terms, and conditions for transmission ordered under Section 211 shall not be "unduly discriminatory or preferential." 16 U.S.C. § 824k(a) (Supp. 1995).

> Consideration of antitrust and anticompetitive issues by the Commission, moreover, serves the important function of establishing a first line of defense against those competitive practices that might later be the subject of antitrust proceedings.

Gulf States, 411 U.S. at 760.

3. FERC Order Nos. 888 and 889

In Order No. 888, the FERC required all public utilities that own, control or operate transmission facilities to file open access transmission tariffs, to take transmission service for their own new wholesale sales and purchases under those tariffs, to develop and maintain a same-time information system to give all transmission users the same access to transmission information that the public utility enjoys and to separate transmission from wholesale merchant functions and communication. The FERC required utilities in Order No. 889 to adopt standards of conduct designed to functionally separate transmission and wholesale merchant functions and to prevent transmission providers from giving their wholesale merchant counterparts within the public utility an undue preference over their customers though the exchange of "insider" information between the company's system operators and employees of the public utility, or any affiliate, engaged in wholesale merchant functions. *See* 18 C.F.R. § 37.4. PP&L plans to extend its Order No. 889 Code of Conduct to its retail transmission operations. PP&L St. 13, p. 5.

C. Basis and Extent of PP&L's Proposed Code of Conduct

PP&L's proposed Code of Conduct will govern the relationship between PP&L's Generation Supply Group and its the Electric Delivery Group.[82] The Code of Conduct is intended to control dissemination of confidential customer information; restrict access to

---

[82] At the time of the hearing, PP&L had not yet determined the names under which its Electric Delivery Group and Generation Supply Group will do business. PP&L's Electric Delivery Group is now doing business as "PP&L Access," and PP&L's Generation Supply Group is marketing energy to wholesale and retail customers under the name "PP&L Energy Plus."

competitive information; prevent cross-subsidies between regulated and unregulated operations; and prevent discriminatory practices. It is designed to ensure that employees of the Electric Delivery Group engaged in transmission system operations function independently of the Generation Supply Group employees who are engaged in the purchase and sale of electric energy, in order to ensure that the Electric Delivery Group does not use its access to information about transmission to benefit unfairly its own or the Electric Generation Group's sales.

PP&L's proposed Code of Conduct is set forth in PP&L Exhs. RMG 2 and RMG 4; it is discussed in PP&L St. 13-R. PP&L envisions that this Code of Conduct will remain in effect until such time as the Commission adopts regulations establishing permanent standards of conduct. PP&L's proposed Code of Conduct tracks the principles adopted by the Competitive Safeguards Working Group. Specifically, the Retail Access Code of Conduct provides for:

- Open, Non-Discriminatory Access to and Pricing of Regulated Monopoly Services (PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, pp. 1-2).
- Prohibitions on Conditioning (Tying) of Access to Monopoly Services on Purchase from Generation Supply (PP&L Exh. RMG 2, pp. 4-5; PP&L Exh. RMG 4, p. 2).
- Non-Discriminatory Dissemination of Disclosed Market and Competitively Sensitive Information (PP&L Exh. RMG 2, pp. 3-5).
- Confidentiality of Customer and Supplier Information (PP&L Exh. RMG 2, p. 4; PP&L Exh. RMG 4, p. 1).
- Segregation of Personnel and Information by Group (PP&L Exh. RMG 2, p. 1; PP&L Exh. RMG 4, p. 1).
- Restriction of Information Transfer Via Personnel Assignment (PP&L Exh. RMG 2, pp. 2-3; PP&L Exh. RMG 4, p. 1).
- Separate Cost Allocation, Books, and Records (PP&L Exh. RMG 2, p.5; PP&L Exh. RMG 3, p. 2).
- Enforcement of Employee Education in the Codes of Conduct (PP&L Exh. RMG 2, pp. 5-6; PP&L Exh. RMG 3, p. 2).

- Compliance Reporting, Auditing and Dispute Resolution (PP&L Exh. RMG 2, p. 6; PP&L Exh. RMG 3, p. 2).

These rules and protections will assure a fair and open market without unfairly handicapping PP&L as a competitor.[83]

D. Additional Competitive Restrictions Proposed

1. Prohibit Use of "PP&L" Name

Mr. Dirmeier would have the Commission believe that Enron faces a Herculean task overcoming the single brand of PP&L. Enron St. 6.1, p. 2. Similarly, Mr. Dirmeier claims that although it is possible that some entrants will find advantages of their own, overcoming the name and goodwill advantages of the incumbent EDCs will be daunting at best. Enron St. 6.1, p. 9.

This argument simply is not correct. Enron and many other potential competitors have a strong market presence and have the resources to overcome the single brand name of PP&L.[84] To date, [more than thirty] firms are licensed to be alternate retail suppliers under the Act.[85] The list of licensed generation suppliers includes companies with considerable experience and success in unregulated markets or in markets with partial deregulation. PP&L's potential competitors

---

83 PP&L has chosen not to include Subsections (1) - (6) as listed in the "Code of Conduct" section of the common briefing outline adopted in this case. The relevant provisions of PP&L's Code of Conduct are referenced in the bullet points above and throughout the remainder of this section.

84 Enron has a significant, national market presence. Enron advertised during the Super Bowl telecast in January 1997 and has been advertising its brand name heavily throughout the country. Enron witness Mr. Shapiro stated that one of Enron express corporate objectives is to become the premier seller of electric energy at retail in the United States. Tr. 1605 (8/26/97). Mr. Shapiro agreed at the hearing that Enron is taking steps that any competitor would in trying to break into new market. Tr. 1605-06 (8/26/97). For example, Mr. Shapiro admitted that "It is very likely that one of the products that we will try to bring into the marketplace is a lower priced product than our other competitors." Tr. 1607 (8/26/97).

85 In addition, 89 firms have registered as members of PJM, with the reasonable presumption being that most of them have intentions of participating in the marketplace in which PP&L will operate.

include numerous other vertically integrated utilities based in other jurisdictions, independent power producers and marketers, energy service firms such as Enron, and retailing companies such as American Express that have expressed interest in entering electricity markets[86].

a) The use of the name "PP&L" by the Generation Supply Group will not lead to customer confusion.

Enron witness Mr. Dirmeier asserts that PP&L's proposed Code of Conduct would lead to customer confusion because it does not go far enough to prevent PP&L's non-regulated operations from using the name of the EDC in a manner in which customers could reasonably imply that the electric generation supply is being provided by PP&L as the EDC rather than PP&L as the electric generation supplier. Enron St. 6.0 , p. 31-33; *see also* Enron St. 6.1, pp. 1-

.

Mr. Dirmeier is incorrect. There will be no customer confusion under PP&L's proposal by the use of the name "PP&L Energy Plus" because as described above, by Mr. Geneczko, PP&L will clearly and explicitly distinguish delivery service and generation supply service as separate operations. Tr. 553 (8/18/97).

Moreover, *prohibiting* PP&L's Generation Supply Group from using the PP&L name will lead to customer confusion and may deceive customers. Dr. Kalt put this succinctly at the hearing:

> It is inappropriate to in any way deceive consumers and imply that they are not getting service from some company. Taking information out of a market is not plausibly a sound public policy. The reason for that, as I have said, is that information to consumers is valuable because they value such things as peace of mind, assurance, et cetera, reputation.

---

86 The Commission in the PECO Order did not prohibit PECO's competitive affiliates from using PECO's name. PECO at 131.

Tr. 459 (8/18/97). Enron witness Mr. Dirmeier acknowledged that it would it be wrong to mislead customers as to who is providing their power. Tr. 687 (8/19/97). As recognized by Mr. Dirmeier, a name benefits consumers by providing information and assurance. Tr. 439 (8/18/97). Mandating the use of a different name would deprive consumers of the added assurance of quality and price derived from putting the parent's reputation at stake.

b) PP&L's Name is a Shareholder Asset.

The name PP&L and the good reputation associated with the name are shareholder assets, and, as such, are not included in the ratebase. The name and reputation of a utility therefore are not assets to which ratepayers have a claim. Ratepayers have never had to pay through rates a return on the value of goodwill or for enhancement of the utility's name, and name and reputation are cost free to PP&L's customers. Thus, there is no ratepayer harm in allowing PP&L to continue to use its name, or in allowing its affiliate to use the name.

PP&L's name <u>and</u> reputation do not, as Mr. Dirmeier claims, "result [from] its providing regulated monopoly service under the quality service guidelines established, in this jurisdiction, by the Pennsylvania Public Utility Commission[.]" Enron St. 6.1, p. 10. Indeed, whether a utility's brand name is a good one or a bad one is not a function of utility assets. If that were true, all regulated utilities in the United States would have good reputations.[87] As Dr. Kalt stated:

> We're all aware that some utilities around the country have good brand names, some of them have real bad brand names. And that fact suggests, of course, that it's not a function of their ownership of essential facilities, T & D, the natural

---

[87] Mr. Dirmeier agreed that some utilities do not have good reputations with their customers. Tr. 688 (8/19/97).

monopoly function that's generating the brand name. Otherwise they'd all have great brand names. . . . I think you cannot conclude that the good brand name's a function of the natural monopoly attributes or just a fact of regulation over the last 75 years. Tr. 518 (8/18/97).

c) Prohibiting the Use of the PP&L Name is Anti-Competitive and Will Harm Consumers.

The various ways in which firms distinguish themselves and the advantages that certain firms have over others in a competitive market benefit consumers because they allow the firm which possesses them to deliver something that consumers want, or to deliver what consumers want on better terms. These advantages and distinctions may arise through luck, savvy, or history. Firms' distinguishing characteristics may include brand names that are well-respected, convenient locations that reduce transportation costs or a base of potential customers encountered in related markets. The process of rivals each trying to find their own advantages and overcome the advantages of their competitors is what allows consumers to "win." PP&L St. 1-R, p. 14. The Act, like the antitrust laws, does not mandate that all such advantages and disadvantages be leveled. It was not designed to be an assistance program for disadvantaged competitors. *See, e.g., United States v. Syufy,* 903 F.2d 659, 668 (9th Cir. 1990); *Olympia Equip. Leasing Co. v. Western Union Tel. Co.*, 797 F.2d 370, 374 (7th Cir. 1986).

d) It is Not Appropriate For the Electric Generation Supply Group to Have to Pay a Royalty or Fee to Use Its Name.

Enron witness Mr. Dirmeier asserts that if there is value in PP&L's name, then the name should not be conferred without compensation. Enron St. 6.0, pp. 28-29, Enron St. 6.1, pp. 10-11. The payment of a royalty is inappropriate for several reasons. First the utility's name is not a ratepayer asset, as discussed above. Requiring PP&L's Generation Supply Group to pay a royalty for the use of the PP&L name would constitute a taking without just compensation. The imposition of a royalty would constitute a requirement that a regulated company dedicate its intangible assets, for which ratepayers have never paid and do not own, to the ratepaying public.

Second, a percentage royalty, which is one type of royalty that has been proposed in other jurisdictions, does not bear any relationship to costs or benefits from the association of the affiliate with the utility and would be difficult if not impossible to value. It is also questionable whether the Commission has the authority to require an unregulated, private business to pay a royalty to affiliated utilities' ratepayers. Such an order may be an improper extension of ratemaking authority. Absent a showing that ratepayers will be charged an unreasonable cost for service as a result of a transaction between a regulated company and its affiliate, the Commission does not have the authority to order a regulated company to charge its affiliate for benefits allegedly conferred on the affiliate as a result of its relationship with the regulated company.

2. Ancillary Services

Several parties, including Enron, *See* Enron St. 3.0, that in addition to revenue cycle services, ancillary services also should be unbundled. These proposals are not only beyond the intent of the Act, they are beyond the Commission's jurisdiction as well. Ancillary services are services offered in connection with the transmission of electric power. They are clearly transmission-related not distribution-related services. As such, they are within the exclusive jurisdiction of the FERC. *See* Section X.D.4. Indeed, the FERC unbundled anciallary services in Order No. 888.

3. Prohibit Joint Marketing

PP&L's proposed Code of Conduct provides that the Electric Delivery Group will not favor the Generation Supply group in any marketing of energy supply products. In addition, PP&L witness Mr. Geneczko agreed during the hearing that PP&L's Generation Supply Group will have access to bill inserts on the same terms and conditions as other electric generation suppliers. Tr. 586 (8/18/97).

As clarified by Mr. Geneczko at the hearing, PP&L's Electric Delivery group may engage in joint marketing of energy supply products with PP&L's Generation Supply group, but will only do so as long as comparable opportunities are available to other suppliers and the purpose of the joint effort is economic development. Tr. 554 (8/18/97). The Electric Delivery group still has an interest and community responsibility to facilitate economic development, but is indifferent, however, as to which alternate suppliers provide the energy part of the package. PP&L St. 13-R, p. 24. It will inform alternative suppliers of any such arrangements on a "rather immediate" basis, which may include posting such arrangements on OASIS. Tr. 583 (8/18/97).

4. Require that Surplus Power Be Offered to Alternate Suppliers

Several intervenors suggested that PP&L should be required to offer any surplus power to Alternate Suppliers. Enron St. 6.0, p. 37. Such a requirement would be a drastic intrusion into the competitive process that the Act has determined "will no longer be regulated . . ." 66 Pa.C.S. § 2802(14). Moreover, such a requirement would clearly be beyond the Commission's jurisdiction. The sale of surplus power to Alternate Suppliers is a wholesale transaction that falls squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1). *Federal Power Comm'n. v. Southern California Edison Co.*, 376 U.S. 205, 216 (1964) (FERC jurisdiction is plenary and extends to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States). *See also Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 53 (1986); *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 374 (1988). The fact that power will ultimately be used to serve retail customers does not change the wholesale nature of the transaction. *Pacific Gas and Elec. Co.*, 77 FERC ¶ 61,265 at 62,088 n.43 (1996).

5. Require the Delivery Group to Make Non-Delivery System Information Available to All Alternate Suppliers

Enron witness Mr. Dirmeier suggests the need for an internet bulletin board to document *all* information shared between the Electric Delivery Group and the Generation Supply Group.

This recommendation is far too broad and is not supported by any provision in the Act. As explained in Mr. Geneczko's rebuttal testimony, Company personnel necessarily will meet from time to time to discuss matters of a corporate nature, such as personnel, or matters relating to joint work outside of the Electric Delivery group's service territory. Much of the information discussed in these meetings is confidential in nature, the sharing of which is not necessary to achieve a competitive retail electric generation market. PP&L St. 13-R, p. 15. Thus there is no reason or authority for the Commission to address such non-delivery information in this proceeding.

6. Prohibit Market-Driven Contracts Before Choice is Implemented

Enron has proposed that in the time before direct access begins to be phased in, PP&L should not be permitted to enter into "market priced" contracts unless PP&L first offers to competitive suppliers the opportunity to bid to provide service to the customer and that customers who entered into such contracts subsequent to the date on which the Act was passed to cancel such contract. Enron St. 6.0, p. 46. Mr. Dirmeier admits that he has no information that would lead him to believe that PP&L is engaging in the behavior he would prohibit.

As discussed by Mr. Kalt in his rebuttal testimony, requesting the Commission to "open up" pre-existing market-based contract is a transparent attempt to gain Commission intervention in competitive market to favor PP&L's competitors. As explained by Dr. Kalt,

> long term contracting is a mechanism by which customers -- particularly the relatively large and sophisticated kinds of customers commonly seeking long term contracts -- can visit the force of impending competition on a utility's electricity sales even before the commencement of choice. The reason is obvious: the pending opening of choice can enhance the bargaining position of a utility's customers regarding price, length of contract, and other terms and conditions. The presence of choice on the near horizon enables customers to credibly threaten to take only standard tariffed service and/or insist on near-term termination rights that would enable them to depart for other suppliers upon the start of choice.

> In short, customers are better off having the option of signing long term purchase contracts with a utility in the face of pending open access than they would be if their only option were to stay with a utility's standard tariffed service and exercise choice upon a future date. It is understandable that rivals would like to expand the number of customers they can chase upon the opening of access, but it is not in customers' interests nor does competition require that customers be required to wait for access in order to realize some of its benefits. PP&L St. 1-R, pp. 51-52.

7. Require a Uniform State-Wide Code of Conduct

As discussed above, PP&L supports the Commission's effort to adopt uniform, state-wide standards of conduct. Until those standards are adopted, however, PP&L believes that its proposed Code of Conduct should govern the relationship between its Electric Delivery Group and Generation Supply Group.

8. Require PP&L to Permit Alternate Suppliers to Bill for Distribution Services and Be the Sole Contact for Customer Service

The Commission currently permits two billing options: (1) the EDC will provide a bill for all basic services to customers who have not chosen a generation supplier and those who have chosen a generation supplier but asked to receive a single bill; and (2) the EDC will provide a bill for all basic services except generation to customers who have chosen a generation supplier but asked to receive separate bills from the supplier. As explained below, consideration of a "third" billing option, permitting alternate suppliers to bill for distribution services should await the forthcoming Commission rulemaking.

9. Limitations on the Provision of Non-Utility Services

Several intervenors have raised concerns over the plan of PP&L's Electric Delivery Group to continue marketing products such as electronic thermostats, Power Watch™ devices and Heat Comfort™ controls. *See* Enron St. 6.0, p. 18; Tr. 570 (8/18/97). These concerns are misplaced. Prohibiting the EDC from providing these services is not required under the Act, and is by no means a prerequisite to carrying out the primary purpose of the Act – "to permit retail customers to have access to a competitive *generation* market as long as safe and affordable transmission and distribution service is available" at current levels of reliability. 66 Pa.C.S. § 2802(3). There is no indication that the General Assembly had a concern with utility involvement in non-generation products and services, as long as customers have fair and non-discriminatory access to a competitive generation market and competitive suppliers of electricity.

E. Further Unbundling of Distribution Rates or Services

1. Metering, Billing and Collection Services

Several intervenors have argued in this proceeding that customer metering and billing services should be unbundled from other EDC customer services in order to create an additional opportunity to provide value-added services to consumers. *See* Enron St. 4.0, p. 3. As noted by the Commission in the PECO Order, the Commission has addressed these issues through various working groups, rulemakings and Orders. Although section 2804(3) of the Act provides that "the Commission may require the unbundling of other services" in addition to basic unbundling of transmission, distribution, and generation services, the Commission concluded in the PECO Order that Section 2807 of the Act, which sets forth the duties of electric distribution companies, does not assume that any additional unbundling is required and that "EDC's continue to have the duty to provide all distribution services, including metering and billing, in compliance with existing Commission requirements." PECO Order at 138-39. The record established in this proceeding mandates the same conclusion.

a) Customer Billing

Several of the intervenors have argued that a customer should be able to receive a single bill from its EGS that includes EDC charges. *See* Enron St. 5.0, pp. 6-7. Section 2807(c) of the Act provides that the EDC may be responsible for billing customers for all electric services but grants the customer the right to choose to receive a separate bill from its generation supplier. The Act itself explicitly specifies a presumption that the EDC shall have the duty to provide a single bill, including competitive generation services, to all customers unless the customer chooses to receive a separate bill directly from its EGS. The Commission has initiated a rulemaking to address the manner and details of the interaction between customers, suppliers, and EDCs at Docket No. M-00960890.F0011.

The Commission recognized in the PECO Order that there may be potential benefits of such proposals but concluded that it is inappropriate to unbundle billing based on the record presented in that proceeding. The Commission directed PECO to provide all billing services, including billing for generation services, unless a customer indicates a preference to receive a separate bill directly from the supplier for generation services. PECO Order at 139. The record in this proceeding mandates the same conclusion.

b) Metering

As indicated the Commission's rulemaking at Docket No. L-00970120, the Commission has decided that it is unnecessary to unbundle metering as a competitive service at this time. In that rulemaking, the Commission outlined the standards and procedures to ensure that customers have real options for competitive metering while retaining all physical work related to metering as a regulated EDC function.

The Commission decided in the PECO Order that all customers may, in conjunction with their EGS, request use of a "qualified meter" that has been approved by the Commission based on the recommendations of a working committee composed of interested parties. The Commission will ensure that the list of qualified meters includes all meters necessary to support market services such as two-way communication, remote readings, time-of-use capability, and net metering. As discussed below, PP&L supports this option.

2. Require Delivery Group to Supply Customers Not Eligible to Choose Alternate Suppliers During the Phase-In.

Various parties asserted that PP&L had decided that customers not yet eligilble to choose would be served by its competitive generation supplier during the phase-in period. However, as PP&L explained, customers not yet eligible to choose would be served under traditional regulated rates. Tr. 743 (8/19/97). This treatment is consistent wiht the PECO Order, pp. 132-134; Order on Reconsideration, pp. 20-21.

F. "Open Architecture" Standards for Metering and Other Distribution Services

PP&L witness Anthony M. Osmanski indicated PP&L's support for open system architecture for all metering services hardware and software. PP&L St. 21-R, p. 3. PP&L advocates the use of the standards currently being developed by the IEEE SCC-31 Standards Coordinating Committee. *Id.* PP&L believes that the installation of the actual metering hardware should remain part of the regulated distribution services. The energy information exchange would be provided as a "Standardized and Open Architecture" data stream to a customer interface. This interface gateway should be the marketable product open to competition, providing a receptacle for data and a gateway to communication and information services. The market may be driven to provide this information service with no initial cost to the customer. PP&L St. 21-R, p. 12.

G. Treatment of Partial Payments by Customers

Enron witness Raymond W. Bowen, Jr. suggests that payments received from customers by PP&L should be applied to services provided by PP&L and services provided by the supplier on a pro rata basis. Enron St. 5.0, pp. 16-17.

As Mr. Bowen acknowledged at the hearing, however, if payments are provided to the supplier on a pro rata basis, the amount of the EDC's non-recovery will increase. Tr. 1339-40 (8/22/97). Despite this fact, Mr. Bowen asserts, without foundation, that an increase in the amount of the EDC's non-recovery would not increase the EDC's cost of providing service. *Id.*

The Commission has already considered and rejected the pro rata payment approach advocated by Enron. *See* Final Order Re: Guidelines for Maintaining Customer Services at the Same Level of Quality Pursuant to 66 Pa. C.S. § 2807(D), and Assuring Conformance with 52 Pa. Code Chapter 56 Pursuant to 66 Pa. C.S. § 2809(E) and (F) (entered July 11, 1997). Instead, the Commission decided that the "priority" method of applying partial payments is preferable to the "prorata" method, particularly in terms of administering the process and complying with applicable Chapter 56 provisions at 52 Pa. Code §§ 56.23 and 56.24. Order at 32-33.

H. Allocation of PJM Intertie Capacity

Enron witness Richard D. Tabors urges the Commission to require PP&L to make its PJM-allocated intertie benefits available to either its former retail customers who choose an alternative generation supplier or to that customer's supplier. Enron St. 8.0, p. 3. The relief requested by Enron, however, is beyond the scope of the Commission's jurisdiction, power and authority.

It is well-established that the rates, terms and conditions of wholesales sales of power by public utilities fall squarely within the FERC's exclusive jurisdiction under the Federal Power Act ("FPA"). Section 201 of the FPA gives the FERC plenary, exclusive and non-delegable jurisdiction over such sales. 16 U.S.C. § 824(b)(1). *See, e.g., Mississippi Power & Light Co. v. Mississippi*, 487 U.S. at 374. Indeed the FERC considered the very issue in its recent order on the restructuring of the PJM Interconnection. *See Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶ 61,257 (1997).

I. Customer "Slamming"

Section 2807(d) of the Act requires the Commission to promulgate regulations to ensure that customer consent is obtained prior to a change of electric suppliers. The Act allows an authorized change to be initiated once an EDC has received direct oral confirmation from the customer or written evidence of the customer's consent. The Commission issued a Proposed

Rulemaking Order Establishing the Standards for Changing A Customer's Electric Supplier at Docket No. L-00970121 in April 1997, which provides that a change of a customer's supplier may be initiated once the EDC has received direct oral confirmation from the customer or written evidence of the customer's consent. Under the proposed rules, "written evidence of the customer's consent" is limited to a document signed by the customer, the sole purpose of which is to initiate a change of electric suppliers.

Enron witness Mr. Bowen believes that the "written evidence" requirement should not require "direct" written communications from the customer through a letter of authorization or an agency agreement, nor should it require that the customer execute the document submitted to the EDC. Rather, Enron believes that "written evidence of the customer's request" should include any document which evidences to the EDC that customer consent was received by the supplier. Enron St. 5.0, p.24.

PP&L disagrees with this approach and continues to believe that incidences of slamming will be minimized if the customer is directly involved in the process. Tr. 1236 (8/21/97). PP&L's proposal accomplishes the same goal as the Commission's proposed regulations—to ensure that a customer consents to the switching of its generation supplier. Under PP&L's proposal, an alternative supplier may provide written notification to PP&L of a customer's decision to purchase electricity from that alternative supplier. The Company will then send the supplier's written notification to the customer and request that the customer inform the Company if any of the information is incorrect or inaccurate. If the customer does not respond, the Company will assume the supplier's notification information is correct. PP&L St. 14, p.6.

XI. CUSTOMER EDUCATION

PP&L's Customer Choice Education Program ("CCEP") is clearly focused on carefully developing and providing customers with educational information that will give them the information they need to make informed choices. As explained by PP&L's witness, Dawn G. Lennon, the key principles of PP&L's CCEP are:

- PP&L will provide clear, balanced and practical explanations of what customer choice is, how it works, what the risks and trade offs are, and how to select an electricity supplier.

- PP&L will be recognized as a consistent, reliable and trustworthy source of information on customer choice.

- PP&L will separate customer choice education efforts from sales and marketing initiatives.

- PP&L will produce customer choice educational materials which are easy to read and understand and which meet high standards of objectivity.

- PP&L will pursue partnerships with the Commission and with educational, service, and consumer organizations in the development, implementation, dissemination, and evaluation of educational materials and programs on customer choice.

- PP&L will continue its customer choice education efforts to address new needs and changes, ensure understanding, and provide ongoing support for customers.

PP&L St. 17, pp. 4-5. PP&L's CCEP includes reliance on community based organizations ("CBOs") and other stakeholder groups to assist PP&L in its education efforts.

PP&L's Customer Choice Handbook is the centerpiece of its CCEP. It will include an overview of the restructuring of the electric utility industry, an explanation of customer choice and how it works, consumer protection tips, worksheets for determining the customer's choice of suppliers and answers to important questions about the retail access market place.

In addition to the Handbook, PP&L will offer interactive telephone technology and presentations by customer choice educators. PP&L will sponsor a Customer Choice Education Advisory Committee composed of leaders from consumer, education and community organizations to oversee the development of customer choice educational workshops for target groups. The group will develop the details of the consumer education plan, commission the development of materials, design the methods of dissemination, analyze evaluation research on the program and ensure that PP&L's consumer education program provides balanced and unbiased knowledge to customers.

A. Statewide Customer Education Program

PP&L's CCEP is designed to be implemented on a local level by PP&L and various community based organizations. Nevertheless, PP&L will support and actively participate in a statewide effort if the Commission ultimately determines that such an effort is appropriate. As Ms. Lennon emphasized, however, a statewide effort alone cannot effectively educate customers. PP&L St. 9-R, p. 48.

As suggested by OCA witness Barbara Alexander, individual market participants should supplement any statewide effort with their own customer education activities. OCA St. 5, p. 17. It is not only appropriate to allow and encourage the various market participants to play a role in informing consumers, but it is also not realistic to bar PP&L — or others — from distributing information to their existing and potential customers. PP&L strongly disagrees with Enron witness Mr. Bowen's recommendation that the Commission or an independent third party under the Commission's supervision prepare and distribute educational information on a centralized basis. Enron St. 5, p. 28-29. While a Commission-led customer education program can be part of a successful education campaign, it cannot substitute for local customer education programs, which are best developed and implemented on a service territory by service territory basis.

Moreover, PP&L has an obligation under the Act to provide balanced unbiased information from which customers can make an informed decision to exercise choice. Specifically, Section 2807(d)(2) of the Act requires each EDC to provide adequate and accurate customer information to enable customers to make informed choices. Section 2807(d)(3) of the Act further directs the Commission and each electric distribution company to implement a consumer education program informing customers of the changes in the electric utility industry prior to the implementation of any restructuring plan.

The Commission recently initiated a proceeding regarding the Creation and Implementation of a Statewide Consumer Education Program for Electric Restructuring in the Commonwealth of Pennsylvania, Docket No. M-00981036 (entered Jan. 16, 1998). In its Order, the Commission solicited comments on a comprehensive consumer education program which will include a statewide media campaign and a local community initiative. As the Commission recognized, "[p]articipation in a statewide media campaign or the use of CBOs on a local level does not eliminate the requirement that the EDCs actively participate in the comprehensive consumer education program at the local level." Order at 7.

PP&L continues to believe that the most useful tools to educate are reference materials (print, audio and website) that customers can access and revisit. While the use of mass media can be an effective tool to create customer awareness, it must be followed by information such as brochures, pamphlets, direct mail and other forms of communication to expand the "soundbite" messages of a media campaign. The best way to educate is to mobilize and equip people in the community using community-based organizations. Tr. 2009 (8/29/97).

B. Specific Milestones and Budgets

PP&L provided the OCA with a five year preliminary budget for its CCEP. PP&L St. 17-R, Exh. DGL-2. This budget will allow PP&L to meet the stated objectives of its CCEP. Any statewide consumer education program should be developed in an orderly and logical manner. Specifically, the program details and components should be designed before the budget for statewide activities in established, not vice versa. It simply does not make sense to set a budget and then develop programs to utilize the allocated funds.

C. Customer Research

PP&L 's CCEP is based on extensive customer research. PP&L St. 17-R, p. 5-6. Based upon input from a variety of stakeholders, including the results of an independent customer research project, PP&L is revising its Customer Choice Handbook to provide education to consumers as the phase-in of full retail competition begins. Tr. 1974 (8/29/97).

D. Evaluation of Customer Education Efforts

PP&L is committed to conducting a full evaluation of its CCEP. Evaluation of PP&L's overall education efforts will be ongoing throughout the transition to retail competition. PP&L St. 17, p. 7. PP&L's research will continue to focus on what customers know and understand about choice, the best vehicles for obtaining this information, the most credible sources of information, the usage profile and related demographics. Customers already surveyed will continue to be surveyed and compared to new customers. PP&L will share this information with the Commission.

E. Separation of Education from Marketing Activities

Separation of PP&L's CCEP and its communications and marketing efforts is one of the key principles of PP&L's proposal. PP&L will not use its CCEP to market competitive business products. PP&L St. 15-R, p. 22. Its education efforts will not favor one supplier of energy or capacity over another. PP&L St. 17-R, p. 22-23. Customer choice education initiatives will be managed by the Company's Customer Services department and customer information will be managed by Corporate Communications department. PP&L's marketing activities will seek to promote products and services through either its Delivery Services & Economic Development department or through its Generation Supply Group.

Enron witness Mr. Bowen suggests that PP&L's name should not appear on customer education communications. Enron St. 5, p. 31. As stated by Ms. Lennon: "To develop and disseminate consumer education materials and not to put the Company name on them would be deceptive. Consumers are entitled to know where any materials come from so they can ascertain for themselves whether or not to accept the messages in them." PP&L St. 17-R, p. 23.[88]

XII. Universal Service and Customer Assistance Programs

PP&L has been among the industry leaders in implementing programs to address customer and community needs, especially those of low-income customers. In 1996, the Company's annual funding level for universal service programs and energy conservation programs was over $7 million. The Company has reviewed its existing programs and concluded that it must continue its leadership role in this area. As outlined in the testimony, of Timothy R. Dahl, PP&L plans to increase its annual funding for universal service programs and energy conservation programs from a current level of $7 million to approximately $14.3 million by the year 2002. PP&L St. 16, p. 4.

Section 2802(10) of the Act provides that "the commonwealth must at a minimum, continue the protections, policies and services that now assist customers who are low-income to afford electric service." Section 2802(17) specifies that the public purpose of the programs is to be "promoted by continuing universal service and energy conservation policies, protection and services and full recovery of such costs is to be permitted through a non-bypassable rate mechanism."

PP&L witness Dahl explained that PP&L plans to build upon its existing universal service and energy conservation programs. PP&L operates five programs that provide energy assistance to low-income customers.[89] These programs and their current level of

---

[88] *See* Section X.D of this Brief, which responds in detail to intervenors' arguments that PP&L's Generation Supply Group should not be permitted to use the "PP&L" name.

[89] Mr. Dahl describes each of these programs in his direct testimony. PP&L St. 16, pp. 8-13.

funding are as follows:

Customer Assistance and Referral Evaluation Service ("CARES")	$260,000
Operation HELP	$795,000
Winter Relief Assistance Program (WRAP)	$3,023,300
Keep Warm Plan	$1,000,000
On Track Payment Program Pilot	$2,000,000
Total	$7,078,300

The Company is proposing to move OnTrack from its pilot phase to a full-time program. The level of enrollment would be increased from 1,040 customers to about 10,000 customers by the year 2001. This "ramping up" of OnTrack anticipates an increase of 3,000 new participants annually. The expanded OnTrack program will target customers who have annual household income at or below 150 percent of poverty; are payment troubled[90]; and have an overdue electric bill.

There are approximately 58,000 customers who may be eligible for OnTrack based on the above characteristics. PP&L St. 16, p. 19. As a result, PP&L plans to concentrate the program on low-income customers who have a demonstrated inability to pay and may be subject to service termination. However, PP&L desires the flexibility to enroll customers who have mitigating circumstances as long as their annual household incomes do not exceed 175 percent of the federal poverty level.

90 A payment troubled customer is a customer who has missed a payment, who has contacted PP&L to negotiate a payment plan and with whom PP&L has negotiated a payment plan. Tr. 1942 (8/29/97).

A. Increased Funding

As the Commission has recognized, the challenge for the EDCs, the parties and the Commission is to set appropriate spending levels for universal service and energy conservation, in light of other spending priorities and the rate cap provisions of the Act, while maintaining funding for other aspects of safe and reliable local distribution services at least at current levels. Final Order Re: Guidelines for Universal Service and Energy Conservation Programs Made Pursuant to 66 Pa. C.S. § 2803, § 2807(17), 2804(8) and 2804(9) (entered July 11, 1997) at 3 ("Final Guidelines for Universal Service").

Although neither the Act nor the Commission's Final Guidelines for Universal Service specify a particular funding level or mandate an increase in total expenditures for universal service and energy conservation programs,[91] PP&L plans to increase its expenditures by over $7 million dollars above current funding levels. The annual level of funding for OnTrack will be expanded from $2 million to $9 million over a three-year period beginning January 1, 1999. Because PP&L will continue to solicit donations from its customers and employees, donations to Operation HELP are expected to increase annually. PP&L proposes to maintain the current level of annual funding for CARES, WRAP, and the Keep Warm Plan. PP&L St. 16, pp. 17-18.

In general, intervenor witnesses propose an unreasonable and unwarranted increase in funding levels for universal service and energy conservation programs, in some cases to over three times current levels, and expansion of the programs' eligibility criteria. *See, e.g.*, testimony of OCA witness Ms. Nancy Brockway; CEO witnesses Mr. Michael Karp, Mr. Craig Kuennen, and Mr. Geoffrey Crandall; and AARP witness Mr. Mark Cooper. These proposals are not supported by the Act or the evidentiary record in this case.

---

[91] *See* Final Guidelines for Universal Service at 14 ("[W]e must emphasize that nothing in these guidelines mandates an increase in total expenditures directed to meet universal service and energy conservation goals. To the contrary, these guidelines emphasize improving the cost effectiveness of existing efforts by shifting expenditures from less productive efforts to more effective programs.")

The Act has a focused purpose; that is, promoting effective competition in the area of generation. Section 2802(3) of the Act provides that " . . . it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market . . ." Providing cost-effective programs for low-income customers is an important component of the Act, but certainly it is not the *raison d'être* of the legislation. The primary intent of the universal service provisions of the Act is to ensure that current protections for low-income consumers are maintained in a competitive generation market: "The Commonwealth must, at a minimum, continue protections, policies and services that now assist customers who are low-income to afford electric service." 66 Pa. C.S. § 2802(10). The funding levels proposed by CEO, OCA and AARP simply were not envisioned by the Act. The intent of the Act is to restructure the electric utility industry to reflect competitive forces in the marketplace, not to implement a broad expansion of customer assistance programs.

As a basis for establishing the level of need for universal service and energy conservation programs, CEO's Mr. Kuennen presents information derived from the U. S. Census about poverty rates and the number of low-income households in PP&L's service area. However, Mr. Kuennan has erred in his conclusion about the need for utility-sponsored customer assistance programs.

The 1990 U. S. Census data for the Company's service area show that approximately 177,000 PP&L customers are at or below 150 percent of the federal poverty guidelines. This guideline is the proposed eligibility standards for programs such as OnTrack and WRAP. However, most of these customers (approximately 70 percent) pay their electric bills and are not in arrears with PP&L. PP&L St. 16-R, p. 7. It would be counterintuitive for the Company to encourage customers who have been paying the full amount of their electric bills to join OnTrack and begin paying only a portion of their bills.

The Commission urged regulated utilities to implement Customer Assistance Programs ("CAPs") such as OnTrack as an adjunct to collection activities for low-income customers. OnTrack has been an effective alternative for some low-income, payment-troubled customers who are confronted with termination of service. The program has improved customers' payment patterns and has helped PP&L to avoid the costs associated with collections and regulatory intervention. It was never intended, however, to be a broad social welfare program.

OCA witness Ms. Brockway recommends that PP&L's annual funding for OnTrack and weatherization (WRAP, Keep Warm Plan) should be $11.7 million and $4.7 million, respectively. OCA St. 6, pp. 23, 34. Ms. Brockway's proposal represents an increase in the funding levels suggested by PP&L of 30 percent (OnTrack) and 17.5 percent (WRAP and Keep Warm Plan). AARP witness Mr. Cooper has stated that deep discounts should be made available to all low-income households. AARP St. 1, pp. 25-26. The cost of extending OnTrack credits to all of PP&L's low-income customers would be prohibitive. The average OnTrack credit is $50 per month, or $600 annually. PP&L St. 16-R, p. 9. The cost of extending the credits, as Mr. Cooper suggests, would exceed $106 million annually (177,000 x $600). For the reasons described above, the increased funding levels recommended by these parties should be rejected.

B. Availability of Universal Service and Customer Assistance Programs

CEO witness Mr. Kuennen recommends that PP&L target 40 percent of low-income households (specifically, 71,000 customers) for participation in OnTrack.[92] CEO St. 1, p. 22.

---

92 Mr. Kuennen projects that 71,000 customers could be enrolled in OnTrack at an annual cost of about $23 million. This is a gross underestimation of the annual cost, which the Company estimates would be at least $53 million annually. The cost may even be higher because some of these customers would enter the program with overdue balances that would be forgiven if they made their monthly payments. The average revenue shortfall (i.e., the difference between the actual bill and the required OnTrack payment) for an OnTrack customer is $600. If 71,000 customers were enrolled in OnTrack, the annual revenue shortfall cost alone would be approximately $42.6 million (71,000 x $600).

OCA witness Ms. Brockway suggests that PP&L should serve 18,500 customers in OnTrack. OCA St. 6, p. 30. These proposals present three significant problems: 1) it would be impractical to effectively identify, interview, and enroll tens of thousands of customers; 2) the costs would be prohibitive; and 3) good-paying customers would be encouraged not to pay under the CEO's proposal.

Mr. Kuennan and Ms. Brockway also advocate increased funding levels for the baseload program under WRAP. As acknowledged by Ms. Brockway, each utility should tailor its energy conservation programs to address the conditions in its own service area. Tr. 2042 (8/29/97). Given that PP&L has the highest electric heat saturation rate of the eight major Pennsylvania electric utilities, PP&L Cr. Exam. Exh. 12, PP&L has properly chosen to focus its weatherization activities on electric heat customers.[93]

C. Allocation of Universal Service Program Costs

A number of intervenors recommend a kWh assessment of universal service program costs on all customer classes. As explained more fully in Section IX.D of this Brief, PP&L instead proposes to allocate its universal service charges on a per customer basis. PP&L's approach is consistent with the Commission's Final Guidelines for Universal Service, in which the Commission found that a kWh assessment would place a disproportionate responsibility for funding universal service and energy conservation programs on high volume users and is inconsistent with rate treatments for these programs in recent base rate cases. Final Guidelines at 20.

---

[93] This focus is also consistent with the Commission's low income usage reduction regulations, 69 Pa. Code § 58.10, which require utilities to place the highest priority on those eligible customers with the largest usage and greatest opportunities for bill reductions relative to the cost of providing program services.

D. Other Universal Service and Customer Assistance Program Recommendations

1. "Transfer" of Uncollectible Accounts

CEO witness Mr. Kuennan and OCA witness Ms. Brockway suggest that PP&L's current level of write-offs and credit and collection expenses associated with non-OnTrack low-income customers could be "transferred" to fund an expanded OnTrack Program rather than booking write-offs and credit and collection expenses associated with these amounts, in essence reducing its billings to these customers. CEO St. 1, p, 26; OCA St. 6, p. 26. Ms. Brockway acknowledges that this approach would not improve PP&L's bottom line, yet she asserts that even if no associated benefits of lowered collection costs or improved dollar payment amounts were realized by PP&L, the customer would benefit from this transfer from a delinquent debt posture to one of a reasonable opportunity to make complete payments.

As Mr. Dahl pointed out, Ms. Brockway's proposal should be rejected because it is based on the key false assumption that low-income customers do not pay any portion of their bills. To the contrary, however, PP&L's experience shows that low-income customers, even those that are payment-troubled, do often pay some amount toward their bills. For example, PP&L evaluated approximately 1,000 very low-income customers (at or below 110% of the federal poverty guidelines) and determined that even those customers pay PP&L six or seven times per year. Tr. 1948 (8/29/97).

2. Customer Choice for OnTrack Customers

PP&L supports the OCA's recommendation to allow OnTrack customers to choose Alternative Suppliers; however, this participation must be subject to three important conditions. First, OnTrack participants who select an Alternative Supplier would be required to receive a single bill from PP&L. Second, as a condition of serving OnTrack customers, Alternative Suppliers would agree to discount the energy portion of the supply bill by a percentage equal to the overall percentage reduction established pursuant to the OnTrack program. Third, the

Alternative Suppliers would agree to absorb the supply portion of the revenue shortfall that is written off monthly for OnTrack customers.

A key objective of OnTrack is to encourage and develop good payment habits among customers. This objective could be best accomplished by offering one bill to OnTrack customers who choose an Alternative Supplier. PP&L believes so strongly in this concept that it greatly simplified the OnTrack bill to encourage regular payments. A combined bill would streamline administrative procedures for the OnTrack agencies and reduce confusion for customers who may have questions. Requiring these customers to write two checks monthly -- one to PP&L and one to the Alternative Supplier -- would add unnecessary complexity to the program.

PP&L's average monthly electric bill for low-income, payment-troubled customers is about $88, and the average monthly electric bill for OnTrack customers is $47. In other words, the Company provides a monthly bill reduction of $41, or 53 percent. This revenue shortfall is written off monthly. PP&L St. 16-R, p. 22. PP&L recommends that Alternative Suppliers provide a pro rata reduction in energy supply charges to those OnTrack customers who choose an Alternative Supplier. Without such a pro rata reduction, the amount of the monthly bill reduction could reduce the transmission and distribution portion of the customer's bill to less than zero.

PP&L also believes that Alternative Suppliers should share in the costs of the revenue shortfall associated with OnTrack customers. Generation accounts for approximately 25 percent of the bill, and using the above example of the $41 revenue shortfall for the average OnTrack customer, an Alternative Supplier would be responsible for $10.25 of the write-off. The remaining $30.75 would be assigned to PP&L. Because the revenue shortfall includes some generation charges, it is fair for Alternative Suppliers to assume responsibility for the portion of their the revenue shortfall. PP&L's proposal would treat both PP&L and the Alternative Supplier on the same basis while satisfying the Act's objective of providing choice to all customers in Pennsylvania.

XIII. ENVIRONMENTAL ISSUES

A. Disclosure of Fuel Mix and Waste Discharge Information

Environmentalists witness Bruce E. Biewald proposes that the Commission require all retail electricity suppliers selling in Pennsylvania to disclose their fuel mix and key air and other waste emissions to consumers in the form of a label and that the tracking of transactions to support disclosure and labeling should be done by the PJM Independent System Operator ("ISO"). Environmentalists' St. 2, p. 5. OCA witness Barbara Alexander also advocates fuel mix disclosure. OCA St. 5, pp. 29-30.

Mr. Biewald's proposal goes beyond the Commission's recently-proposed rules on Customer Information Disclosure for Electricity Providers Docket No. L-00970126, which propose that suppliers provide a written disclosure statement of energy sources, and, if the supplier cannot identify the energy source of its supply (if, for example, the supply is purchased from a power pool), disclosure of the average energy mix from the relevant market, including an identification of that market by name. The source of supply mix must be provided to customers upon request, upon entering into a sales agreement and whenever a significant change occurs in the terms of service. The proposed rules do not require the disclosure of environmental attributes other than fuel mix. The Commission's rulemaking is a more workable system than the one proposed by Mr. Biewald that satisfies the needs of responsible disclosure. *See* PP&L St.10-R, p. 20 Moreover, this Commission lacks the power to require the PJM ISO to adopt Mr. Biewald's proposal.

The Environmentalists witness Mr. Schoengold asserts that PP&L has not proposed to improve significantly the environmental performance of its existing generating plants. Environmentalists' St. 1, p. 36. As a result, Mr. Schoengold argues, PP&L's generating plants will be able to compete unfairly in a competitive market where builders of new power plants will be required to meet stringent emissions standards.

To address these concerns, Mr. Schoengold recommends that the Commission require that all power purchased in Pennsylvania come from plants meeting the latest environmental standards, Environmentalists' St. 1, p. 37. Mr. Schoengold notes that other states have enacted similar regulations based on their right to protect the health and welfare of their citizens. This proposal should be rejected for several reasons.

First, although the Commission retains broad authority to regulate utility service, facility and rate issues, it is the Pennsylvania Department of Environmental Protection and the U.S. Environmental Protection Agency that have the broad authority to implement and administer programs for the protection of the environment, including rules relating to air emissions.[94] It is well established that the Commission does not possess jurisdiction over environmental issues simply because a public utility may be involved. *See, e.g., Country Place Waste Treatment Co., Inc. v. Pa. P.U.C.*, 654 A.2d 72, 75-76 (Pa. Commonwealth Ct. 1995) (the Pennsylvania Utility Code fails to directly or indirectly grant the Commission the authority to regulate air pollution produced by public utilities); *Rovin v. Pa. P.U.C.*, 502 A.2d 785 (Pa. Commonwealth Ct. 1986) (Department of Environmental Protection, not the Commission, has jurisdiction over complaint alleging water quality issues).

As PP&L witness Dr. Tierney pointed out at the hearing, although § 2802(21) of the Act authorizes the Commission to work with state environmental regulators and to support certain changes to federal law and regulation on the issue of air emissions, the Act does not extend rate

---

[94] For example, EPA has proposed a rule requiring certain Northeast and Midwest states to revise their air pollution control plans to mitigate the transport of ozone across state lines. *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone*, 62 Fed. Reg. 60318 (Nov. 7, 1997). EPA hopes to issue a final rule in September 1998. The DEP administers the EPA's air quality regulations through the Pennsylvania State Implementation Plan and has concurrent authority to impose penalties for noncompliance.

regulation authority for emission policy above and beyond compliance with current law and regulation from environmental regulators. Tr. 830 (8/19/97).

Second, 48% of the capital expenditures necessary to operate PP&L's facilities for the period 1997 through 2001 will be incurred to ensure environmental compliance. Projected capital costs after 2001 include individual environmental compliance projects that likely will be required at each facility. PP&L St. 10-R, pp. 37-38. As Mr. Krall explained:

> A significant portion of these costs are to comply with provisions of the CAAA [Clean Air Act Amendments]. These costs include Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems for NOx reductions beyond those already achieved with the installation of Reasonably Available Control Technology in order to comply with the likely requirements of Title I of the CCAAA [sic]. Other costs include scrubbers to remove air toxics and fine particulates to comply with Title III of CAAA. For the years 2003, 2004, and 2005, 54% of the $429 million of capital identified, or $230 million, will be for compliance with the CAAA, alone. PP&L St. 10-R, p. 38

Third, Mr. Schoengold offers no evidence to support his claim that existing plants enjoy a competitive advantage under the current environmental regulatory scheme. In fact, with the adoption of the Clean Air Act, environmental regulations have imposed increasing compliance burdens on existing plants. These compliance obligations have increased significantly with the passage of the Clean Air Act Amendments. Contrary to Mr. Schoengold's assertions, Mr. Krall explained that the current regulatory scheme is leading to the retirement of older plants in keeping with one of the basic "assumptions" identified by Mr. Schoengold as underlying the Clean Air Act:

> During its most recent base rate proceeding, PP&L requested that the Commission approve shorter lives for certain of its older, less efficient generating plants in large part because the Company believed (and continues to believe) that there is significant uncertainty as to whether it will be cost-effective to retrofit these plants to meet the new [environmental] requirements. It is because of the likelihood that compliance standards for existing plants will continue to be raised and the likelihood . . . that replacement plants

> will operate with greater efficiency that PP&L believes that its proposed deactivation dates are the appropriate measure to use in this filing. PP&L St. 10-R, pp. 39-40.

B. Renewables Pilot Program

OCA witness Ms. Brockway's suggests that PP&L provide funding of $700,000 for photovoltaic and active solar water heating pilots. Neither the Act nor the Commission's Final Guidelines for Universal Service mandate such pilot programs.[95] Because the annual cost savings would be very low, in light of PP&L's relatively low electric rates, the payback periods would be significant.[96] Most consumers would not be induced to buy a system that required well over a decade to provide benefits.

Developing, implementing, and evaluating these pilots would be time consuming and expensive for the level of benefits received. As described in PP&L witness Mr. Dahl's testimony, because of the long payback period, the complexity of the systems, the difficulty of installation and maintenance, the likely resistance from landlords, and the Commission's direction in its final order, the OCA's recommendation to fund renewable energy pilots should be rejected.

---

95 The Commission's Final Guidelines for Universal Service expressly provide that: "Although we believe that research and development are important, we will not direct that universal service and energy conservation funds be spend for research and development. Unlike the California legislature that specifically provided funds for research and development, the Commonwealth's Act gives no direction for such expenditures." Final Guidelines for Universal Service at 6.

96 Indeed, Ms. Brockway notes a 14-year payback period for photovoltaic. OCA St. 6, p. 38.

XIV. CONCLUSION

For all of the reasons set forth above, PP&L, Inc. respectfully requests that the Pennsylvania Public Utility Commission approve its Restructuring Plan in its entirety.

Respectfully submitted,

Paul E. Russell
PP&L, Inc.
Two North Ninth Street
Allentown, PA 18101

Donald A. Kaplan
Lisa M. Helpert
Preston Gates Ellis
& Rouvelas Meeds LLP
1735 New York Avenue, N.W.
Suite 500
Washington, D.C. 20008-4759
Attorneys for PP&L, Inc.

Dated: February 12, 1998

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION FOR APPROVAL OF
A RESTRUCTURING PLAN

Docket No R-00973954

TABLES

Dated: February 12, 1998

TABLE A

The following are active parties in Docket No R-00973954:

Office of Consumer Advocate
Office of Small Business Advocate
Office of Trial Staff
Allegheny Power
American Association of Retired Persons
Commission on Economic Opportunity
Delmarva Power & Light
Enron Power Marketing Inc.
Environmentalists
Local 1600, International Brotherhood of Electric Workers
Eric Epstein
Gilberton Power
Mid-Atlantic Power Supply Association
New Energy Ventures
Pennsylvania Petroleum Association
PP&L Industrial Customer Alliance
Schuylkill Energy Resources
United States Department of Defense.

The following are inactive parties in Docket No R-00973954:

Allegheny Electric Cooperative
American Energy Solutions
Anthracite Regional Power Producers
Bethlehem Steel
Center for Energy and Economic Development
Duke Energy Trading Marketing
Dupont Power Marketing
Electric Clearinghouse Inc.
ERI Services Inc.
GPU Energy
Kraft Foods
Noram Energy Management
PECO Energy Company
Pennsylvania Association of Plumbing Heating & Cooling Contractors
Pennsylvania Electric Consumers Council
PP&L Rate Payers Association
Pennsylvania Retailers Association
Vastar Power Marketing

TABLE B

SUMMARY OF
STRANDED COSTS (PUC JURISDICTIONAL)
REVENUE REQUIREMENTS METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Nuclear	$2,824,620		
Fossil	670,016		
NUG	650,960		
Regulatory Assets	354,326		
Total PUC Jurisdictional Stranded Costs - NPV in 1999 Dollars	$4,499,922		

STRANDED COST
CALCULATION - NUCLEAR (PUC JURISDICTIONAL)
REVENUE REQUIREMENTS METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Revenue Required - NPV (1999)	$7,704,351		
Less: Market Revenue - NPV (1999)	4,879,731		
Total PUC Jurisdictional Nuclear Stranded Cost - NPV in 1999 Dollars	$2,824,620		

STRANDED COST
CALCULATION - FOSSIL (PUC JURISDICTIONAL)
REVENUE REQUIREMENTS METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Revenue Required - NPV (1999)	$9,194,236		
Less: Market Revenue - NPV (1999)	(8,524,221)		
Total PUC Juris-dictional Fossil Stranded Cost - NPV in 1999 Dollars	$670,015		

STRANDED COST CALCULATION - NON-UTILITY GENERATION (PUC JURISDICTIONAL) REVENUE REQUIREMENTS METHOD ($000)

	Company Claim	Adjustments	Adjusted Amount
Cost of Purchase - NPV (1999)	$1,141,469		
Less: Market Value - NPV (1999)	(543,374)		
Cost in Excess of Market Value - NPV (1999)	598,095		
Plus: Buy-out Payments - NPV (1999)	52,865		
Total PUC - Jurisdictional NUG Stranded Cost - NPV in 1999 Dollars	$650,960		

STRANDED COST CALCULATION -
REGULATORY ASSETS (PUC - JURISDICTIONAL)
REVENUE REQUIREMENTS METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Unrecovered Energy Costs	$76,815		
Post-Retirement Benefits	8,730		
Susquehanna Operating Costs	9,830		
Common Plant	7,783		
Retired Miners' Healthcare Costs	6,308		
DOE Assessment	16,361		
Deferred Refueling Costs	7,996		
Voluntary Early Retirement Costs	14,085		
Employee Transition Costs	17,106		
Rate Case Expenses	176		
Taxes Recoverable	231,709		
Regulatory Liabilities	(42,573)		
Total PUC Jurisdictional Regulatory Assets Stranded Cost - NPV in 1999 Dollars	$354,326		

TABLE C

SUMMARY OF STRANDED COSTS
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Nuclear	$ 2,528,761		
Fossil	735,571		
Total Generation	3,264,332		
NUGs	650,960		
Regulatory Assets	584,630		
Total NPV as of 1/1/99	**$ 4,499,922**		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - GENERATION
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Net Book Value	$ 3,820,858		
(Market Value)	(676,969)		
NPV as of 1/1/99	3,143,889		
PV of Nuclear Decommissioning	120,443		
Total NPV as of 1/1/99	**$ 3,264,332**		
Discount Rate	7.92%		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - NUCLEAR
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Net Book Value	$ 2,554,563		
(Market Value)	(146,245)		
NPV as of 1/1/99	2,408,318		
PV of Nuclear Decommissioning	120,443		
Total NPV as of 1/1/99	**$ 2,528,761**		
Discount Rate	7.92%		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - FOSSIL
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Net Book Value	$ 1,266,295		
(Market Value)	(530,724)		
Total NPV as of 1/1/99	**$ 735,571**		
Discount Rate	7.92%		
PUC Jurisdictional Percent	95.80%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - REGULATORY ASSETS
ASSET VALUE METHOD
($000)

	Company Claim Gross	Company Claim Net	Adjustment	Adjusted Amount
Unrecovered Energy Costs	$ 80,150	$ 76,815		
Post-Retirement Benefits	14,495	8,730		
Susquehanna Operating Costs	12,836	9,830		
Common Plant Adjustment	18,220	7,783		
Retired Miners' Healthcare Costs	6,582	6,308		
DOE Assessment	22,923	16,361		
Deferred Refueling Costs	8,343	7,996		
Voluntary Early Retirement Costs	15,190	14,085		
Employee Transition Costs	22,279	17,106		
Rate Case Expenses	184	177		
Taxes Recoverable	649,023	496,995		
Regulatory Liabilities	(101,278)	(77,556)		
Total NPV at 1/1/99		**584,630**		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

STRANDED COSTS CALCULATION - NUGS
ASSET VALUE METHOD
($000)

	Company Claim	Adjustments	Adjusted Amount
Cost of Purchases	$ 1,141,469		
Market Value	543,374		
Cost in Excess of Market Value	598,095		
Plus: Buy-out Payments	52,865		
Total NPV as of 1/1/99	**$ 650,960**		
PUC Jurisdictional Percent	97.20%		

NOTE: The above values are PUC jurisdictional amounts. The percentage is calculated by taking the average of the annual jurisdictional percentage from 1999 through 2024.

TABLE D

COMPARSON OF OCA AND PP&L CALCULATIONS OF STRANDED COSTS UNDER THE ASSET VALUE METHOD

DESCRIPTION	ASSET VALUE METHOD OCA ASSUMPTIONS	ASSET VALUE METHOD PP&L ASSUMPTIONS	DIFFERENCE OCA AND PP&L ASSUMPTIONS	See Note
NET GENERATION PLANT	$ 3,248,442	$ 3,820,858	$ 572,416	(1)
LESS:MARKET VALUE	3,110,321	676,969	(2,433,352)	(2)
STRANDED GENERATION PLANT	138,121	3,143,889	3,005,768	
REGULATORY ASSETS	259,249	584,630	325,381	(3)
NUG CONTRACTS	574,708	650,960	76,252	(4)
NUCLEAR DECOMMISSIONING	108,125	120,443	12,318	(5)
TOTAL STRANDED COSTS	**$ 1,080,203**	**$ 4,499,922**	**$ 3,419,719**	

Note 1... Net Generation Plant

Jurisdictional Allocation	$ 659,725
CWIP	108,928
Depreciation swap	(196,237)
	$ 572,416

Note 2...Market Value

Plant Retirement	$ 144,881
Coal Price	230,157
Nuclear Capacity Factor	46,679
New CT Fuel	159,298
PJM Imports	226,296
Capacity Prices	38,446
Inflation Adjustment	198,583
A&G Expense	402,735
Fossil Decommissioning	315,867
Productivity Factor	66,162
Keystone/Conemaugh Lives	71,281
Taxes Other Than Income	133,795
Discount Rate	135,346
Jurisdictional Allocation	(336,609)
Land Escalation	78,045
Capital Additions	165,318
Deferred Income Tax Adjustment	281,671
Discount Method	71,072
Miscellaneous Adjustments	4,330
	$ 2,433,352

Note 3...Regulatory Assets

Taxes Recoverable	$ 230,304
Unrecovered Energy Costs	60,570
DOE Assessment	16,361
SSES Deferred Refueling Costs	7,996
Employee Transition Costs	14,540
Adj Req. OCA Original to Surrebuttal	(29,585)
Jurisdictional Allocation	40,367
Rate Case Expenses	177
Discount Rate	(9,534)
Discount Method	(5,815)
	$ 325,381

Note 4... NUG Contracts

Capacity Adjustment	$ 56,911
OCA Pricing	35,487
Jurisdictional Allocation	4,068
Discount Rate	(11,232)
Discount Method	(8,982)
	$ 76,252

Note 5...Nuclear Decommissioning

Jurisdictional Allocation	$ 20,864
Discount Rate	(647)
Discount Method	(7,899)
	$ 12,318

NOTES TO TABLE D

Table D provides a reconciliation of the PP&L and OCA calculation of stranded costs using the OCA's asset value method. The table starts with "Net Generation Plant" and subtracts "Market Value" to obtain "Stranded Generation Plant." The table then adds "Regulatory Assets," "NUG Contracts," and "Nuclear Decommissioning" to arrive at "Total Stranded Costs." Column 1 sets forth the OCA claim; Column 2 sets forth the PP&L claim; and Column 3 sets forth the difference between the two claims.

The Table also contains five "Notes" which provide a detailed reconciliation of the differences between the PP&L and OCA cases on Net Generation Plant, Market Value, Regulatory Assets, NUG Contracts and Nuclear Decommissioning. The following discussion summarizes each adjustment and provides a cross-reference to where the issue is addressed in PP&L's Brief.

Note 1 — Net Generation Plant

Jurisdictional Allocation. PP&L adjusts its jurisdictional allocation to reflect expiring wholesale contracts. OCA freezes the jurisdictional allocation at January 1, 1996 and ignores subsequent changes. This issue is addressed in Section V.A.

CWIP. PP&L adjusts the plant in service balance to reflect estimated plant in service at January 1, 1999. OCA does not make this adjustment. This issue is addressed in Section V.D.5.

Depreciation Swap. PP&L proposes to transfer excess T&D depreciation reserve to generation, thereby reducing stranded costs as contemplated by the Act. The OCA opposes this adjustment and thereby shows a higher net generation plant value. This issue is discussed in Section II.D.2.b.

Note 2 - Market Value

Plant Retirement. PP&L's market revenue calculation reflects the retirement of its generating plants at the end of their book lives. OCA indefinitely extends the lives of PP&L's coal plants. This issue is addressed in Section IV.C.2.e.vii.

Coal Price. OCA projects increasing gas prices and an ever widening gap between gas and coal prices. PP&L asserts that OCA's gas prices are too high and that there is no support for the divergence between gas and coal prices. This adjustment shows the effect of using OCA's gas prices and escalating coal prices at the same rate as gas prices after 2000. This issue is addressed in Section IV.C.2.a.ii.

Nuclear Capacity Factor. PP&L uses a nuclear capacity factor of 78% in its market price projection. OCA uses 75%. This issue is addressed in Section IV.C.2.e.i.

New CT Fuel. The OCA market price forecast assumes new combustion turbines will burn 50% gas and 50% oil. PP&L projects that the new CTs will burn the least expensive fuel. This issue is discussed in Section IV.C.1.a.

PJM Imports. OCA assumes a significant decline in PJM imports after 2005. PP&L does not. This issue is addressed in Section IV.C.1.a.

Capacity Prices. PP&L and OCA disagree on future market prices for capacity. This issue is addressed in Section IV.B.2.

Inflation Adjustment. PP&L employs a 2.5% inflation assumption in its market price forecast. OCA uses a higher rate. This issue is addressed in Section IV.C.2.b.

A&G Expense. PP&L allocates A&G expenses using the cost allocation factors from the cost allocation study approved by the PUC in its 1995 base rate case. OCA, without discussion, reduces generation-related A&G by $402.7 million. This issue is addressed in Section V.D.1.

Fossil Decommissioning. In accordance with the Act, PP&L claims its fossil decommissioning expense as a stranded cost. OCA opposes this claim. This issue is addressed in Section V.C.4.

Productivity Factor. OCA proposes to reduce future O&M expenses to reflect improved productivity. PP&L asserts it has already reflected such improvements. This issue is addressed in Section V.D.2.

Keystone/Conemaugh Lives. PP&L uses its book lives for the Keystone and Conemaugh plants. OCA proposes a life extension. This issue is addressed in Section V.C.10.

Taxes Other Than Income. PP&L projects that taxes other than income will increase at the rate of inflation. OCA proposes flat taxes. This issue is addressed in Section V.C.3.

Discount Rate. PP&L uses a discount rate equal to its weighted average after-tax cost of capital, including an 11.5% return on common equity, as approved by the PUC in PP&L's 1995 base rate case. OCA proposes a 10% ROE. This lower rate increases the net present value of market revenue and correspondingly decreases stranded costs. This issue is addressed in Section V.B.1 and Section VI.

Jurisdictional Allocation. This is the same issue discussed in Note 1. The combination of the OCA's higher market price and lower jurisdictional allocation decreases market revenue by $336.6 million. This increase partially offsets increases in stranded generation plant ($659.725 million), stranded regulatory assets ($40.367 million), stranded NUG contracts ($4.068 million) and stranded nuclear decommissioning ($20.864 million) caused by the OCA's constant jurisdictional allocation. This issue is addressed in Section V.A.

Land Escalation. OCA includes an estimate of land value as an offset to stranded costs. PP&L asserts that the OCA claim is overstated. This issue is addressed in Section V.D.3.

Capital Additions. OCA treats capital additions as operating expenses, thereby understating tax expense and overstating market value. This issue is addressed in Section V.D.4.

Deferred Income Tax Adjustment. OCA fails to properly reflect deferred taxes and thereby understates asset value. This issue is addressed in Section V.D.7.

Discount Method. PP&L discounts to present value on a monthly basis. OCA discounts on a semi-annual basis. Applied to market value, the monthly method decreases net present market value and increases stranded costs.

Miscellaneous Adjustments. This is a fallout figure for other unexplained differences in PP&L and OCA models.

Note 3 — Regulatory Assets

Taxes Recoverable. PP&L calculates taxes recoverable over the seven-year CTC period consistent with the PECO decision. OCA does not. This issue is addressed in Section V.D.6.

Unrecovered Energy Costs. PP&L's stranded cost claim includes unrecovered energy costs deferred pursuant to PUC Order. OCA opposes this claim. This issue is addressed in Section V.C.1.

DOE Assessment. OCA identifies a double count in PP&L's claim. PP&L does not contest this adjustment, which is discussed in Section V.C.7.

SSES Deferred Refueling Costs. PP&L has recorded as a regulatory asset the cost of the first Susquehanna refueling outage which was not reflected in rates. OCA opposes the claim. This issue is addressed in Section V.C.7.

Employee Transition Costs. PP&L claims certain employee transition costs as a stranded cost in accordance with the Act. OCA opposes this claim. This adjustment is addressed in Section V.C.2.

Adjustment to OCA Surrebuttal. In its rebuttal case, PP&L makes a $27.8 million downward adjustment to its claim to adjust taxes reconcile for the T&D depreciation reserve swamp. OCA does not incorporate this concession in its surrebuttal.

Jurisdictional Allocation. This is the same issue discussed in Note 1. PP&L's higher jurisdictional allocation increases jurisdictional regulatory assets. This adjustment is addressed in Section V.A.

Rate Case Expense. PP&L has recorded a regulatory asset for unrecovered rate case expense. OCA opposes this adjustment. This adjustment is addressed in Section V.C.11.

Discount Rate. This is the same issue discussed in Note 2. Here, the OCA's lower discount rate increases the present value of the regulatory asset and increases stranded costs. This issue is addressed in Section V.B.1 and VI.

Discount Method. This is the same issue discussed in Note 2. Here, the OCA's semi-annual method increases the present value of the regulatory asset and increases stranded costs. This issue is addressed in Section VI.B.2.

<u>Note 4 — NUG Contracts</u>

Capacity Adjustment. PP&L uses a NUG capacity factor of 90% to project NUG output. OCA uses a lower figure. This issue is addressed in Section IV.C.2.e.v.

OCA Pricing. The OCA uses a higher market price than PP&L. This decreases NUG stranded costs. This issue is addressed in Section IV.

Jurisdictional Allocation. This is the same issue addressed in Notes 1,2,3. The OCA's use of a lower jurisdictional allocation decreases the jurisdictional share of NUG contracts and decreases jurisdictional stranded costs. This issue is addressed in Section V.A.

Discount Rate. This is the same issue discussed in Notes 2 and 3. The OCA's use of a lower discount rate increases the net present value of NUG contract payments and increases stranded cost. This issue is addressed in Section V.B.2 and VI.

Discount Method. This is the same issue discussed in Notes 2 and 3. Here, the OCA's semi-annual method increases the present value of NUG payments and increases stranded costs. This issue is discussed in Section VI.B.2.

<u>Note 5 — Nuclear Decommissioning</u>

Jurisdictional Allocation. This the same issue discussed in Notes 1, 2, 3, and 4. The OCA's use of a lower jurisdictional allocation decreases the jurisdictional share of nuclear decommissioning costs and decreases jurisdictional stranded costs. This issue is addressed in Section V.B.5.

Discount Rate. This is the same issue addressed in Notes 2, 3 and 4. The OCA's use of a lower discount rate increases the net present value of nuclear decommissioning stranded costs. This issue is addressed in Sections V.B.1 and VI.

Discount Method. This is the same issue addressed in Notes 2, 3 and 4. The OCA's use of a semi-annual method increases the net present value of nuclear decommissioning stranded costs.

TABLE E

($ Billions)

NPV of PP&L Recoverable Stranded Costs as of 1/1/99 (Tr. 964 (8/20/97))	$ 4.026
Less Gross Receipts Tax @ 4.4%	(0.177)
Taxable Recoverable Stranded Costs	3.849
Less Taxes on Stranded Cost Recovery @ 41.5% Effective Tax Rate (PP&L Exh. JRS 1)	(1.597)
After-Tax Recoverable Stranded Costs	**2.252**

TABLE F

PP&L Pre-Tax Cost of Capital

	Ratio	Cost	Weighted Cost	Tax Adjustment	Pre-tax Cost
Debt	47.0%	7.89%	3.71%	0.00%	3.71%
Preferred	7.8%	7.10%	0.55%	0.39%	0.95%
Equity	45.2%	11.50%	5.20%	3.69%	8.88%
Total Cost			9.46%	4.08%	**13.54%**

Allowed Return to Total Capital of 7.89%

	Ratio	Cost	Weighted Cost	Tax Adjustment	Pre-tax Cost
Debt	47.0%	7.89%	3.71%	0.00%	3.71%
Preferred	7.8%	7.89%	0.62%	0.44%	1.05%
Equity	45.2%	7.89%	3.57%	2.53%	6.10%
Total Cost			7.89%	2.97%	**10.86%**
EffectiveTax Rate	41.4935%				

Note: Based on PP&L Exh. JRS1, Tab A, Attachment 1.