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August 14, 1995

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John G. Alford, Secretary
Pennsylvania Public Utility Commission
New Filing Section
Room B-20, North Office Building
Commonwealth & North Streets
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Pennsylvania Power & Light Company
Docket No. R-00943271

Dear Secretary Alford:

Enclosed for filing in the above-captioned proceeding are an original and nine copies of the Exceptions of Pennsylvania Power & Light Company. Also enclosed is an additional copy of the Company's Exceptions which we request that you date stamp and return to us as evidence of filing.

As indicated on the attached Certificate of Service, copies of the Exceptions have been served on Administrative Law Judge Robert A. Christianson and all active parties of record.

Sincerely,

Thomas P. Gadsden

Thomas P. Gadsden
Counsel for Pennsylvania
Power & Light Company

DOCUMENT FOLDER

TPG\jta
Enclosures
cc: Honorable Robert A. Christianson
Certificate of Service

ORIGINAL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
v.	:	Docket No. R-00943271 (1994)
PENNSYLVANIA POWER & LIGHT COMPANY	:	

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EXCEPTIONS OF RESPONDENT

PENNSYLVANIA POWER & LIGHT COMPANY

To The Recommended Decision Of
Administrative Law Judge Robert A. Christianson

DOCKETED
AUG 14 1995

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DATE: August 14, 1995

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I. INTRODUCTION

Pennsylvania Power & Light Company ("PP&L" or the "Company") initiated this rate proceeding on December 30, 1994 by filing with the Pennsylvania Public Utility Commission (the "Commission") Supplement No. 50 to Tariff Electric-Pa. P.U.C. No. 200. Supplement No. 50 requests an increase in the Company's total revenues from retail electric sales of $261.6 million, or approximately 11.7%. On July 31, 1995, Administrative Law Judge Robert A. Christianson (the "ALJ") issued his Recommended Decision proposing that the Commission approve additional annual revenues totalling $61.7 million -- less than one-quarter of the amount sought by PP&L and an increase of only 2.76%. The Company herewith files its Exceptions to those findings and conclusions of the Recommended Decision with which it disagrees.

Before turning to the specific issues that must be addressed, it is appropriate to place this proceeding in context. As the Commission is aware, PP&L last filed for a general base rate increase in 1984. Since that time, the Company has invested hundreds of millions of dollars in new and upgraded utility plant and has incurred substantial increases in operating expenses. PP&L has been able to offset these increases, to some extent, by aggressively refinancing high-cost debt and preferred stock, by actively promoting economic development in its service territory and by cutting costs where it could without compromising service reliability.

Because of these measures, PP&L's rates have essentially remained unchanged over the last ten years even though the cost of other goods and services, as measured by accepted inflation indices, has increased by more than 30%. Unfortunately, however, the steps undertaken by the Company to foster rate stability are no longer enough. Rather, and as explained in its Initial and Reply Briefs to the ALJ, PP&L needs significant rate relief if it is to recover its costs and maintain its A-bond rating; to ensure that today's customers pay today's cost of service; to continue its leadership role in economic development and social programs; and, most importantly, to provide safe, reliable and high quality service to its customers.

Although the Recommended Decision carefully analyzes the myriad of individual claims and adjustments presented in this case, it stops well short of providing the level of relief which PP&L requires. The causes of that shortfall will be explored in depth in these Exceptions. However, two recommendations stand out: (1) that the Company be denied a return on 564 Mw of alleged "excess" generating capacity and (2) that it be awarded an equity allowance of only 10.9%. These proposals, and the findings on which they are based, are contrary to the overwhelming weight of the evidence, cannot be justified when measured against any reasonable standard, and, if adopted, would seriously impair PP&L's efforts to move forward with its customers in constructive partnership. Those two recommendations, and others discussed in these Exceptions, must be rejected and the level of allowed rate relief must be substantially increased.

II. EXCEPTIONS

PP&L respectfully notes the following Exceptions to the Recommended Decision:

1. Alleged "Excess" Generating Capacity. Exception is taken to the recommendation that the Company be denied a return on its investment in 564 megawatts ("Mws") of used and useful generating capacity (R.D., pp. 29-30). This adjustment (a) is entirely inconsistent with the ALJ's rejection of PP&L's proposal regarding the prospective treatment of costs associated with terminating off-system bulk power sales agreements, (b) seriously understates PP&L's reliability requirements by adopting an unprecedented 16% maximum reserve margin and (c) would penalize the Company for complying with its obligation to purchase the output from Qualifying Facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

2. Cost Of Common Equity. Exception is taken to the recommendation that PP&L should be allowed the opportunity to earn a rate of return on common equity of only 10.9% (R.D., p. 179). This allowance is well below recent Commission findings for utilities with far less risk than the Company and is not supported by the evidence of record.

3. Depreciation Of Older Fossil-Fired Generating Units. Exception is taken to the rejection of PP&L's proposed depreciable lives for its older fossil-fired generating units (R.D., pp. 125-126). The Company's depreciation expense claim properly reflects the significant uncertainties regarding the prospective operational and economic viability of the units in question and is in full accord with the Commission's prior refusal to recognize the possibility of life-extension until the necessary investment to extend lives has been made.

4. Nuclear Decommissioning Costs: Contingency. Exception is taken to the recommendation that PP&L's claim for nuclear decommissioning costs be reduced by $2.5 million to eliminate a contingency factor (R.D., p. 100). The Company's decommissioning cost estimate is reasonable, fully supported by the evidence and the inclusion of contingency is consistent with prior regulatory decisions from this and other jurisdictions.

5. Nuclear Decommissioning Costs: Post-Shutdown Earnings. Exception is taken to the recommendation that PP&L's claim for nuclear decommissioning costs be reduced by $2.4 million to reflect earnings that purportedly would accrue on decommissioning trust fund assets subsequent to the actual shutdown of Susquehanna Units 1 and 2 ("SSES 1 and 2") (R.D., p. 100). This proposal is contrary to the rules of the Nuclear Regulatory Commission which require that a nuclear decommissioning trust be fully funded in the amount necessary to terminate the license at the time of plant shutdown.

6. Fossil Decommissioning Costs. Exception is taken to the rejection of PP&L's request that it be allowed to begin to recover the cost of decommissioning its fossil-fired generating plants (R.D., p. 107). The pre-funding of this substantial expense will assure that public health and safety risks are addressed upon the retirement of the facilities in question and, as the ALJ found, avoid the serious "inter-generational" inequity of imposing these costs on future customers.

7. SSES 1 "Early Window" Costs. Exception is taken to the rejection of PP&L's claim for recovery of SSES 1 "early window" costs (R.D., p. 62). That PP&L did

not seek recovery of these costs in its SSES 2 base rate proceeding does not make its current request untimely or unreasonable.

8. Additions To Taxable Income. Exception is taken to the reduction of the Company's claims for Federal and Pennsylvania income taxes to reflect the elimination from taxable income of three specific items (R.D., p. 137). There is no basis for "cherry picking" individual expenses for inclusion or exclusion when PP&L's overall income tax expense claim was shown to be a normal and reasonable amount for ratemaking purposes. Moreover, and at a minimum, the ALJ's proposed tax expense adjustments must be reduced by $610,000 (Federal) and $215,000 (Pennsylvania) to be consistent with his recommended adoption of an OTS adjustment to claimed uncollectible accounts expense.

9. Gross Receipts Tax. Exception is taken to the reduction of PP&L's claim for gross receipts tax by $745,000 (R.D., pp. 130-132). The proposed adjustment is based on a theory which was not advanced by any party and disregards the fact that the Company made no claim for the additional uncollectible accounts expense associated with its requested revenue increase.

10. Treatment Of Costs Associated With Terminating Off-System Sales Agreements. Exception is taken to the rejection of PP&L's request to reflect in its Energy Cost Rate ("ECR") the costs, net of revenue credits, associated with capacity that will become available to the Company incrementally upon the termination of its long-term sales agreements with Jersey Central Power & Light Company ("JCP&L"), Atlantic Electric ("AE") and Baltimore Gas & Electric Company ("BG&E"). This innovative proposal would

assure that customers receive immediately the benefits of any off-system capacity-related sales and, at the same time, would mitigate the need for future base rate filings.

11. Rate Case Expense. Exception is taken to the recommendation that PP&L's rate case expense claim be reduced by $373,000 to reflect a four-year normalization period. Given the level of rate relief proposed by the Recommended Decision, it is inconceivable that the Company could wait that long before seeking a further increase in base rates.

12. Environmental Remediation Costs. Exception is taken to the recommendation that PP&L's claim for environmental remediation costs be reduced by $326,000 to reflect the maximum amount the Company is required to expend pursuant to a recently-executed agreement with the Pennsylvania Department of Environmental Resources. The amount claimed by the Company is more reflective of the amount PP&L is likely to spend on an ongoing basis and should be approved.

13. Cost Of Service Study: Allocation Of QF Output Payments. Exception is taken to the adoption of both PPLICA's and PP&L's proposed allocation of payments to QFs. PPLICA accepted PP&L's alternative allocation proposal and there is, therefore, no dispute on this issue.

14. Cost Of Service Study: Allocation Of The EDI/IDI Credits. Exception is taken to the allocation of EDI/IDI discounts to all customer classes. Sound cost allocation principles and Commission precedent fully support the allocation of these "costs" to industrial customers.

15. <u>Rate Design: Residential Customer Charge</u>. Exception is taken to the proposed scale back of the Rate RS customer charge. This proposal was not advanced by any party, is unprecedented and disregards the cost of service evidence presented in this proceeding.

III. ARGUMENT

A. Alleged "Excess" Generating Capacity

The most serious error in the Recommended Decision is the adoption of an approximate $33 million excess capacity adjustment. This proposal is not supported by the record, is contrary to prior Commission and Appellate Court precedent and, if approved, would disallow a return on generating facilities which are unquestionably used and useful in providing service to customers.

Concluding that PP&L has 564 Mw of capacity above an OTS-proposed ratemaking reserve margin of 16%, the ALJ has recommended that the Company be denied a return on approximately $239.5 million of its investment in production plant (R.D., p. 30). This recommendation is not only unprecedented in its treatment of various sub-issues, but, if adopted, would make electric utilities extremely reluctant to (1) cooperate fully with alternative energy suppliers, (2) implement programs that foster economic development, (3) initiate cost-effective upgrades to existing facilities and (4) generally take all of the steps necessary to assure reliable service. As the PJM struggles to meet customer demands during a period of extreme weather conditions, this is not the message that should be sent.

A detailed analysis of this matter, including a critique of the positions advanced by the OTS and OCA, may be found in the Company's Initial (pp. 15-59) and Reply (pp. 3-16) Briefs. Because of the page limit imposed on these Exceptions, the Commission is urged to thoroughly review that discussion. As explained therein, and as summarized below, the ALJ's proposed excess capacity finding should be reversed for a number of independent reasons:

- Inconsistency With Rejection Of PP&L's ECR Proposal. The OTS witness who sponsored the adjustment adopted by the ALJ made it clear that his recommendation was contingent upon approval of PP&L's proposal to recover the costs of returning capacity from expiring bulk power sales agreements through the ECR. If that proposal is to be denied, as the ALJ has recommended, then the OTS' excess capacity adjustment must similarly fall.

- Inadequacy Of Recommended 16% Reserve Margin. The 16% reserve margin adopted by the ALJ seriously understates PP&L's reliability needs and lacks evidentiary support. In addition, it is well below the range of values found appropriate for PP&L (22%) and other Pennsylvania electric utilities (e.g., 22%-28%) in the past.

- Improper Inclusion Of QF Output In The Excess Capacity Determination. The 564 Mw of alleged "excess" capacity include substantial quantities (474 Mw - 504 Mw) of QF output which PP&L was required to purchase under PURPA after completing its last major capacity addition (i.e., SSES 2). The inclusion of such output in excess capacity calculations is confiscatory, contrary to the Legislature's goal of promoting the development of alternative energy supplies and inconsistent with prior Commission and Appellate Court precedent.

- Inappropriate Use Of A Prospective Nine-Year "Averaging" Approach. The 564 Mw of alleged excess capacity have nothing to do with test year or rate effective period conditions, but rather represent an average value computed over a nine-year prospective planning period (1995-2003). As such, adoption of the adjustment would deny PP&L a return on capacity which is currently used and useful but which the OTS speculates may become "excess" years from now.

- Insufficient Consideration Of Other Policy Objectives. The 564 Mw figure also includes the capacity resource equivalent of 345 Mw of interruptible load and 90 Mw attributable to cost-effective capacity uprates at SSES 1 and 2. PP&L's interruptible load offerings were designed to spur economic development and its unit uprates provide energy at about 1.5¢ per kilowatthour ("kWh"), or considerably below the Company's avoided cost of energy. The adoption of the OTS' proposed adjustment would obviously dampen PP&L's enthusiasm for such initiatives.

In short, the ALJ's proposed excess capacity disallowance is not only confiscatory and grossly unfair, but creates tremendous disincentives for electric utilities to act responsibly and in the best long-term interests of their customers. The Commission must, therefore, reject this adjustment.

1. Inconsistency With Rejection Of PP&L's ECR Proposal

Because the Recommended Decision denied PP&L's proposal to recover the costs of returning capacity through its ECR (see discussion, infra), the OTS' excess capacity adjustment must be rejected. On this point, the record is clear and undisputed.

To understand and appreciate the interdependence of these two issues, it is necessary to briefly review the manner in which the OTS developed its recommended disallowance. As noted previously, the alleged 564 Mw "excess" does not reflect test year or rate effective period conditions. Instead, OTS witness Metro examined PP&L's projected loads and resources over a nine-year "defined planning period" and, for each of the years in question, determined how many megawatts PP&L might have in excess of an arbitrary 16% reserve margin benchmark.[1/] Mr. Metro then summed the resulting values, divided by nine and came up with an average figure of 564 Mw.

By taking this approach, Mr. Metro explicitly included in his nine-year average the capacity which the Company is currently selling to JCP&L, AE and BG&E. Thus, in calculating PP&L's purported excess capacity for the 1996 winter peak period, he added back the first 189 Mw of JCP&L capacity that will return on January 1, 1996; for the 1997 winter peak period, he included the second 189 Mw of capacity scheduled to return on January 1, 1997 and so forth. To his credit, however, Mr. Metro recognized that it would be entirely inappropriate to base an excess capacity adjustment on capacity which Pennsylvania jurisdictional customers were not paying for. And, for that reason, he made it

---

1/ To the best of PP&L's knowledge, the Commission has never approved a reserve margin as low as 16% for any electric utility.

clear in his direct testimony (OTS St. 5, pp. 27-28) and later on cross-examination that his recommended disallowance was contingent upon approval of PP&L's request that it be granted contemporaneous recovery of the costs of the returning capacity through its ECR (Tr. 1522-1523):

> Q. Let me ask you this question before we get to specific numbers. This nine-year averaging concept is dependent, is it not, on the Commission's adoption of PP&L's proposal that it be allowed to phase in through the ECR the capacity that will be returning from expiring off-system sales? The two are tied together, are they not?
>
> A. The two are tied together in that Mr. Sipics' Exhibit JFS-1 includes those increments of the JCP&L contract coming back in over the [next] five years, and as a consequence of those coming back in I utilized those as net resources available.
>
> Q. But the only way they could come back in, at least and be recognized for jurisdictional rate purposes, would either be through a series of base rate cases or through adoption of Mr. Kleha's proposal that the ECR be used for that purpose; isn't that correct?
>
> A. That's the two ways they could come back into rates, yes.
>
> Q. And it would be inappropriate, would it not, to develop an excess capacity adjustment on the basis of capacity for which Pennsylvania jurisdictional customers were not being asked to pay anything for?
>
> A. If the increments, 189 increments, megawatt increments, did not come back into the system, in my opinion then there would be no excess capacity adjustment.

In its Main Brief to the ALJ, the OTS reaffirmed that its recommended excess capacity adjustment and approval of PP&L's ECR proposal were, in fact, "tied together" (p. 35):

> OTS does not oppose the Company's ECR proposal, since the net capacity resources used to calculate OTS's excess capacity adjustment include the addition of 189 MW of capacity in each of the five years 1996 through 2000 as the JCP&L agreement is phased out.

The ALJ overlooks the linkage between these two issues and, while adopting the OTS' recommended excess capacity adjustment, denies the Company's ECR proposal as "overly innovative and too automatic" (R.D., p. 274). The Recommended Decision would, therefore, use capacity, the costs of which will not be reflected in jurisdictional rates until claimed and approved in subsequent base rate proceedings, to justify the disallowance of a return on capacity which is unquestionably used and useful at the present time. This clearly constitutes reversible error, as even OTS witness Metro appeared to recognize. Furthermore, even if the Company's ECR proposal is approved, the OTS' recommended excess capacity adjustment should be rejected for the reasons set forth below.

2. Inadequacy Of Recommended 16% Reserve Margin

In PP&L's last base rate proceeding, the Commission determined that 22% was a reasonable reserve margin for ratemaking purposes and, armed with that finding, denied the Company a return on 945 Mw of SSES 2 capacity. See Pa. P.U.C. v. Pennsylvania Power & Light Co., 59 Pa. P.U.C. 332 (1985) (the "Unit 2 Case"). In the intervening ten years, PP&L's peak demand has increased by approximately 1555 Mw, or 610 Mw more than the amount found excess in the Unit 2 Case. This is significant because, apart from an extremely cost-effective 90 Mw (jurisdictional) uprate of SSES,[2/] PP&L has not added to the capacity which it owns and operates since SSES 2 was placed in service.

If the 22% reserve margin standard employed in the Unit 2 Case were utilized here, there would be no basis for concluding that PP&L has excess capacity -- even if all of the

2/ As discussed infra, these uprates produce annual cost savings of approximately $8.0 million.

other flaws in the Recommended Decision were ignored. Unfortunately, without further analysis or explanation, the ALJ adopted the 16% reserve margin figure proposed by the OTS (R.D., p. 28). This finding seriously understates PP&L's generating needs and must be rejected.

As explained in the Company's Initial Brief (pp. 42-43), the OTS' proposed reserve margin was not based on any meaningful evaluation of PP&L's load and resources. Rather, and as Mr. Metro candidly admitted, his 16% benchmark was simply designed to provide what he subjectively believed was a sufficient "contingency" or "padding" factor over and above PP&L's installed capacity obligation to the PJM (OTS St. SR5, p. 2). As a result, Mr. Metro never addressed -- and, indeed, effectively ignored -- the specific considerations, enumerated by PP&L witnesses throughout this proceeding, which lead to a very different conclusion.

Planning Uncertainties. Despite the best efforts of PP&L and PJM system planners, each of the three components that ultimately define the Company's required reserves -- load level, available resources and the PJM installed capacity obligation -- is highly uncertain. For example, PP&L's load forecast, which was accepted and utilized by all parties, assumes that peak demands will grow, on average, by approximately 130 Mw per year over the next decade. However, load growth can be and has been far less predictable. In fact, in the early 1990's PP&L's winter peak increased by 313 Mw and 273 Mw in successive years (PP&L St. 16-R, p. 21).

Capacity resources can also change over time in unanticipated ways. Thus, in this case PP&L has reflected, as an available resource, 345 Mw of interruptible load. Yet, as acknowledged by Mr. Metro (Tr. 1517), the Company cannot force an interruptible service customer to actually shed load when it is asked to do so. In fact, if a customer elects to stay on-line for economic or other reasons, PP&L's only recourse is to disqualify that customer from eligibility for interruptible service in the future. Furthermore, because interruptible service contracts are renewable annually, some or all of this resource could be lost if interruptible service customers move off the rate or reduce their interruptible loads. In light of the Company's proposal to make its interruptible service offerings more cost-based, a proposal approved by the ALJ, this is more than just a theoretical possibility (PP&L St. 16-R, pp. 21-22).[3/]

Finally, it is important to note that the Company's installed capacity obligation to the PJM must be satisfied both on a planning basis and on an "after-the-fact" basis. Company witness Sipics described the process as follows (PP&L St. 9-R, p. 5):

> PP&L's minimum 12% PJM reserve requirement is set two years in advance of the planning period. Following the completion of the PJM planning period, "after-the-fact" accounting adjustments are made to PP&L's obligation to reflect actual unit performance and loads. In addition, available capacity is reduced for peak period maintenance. All of these adjustments must be considered in developing an accurate characterization of PP&L's total capacity obligation. Within the last two years, these adjustments have increased PP&L's reserve level required for PJM installed capacity accounting purposes by as much as 5.3 percentage points (351 MW) above its planned obligation.

These planning uncertainties make it incumbent upon PP&L to maintain reserves substantially in excess of its designated PJM minimum requirement.

3/ As discussed infra, there is similarly no guarantee that QFs will continue to perform as they have in the past (PP&L St. 9, pp. 10-11).

Generating Unit Availability During Winter Months. PP&L and its customers derive substantial benefits by virtue of the Company being a winter-peaking utility in a summer-peaking power pool. At the same time, however, PP&L faces meaningful exposure to relatively high unit unavailability during winter months.

In the PJM's reliability calculations, generating unit availability and load are assumed to be independent variables. Yet, as noted by Mr. Sipics (PP&L St. 9-R, p. 5; Tr. 2383-2384), they are not. To the contrary, the same factor -- cold weather -- not only leads to increased customer demands (i.e., home heating), but also enhances the prospect that units will be unable to run due to frozen coal piles, disruptions in the delivery of oil and the interruption of fuel supplies to gas-fired plants. Significantly, this problem was highlighted by Commissioner Hanger in a recently published article evaluating the causes of the January 1994 rotating blackouts. See Public Utilities Fortnightly, May 1, 1995, pp. 27-30.

"Lumpiness". Any assessment of the reasonableness of PP&L's reserve margins must also recognize that large base load capacity additions, such as those constructed by the Company in the 1980s, are inherently "lumpy" and will inevitably lead to a period of temporary capacity surplus.

The Commission has recognized this practical planning consideration on a number of occasions. In the Unit 2 Case (pp. 18-19), the Commission, quoting favorably from the Recommended Decision of Administrative Law Judge Klovekorn in a prior PP&L case, stated:

> Certainly, it is true that capacity cannot be added megawatt by megawatt. Under most circumstances, the addition of a large base load plant plus the vagaries of the economy, which, despite the plethora of

> forecasting models floating around, always seem to undermine any set of assumptions, will result in a utility initially having substantial amounts of capacity in excess of its reserve requirements.

In two subsequent proceedings, the Commission expressly declined to adopt proposed excess capacity adjustments notwithstanding findings that the utilities' reserve margins would exceed the optimum range used for planning purposes. Thus, in Pa. P.U.C. v. Philadelphia Electric Co., Docket No. R-850152 (June 27, 1986) (Order, pp. 36-37), the Commission affirmed Administrative Law Judge Matuschak's determination that a "reasonable increase in reserve capacity must be allowed before excess capacity comes into play". And, in Pa. P.U.C. v. West Penn Power Co., 61 Pa. P.U.C. 711, 737 (1986), where the disparity between actual and optimum reserve margins approximated 11.0%, the Commission reached the same conclusion, reasoning as follows:

> In contrast to the planned, operational reserve margin criteria just discussed is the currently projected, actual reserve margin which results from the vagaries of imperfectly predictable load growth, long lead-time construction programs, and other factors. It is this kind of margin which is, for example, subject to large quantum changes when a large unit is added or withdrawn.

What distinguishes this proceeding from the Unit 2 Case is that the "excess" which the opposing parties find objectionable is not attributable to SSES 2 or, for that matter, any other capacity owned and operated by PP&L. Instead, and as the record in this case confirms (Tr. 2367-2368), the "lump" created by SSES 2 would have been fully absorbed by now but for the unavoidable purchase by PP&L in later years of QF output. Consequently, if QF output is to be recognized as an available capacity resource, which PP&L believes would be inequitable and inappropriate for the reasons set forth in the next section of these

Exceptions, then "lumpiness" remains a valid consideration in establishing the upper end of PP&L's allowable reserve margin range.

In view of the foregoing, a reserve margin range from 12% (PP&L's "before-the-fact" installed capacity obligation to the PJM) to at least 20% can be fully justified on reliability grounds alone by simply recognizing planning uncertainties (e.g., the 5.3% "after-the-fact" installed capacity obligation adjustment made in 1994) and "lumpiness" (i.e., even OCA witness Kahal would allow a 3% "lump") (PP&L St. 16-R, pp. 25-26). Such a finding would still fall below the reserve margins previously allowed Duquesne Light Company (18%-22%), Pennsylvania Power Company (20%-28%), PECO Energy Company (22%) and West Penn Power Company (28%-39%).[4/]

3. Improper Inclusion Of QF Output In The Excess Capacity Determination

In compliance with its obligations under PURPA, the Company presently purchases substantial output from QFs. Even though virtually all of PP&L's agreements with QFs were executed after its last major capacity addition (SSES 2) was substantially completed, OTS witness Metro nonetheless utilized the QF output as available capacity to, in effect, displace pre-existing generating investment which otherwise would be found to be used and useful. Although the ALJ does not address this issue in his Recommended Decision, he implicitly endorses the OTS' approach by adopting its proposed adjustment.

4/ See Pa. P.U.C. v. Duquesne Light Co., 66 Pa. P.U.C. 518 (1988); Pa. P.U.C. v. Pennsylvania Power Co., 93 PUR4th 189 (1988); Pa. P.U.C. v. Philadelphia Electric Co., 74 Pa. P.U.C. 1 (1990); Pa. P.U.C. v. West Penn Power Co., 61 Pa. P.U.C. 711 (1986).

The treatment of QF output is critical to the outcome of this case. Indeed, if QF output is not included in calculating the Company's available capacity resources, there is no basis for concluding that PP&L has excess capacity because its reserve margins in the future test year and year after would satisfy even the inadequate 16% benchmark recommended by the OTS and adopted by the ALJ (Tr. 1524). However, the resolution of this issue also has implications that extend far beyond this proceeding. Stated simply, if the OTS' position is adopted, it will send a clear message to all of Pennsylvania's electric utilities to minimize the amount of QF capacity on their systems regardless of other economic or public policy considerations (PP&L St. 16-R, pp. 29-30).

PP&L submits that it would be patently unreasonable and confiscatory to deny it a return on pre-existing plant investment solely because it was required, by PURPA and the Commission's regulations, to purchase output from QFs. This is not a case where a utility continued to add capacity long after the availability of QF output became known. Rather, as previously noted, PP&L's contracts with QFs were not executed until after SSES 2 was virtually completed. <u>Consequently, if PP&L has any excess capacity, the QFs are unquestionably the cause of that excess</u>.

Moreover, the Commission was well aware at the time that the Company did not need the QF output for capacity purposes when it accepted contracts based on PP&L's energy-only avoided costs (PP&L St. 16-R, p. 30). In fact, the Commission specifically noted that no capacity payments were involved: "Since these payments are not for capacity, there is nothing to be 'capitalized'." <u>See</u> <u>Re Pennsylvania Power & Light Co. et al.</u>, 61 Pa. P.U.C. 577, 585 (1986). However, for PJM installed capacity accounting purposes, the Company elected to claim QF output as capacity, thereby maximizing its value for the benefit of

PP&L's customers. It would simply be unfair to now penalize PP&L for a prudent management decision designed to enhance the effective utilization of its resources.

Finally, PP&L has no control over QFs. As OTS witness Metro acknowledged (Tr. 1519), significant changes in fuel prices, such as were experienced in the 1970s and early 1980s, or other factors could render the continued operation of QFs uneconomic. In fact, one of the QFs from which the Company purchases power recently declared bankruptcy (Tr. 1520). While PP&L is not impugning the manner in which QFs have performed to date, their future operation is problematic.

In his direct testimony (OTS St. 5, pp. 16-17), OTS witness Metro offered five reasons why he believed QF output should be recognized in a reserve margin calculation. Although the Company responded to each of those reasons individually (PP&L St. 16-R, pp. 32-33), the essence of Mr. Metro's position may fairly be reduced to the proposition that QF output should be counted "because it's there and can be used". This, however, simply begs the issue. Indeed, in addition to being confiscatory, Mr. Metro's treatment of QF output is contrary to the Legislature's goal of promoting the development of alternative energy supplies and is inconsistent with prior Commission and Appellate Court precedent.

Initially, Mr. Metro's position cannot be reconciled with Section 523 of the Public Utility Code (66 Pa.C.S. § 523). Section 523 is entitled <u>Performance factor consideration</u> and expressly directs the Commission, in its ratesetting function, to take into account, amongst other things:

> (4) Action or failure to act to encourage development of cost-effective energy supply alternatives such as conservation or load management, cogeneration or small power production for electric and gas utilities.

Through Section 523, the Legislature created ratemaking incentives designed to reward utilities for their efforts to promote cost-effective cogeneration or small power production projects. By utilizing QF output to justify an excess capacity adjustment, the Recommended Decision would penalize, not reward, PP&L.

Moreover, Mr. Metro's treatment of QF output is inconsistent with prior interpretations of the purpose and scope of Section 1323(c) of the Code (66 Pa.C.S. § 1323(c)). Section 1323(c) creates an eight-year window during which the Commission cannot include QF output in determining whether a utility has excess capacity. Because the eight-year window has closed as to all of the Company's QF output, Mr. Metro apparently concluded that such capacity was now fair game and could be recognized in calculating PP&L's reserve margins. The Company strenuously disagrees.

In 1987, the Commission issued a proposed Statement of Policy on the Treatment of Purchases of Capacity from Qualifying Facilities in Excess Capacity Determinations (the "Policy Statement"). The Policy Statement, which was published for comment in the Pennsylvania Bulletin on July 18, 1987 (Vol. 17, No. 29, pp. 3035-3038), provided that, in cases where Section 1323(c) did not control (i.e., where, as here, the eight-year window had closed), the Commission would not consider QF output in addressing excess capacity issues other than in those instances where a utility imprudently failed to cancel or defer the construction of a new generating unit, the need for which had been displaced. In support of its position, the Commission reasoned as follows:

> If a utility is unwilling to negotiate with a developer, legal recourse is available to the developer by the filing of a formal complaint with the Commission. However, the time and expense that such a formal proceeding necessarily entails is most often sufficient to discourage a

> developer from pursuing its remedy. Therefore, it is important that some assurance be provided to utilities that their voluntary entrance into an agreement with the developer of a QF will not place the utility's investment in its own generating units unreasonably at risk. An excess capacity adjustment made, in part, on the basis of the availability of QF capacity would place a utility's investment at risk, and would be likely to discourage continued development of qualifying facilities.
>
> On the other hand, it would not appear reasonable to wholly insulate a utility from any consideration of capacity provided by QFs. Public utilities are under a continuing duty to supply adequate service at the lowest reasonable cost and therefore are obliged to cancel or defer the construction of additional capacity where firm, reliable capacity becomes available from QFs at a cost equal or lower than that which the utility otherwise would incur.
>
> * * *
>
> We conclude from the foregoing discussion that a policy of excluding consideration of executed purchase power agreements with qualifying facilities from the reasonable reserve margin and economic benefits tests of Section 1323 may be warranted in most cases. The exception to this general policy would be situations where purchases of firm and reliable capacity, under long term contract, have offset the need for a utility's own generating unit, and where the utility nevertheless failed to defer or cancel the construction of its own generating unit when cancellation or deferral would have represented the most economical choice for the utility's ratepayers.

Although the Policy Statement was never finalized, the Commission has ruled to the same effect in a number of proceedings involving requests by utilities that it (1) pre-approve the rate recovery of payments to be made to QFs and (2) declare that the addition of QF capacity pursuant to such agreements will not be considered in future excess capacity determinations. For example, in Petition of West Penn Power Co., 1987 Pa. PUC LEXIS 153 (1987), industrial intervenors contended that the Commission lacked the authority to exclude QF output from excess capacity analyses where Section 1323(c) did not apply. In rejecting this assertion, the Commission held:

> Contrary to arguments by Armco, Inc. and Allegheny Ludlum Corporation, the General Assembly has not mandated the inclusion of PURPA 210 generating capacity in those cases where the capacity is not expressly to be excluded. In fact, legislation at 66 Pa.C.S. § 523(b)(4) specifically directs that the Commission encourage the development of cogeneration and small power production, and that utilities failing to cooperate be subject to ratemaking penalty.

The Commission, citing its proposed Policy Statement, therefore granted the relief sought by West Penn.

On appeal, the OCA argued that the Commission's declaration violated the due process rights of West Penn's customers because they had not been provided adequate notice of the proceeding. While the Commonwealth Court agreed, the Court also made it clear that the Commission had the authority to reach the conclusions it had regarding the proper treatment of QF output:

> [B]ecause the commission has not adopted the Policy Statement, the commission's order in this case is the administrative action that affects the ratepayers' rights regarding the excess capacity treatment of the Milesburg project capacity, and hence is adjudicatory in nature. This conclusion does not mean that the commission does not have the power to decide to disregard the Milesburg project capacity in excess capacity determinations involving West Penn's existing capacity . . .

Barasch v. Pa. P.U.C., 119 Pa. Cmwlth. 81, 109-110, 546 A.2d 1296, 1309 (1988) (emphasis added); see also Re West Penn Power Co., 71 Pa. P.U.C. 60, 78 (1989); Pennsylvania Electric Co. v. Pa. P.U.C., 166 Pa. Cmwlth. 413, 426, 648 A.2d 63 (1994) ("[I]f QF capacity is excess, the ratepayers, not the utility or the QF, are required to assume the burden of paying for capacity not needed leading to increased rates.").

In view of the foregoing, the Commission should conclude, as a matter of sound regulatory policy and simple equity, that QF output may not be included in the determination of PP&L's reserve margins and used to disallow a return on pre-existing investment. And, based on that finding, the ALJ's proposed excess capacity adjustment should be rejected.

4. **<u>Inappropriate Use Of A Prospective Nine-Year "Averaging" Approach</u>**

As previously pointed out, the 564 Mw figure developed by Mr. Metro is based, in part, on projections that reach out as far as the winter of 2003-2004 (OTS Ex. 5). There are several problems with this approach. First, and putting aside the JCP&L capacity which begins to return on January 1, 1996, there is additional generating capacity that PP&L has not claimed in this case which nonetheless finds its way into Mr. Metro's nine-year average -- most prominently, the 129 Mw and 132 Mw currently being sold to AE and BG&E, respectively (PP&L Ex. JFS-1). Secondly, if the past is any guide, it is highly improbable that today's projections will prove to be letter-perfect. Future customer demands may exceed expectations; available resources may not be present in the amounts assumed. Consequently, and in view of the foregoing factors, the practical effect of the ALJ's recommended adjustment is to penalize PP&L today for capacity which it is not claiming in rates and/or which the OTS merely speculates <u>may</u> become "excess" years from now.

5. **<u>Insufficient Consideration Of Other Policy Objectives</u>**

Any evaluation of the "usefulness" of PP&L's generating line-up must take into account the fact that not all capacity is added for reliability purposes. The most obvious example of this is the QF output which PP&L purchased pursuant to Federal mandate. But, there are others.

As noted previously, approximately 90 Mw of PP&L's alleged "excess" may be traced to capacity uprates at SSES 1 and 2. These uprates provide energy at about 1.5¢ per kilowatthour ("kWh"), or far below the Company's avoided cost of energy of 2.8¢ per kWh. The SSES uprates will reduce annual energy costs by approximately $8.0 million[5/] and were, therefore, properly undertaken regardless of PP&L's then current or prospective installed capacity situation. Another 345 Mw of capacity resources is due to PP&L's implementation during the 1991/1992 planning period of interruptible service options designed to encourage economic development in central-eastern Pennsylvania. Unfortunately, as Company witness Hieronymus pointed out (PP&L St. 16-R, pp. 37-38), the opposing parties chose to disregard or substantially discount these non-reliability related factors and, by doing so, lost sight of important policy considerations:

> Q. Do you have any other comments that you wish to make concerning the approach used by the OTS and OCA witnesses in assessing the need for PP&L's capacity?
>
> A. Yes. I simply would like to note that adherence to simple calculations of after-the-fact reserve margins for determining whether PP&L is entitled to be paid for its owned and leased capacity could create adverse incentives. If a utility had believed over the past decade that it was going to lose a great deal of money for every megawatt of "capacity" that it created, it would have had a powerful incentive to minimize the amount of additional capacity on its system regardless of other economic or policy considerations. Decisions regarding QF contracts, load management and unit uprates would have been scrutinized from that perspective. In fact, the utility likely would have sought methods of reducing capacity reserves including plant retirements and load growth.
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> The OTS and OCA witnesses claim disinterest in why reserves are what they are, and look only to whether the achieved reserve margin fits into a narrow range above the PJM minimum. I do not believe that

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5/ 90 Mw x 8760 Hours = 788,400 Mwh x 1000 = 788,400,000 kWh x 80% Capacity Factor = 630,720,000 kWh x 1.3¢ Savings Per kWh = $8,199,360.

this is or should be viewed as an appropriate public policy for Pennsylvania.

The foregoing concerns are nowhere addressed in the Recommended Decision and the ALJ's proposed excess capacity adjustment should be rejected for this reason as well.

6. A Postscript

During the recent heat wave that gripped much of the nation, PP&L and the PJM struggled to meet customer demands. As reported in an article which appeared in the August 4, 1995 edition of the Philadelphia Inquirer (a copy of the article has been attached hereto as Appendix "A"), all available generation was dispatched and massive amounts of power were imported from the Midwest and the New York Power Pool. The PJM experienced record peak demands and PP&L shattered its previous all-time summer peak by 383 Mw. Yet, because of prudent planning, the lights did not go out and, perhaps more importantly, critical air-conditioning load was not lost.

In the Public Utilities Fortnightly article alluded to earlier, Commissioner Hanger observed: "When a system is stressed, reserve margins shrink precipitously, and the margin for reliable operation may be just a few percentage points of total capacity." That appears to have been the case in the past several weeks. The question thus becomes whether the cost of that needed margin is worth the reliability it ensures. In the case of the 564 Mw of capacity that the ALJ would exclude, the cost to the average residential customer approximates only 2¢ per day. PP&L respectfully submits that this is a price well worth paying.[6/]

6/ $33,047,000 Revenue Adjustment (Per OTS Main Brief, p. 35) x .38387 (Residential Class Production Plant Allocation Per Factor D10 at PP&L Ex. JMK-2, p. 200)

(continued...)

B. Cost Of Common Equity

The ALJ has proposed an equity allowance for PP&L of only 10.9% (R.D., p. 179). As a review of the Recommended Decision reveals, this figure is based solely on the DCF analyses submitted by the three opposing party rate of return witnesses who appeared during the course of this proceeding and purportedly was derived by simply taking the midpoint of the dividend yield and growth rate ranges which they presented. This recommendation is woefully inadequate in theory and in result and must be rejected.

As a threshold matter, the ALJ's proposed 10.9% equity allowance cannot be reconciled with recent Commission cost of capital findings. For example, within the past month the Commission determined that the cost of equity for a water utility was 11.25%. Pa. P.U.C. v. Pennsylvania-American Water Co., Docket No. R-00943231 (July 24, 1995); see also Pa. P.U.C. v. Roaring Creek Water Co., Docket No. R-00943177 (May 31, 1995) (11.0%). And, last December, the Commission awarded West Penn Power Company -- a utility with an A+ bond rating and no nuclear investment exposure -- an equity return rate of 11.5%. Pa. P.U.C. v. West Penn Power Co., Docket No. R-00942986, 1994 Pa. PUC LEXIS 144 (December 29, 1994).

That the ALJ's recommendation is far too low is also confirmed by recent regulatory decisions from other jurisdictions. See, e.g., Re Portland General Electric Co., 160 PUR4th 201, 271 (1995) (11.6%); Re Hawaii Electric Light Co., 159 PUR4th 290, 325 (1995) (11.5% prior to upward adjustment for company-specific risk factors); Re Sierra Pacific

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6/(...continued)
÷ 10.9 Billion Kilowatthours (Residential Sales Per PP&L Ex. JMK-2, p. 199) = 1.2 Mills Per kWh x 500 kWh Per Month = 60¢ ÷ 30 Days = 2¢ Per Day.

Power Co., 158 PUR4th 217, 241-242 (1995) (setting authorized equity returns for California's electric utilities ranging from 11.3% to 12.1%); Re Commonwealth Edison Co., 158 PUR4th 458, 521 (1994) (12.28%); Re Madison Gas & Electric Co., 158 PUR4th 168, 178 (1994) (11.7%); Re Wisconsin Power & Light Co., 158 PUR4th 80, 93 (1994) (11.5%).

How the ALJ arrived at such an unreasonably low result is not difficult to discern. First, and as noted previously, he relied exclusively on the DCF method. For the past several years, utilities in Pennsylvania have argued, largely unsuccessfully, that the mechanical application of the DCF method, as practiced in this case, will produce figures that understate the cost of equity. The reasons for this were thoroughly explained by Mr. Moul in his direct (PP&L St. 12, Appendix C, pp. C-4 and C-5) and rebuttal (PP&L St. 12-R, pp. 12-15) testimony and are summarized in the Company's Initial Brief (pp. 225-226). Significantly, Mr. Moul is not alone in this view. Indeed, a growing number of other commissions have come to the same conclusion.

For example, in a recent case the Indiana Utility Regulatory Commission discussed this problem as follows:

> In determining a common equity cost rate, we must again recognize the tendency of the traditional DCF model, relied on heavily by Mr. Bolinger, to understate the cost of common equity. As the Commission stated in Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, "the unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore requires an upward adjustment based largely on the expert witness's judgment."
>
> * * *
>
> It is recognized that "there are difficulties in making a good DCF calculation whenever a utility's stock sells, for whatever reason, above book value." Niagara Mohawk Power Corp. (NY PSC 2/2/93), 140

PUR4th 481, 491. This phenomenon was also discussed in Whittaker, "The Discounted Cash Flow Methodology: Its Use In Estimating A Utility's Cost of Equity," 12 Energy L.J. 265, 281-282 (1991), where it is stated:

> The DCF methodology presumes to produce the "market required" return of equity, that is, the "cost of equity" on the market value -- not the book value -- of a company's stock. Unless the market price of a utility's stock equals its book value, the unmodified application of the market-oriented DCF results to a net original cost (book value) rate base understates the earnings necessary to satisfy the investor-required (expected) return.
>
> Thus, if the traditional DCF model is strictly applied to an original cost rate base, the investor could earn the cost of capital only if the investor paid no more than book value for the stock.

The Iowa Utilities Board agreed in Re Interstate Power Co., 152 PUR4th 377, 382-83 (1994):

> The Board generally relies on the DCF model for the initial analysis to determine the cost of equity and uses a risk premium analysis as a check on the validity of the DCF analysis. In *Iowa Electric Light and Power Company*, Docket No. RPU-89-9, "Final Decision and Order" (October 25, 1990), the Board stated: "[T]he DCF model may understate the return on equity in some circumstances. This is particularly true when the market is volatile and the company in question has a market-to-book ratio in excess of one." Those conditions exist in this case (Ex. 17, Sch. 2, p. 3). The DCF results do not overlap with the risk premium analysis because the DCF model yields extremely low results.
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> * * *
>
> In this case, the DCF approach underestimates the cost of equity needed to assure capital attraction during this time of market uncertainty and volatility . . . The Board will, therefore, give preference to the risk premium approach . . .

See also Maui Electric Company Ltd., 153 PUR4th 437, 473 (1994) ("we agree with MECO that there is currently a downward bias in the DCF model"); Re Commonwealth Edison Co., 158 PUR4th 458, 520 (1995) ("[T]he presentations made by Messrs. Gorman, LeLash and Kahal lead to determinations which understate Edison's cost of equity; e.g., use by all three Intervenor witnesses of an annual DCF model, which has been explicitly rejected by this Commission.").

Well-entrenched regulatory policies die hard and the reliance on historic practices is understandable. Yet, at some point circumstances dictate a fresh look. When a particular approach no longer generates credible results, as in the case here, the time has come for consideration of other methods. This is not to say that the DCF method should be abandoned or that the Commission need chart a radically different course. Rather, PP&L simply asks that the Commission keep an open mind and, in the exercise of its sound discretion, recognize that other equity cost rate methodologies should not be systematically ignored.

Secondly, and even if the Commission feels constrained to rely exclusively on the DCF method, the ALJ's proposed 10.9% equity allowance must nonetheless be rejected. The principal flaw in the ALJ's analysis rests in his averaging of results. As the Commission has properly held in the past, this technique only invites abuse: "[c]ost of equity recommendations should be based upon specific market based costs, rather than by a method which averages the recommendations of the various parties." Pa. P.U.C. v. Columbia Gas of Pa., Docket No.. R-891468 (September 20, 1990) (Order, pp. 118-119).

Even in the most extreme situation, the averaging of results is a poor substitute for informed judgment and thoughtful analysis. In this proceeding, the use of such an approach is especially egregious. As noted earlier, the ALJ chose to average the findings of the OTS, OCA and PPLICA witnesses and, in so doing, gave no weight whatsoever to the evidence submitted by the Company. Consequently, the Recommended Decision does not act to "decrease expert witness bias", as suggested (R.D., p. 171), but instead tilted the scales decisively toward those who, from the outset, have aggressively opposed PP&L's requested rate increase.

Moreover, and wholly apart from the issue of witness bias, the ALJ's averaging of results is at odds with his stated purpose. At page 163 of the Recommended Decision, the ALJ indicates that he believes barometer group data should be given "slightly less weight" than data for PP&L itself. However, his use of the midpoint of the average dividend yields proposed by the opposing party witnesses has exactly the opposite effect. This is because Messrs. Kahal (OCA) and Baudino (PPLICA) produced dividend yields for two different barometer groups. Accordingly, an average of their respective dividend yield findings accords two-thirds weight to barometer group data and only one-third weight to PP&L data.

Compounding this problem is the fact that the 7.5% OCA dividend yield set forth on page 164 of the Recommended Decision appears to be the rounded average of Mr. Kahal's two barometer group findings and, as such, completely disregards his recommended DCF yield for PP&L. Indeed, if only equal weight had been given to Mr.Kahal's 8.46% yield for PP&L, the midpoint of the ALJ's dividend yield range would have approximated 7.96%, or 33 basis points higher than his 7.63% recommendation. If "slightly less weight" were accorded the barometer group data, as the ALJ implies would be appropriate, the figure obviously would be even higher.

The final flaw in the ALJ's averaging of results is attributable to the fact that all three opposing party witnesses developed proposed yields for PP&L and Mr. Moul's barometer group. Rather than inputting multiple (i.e. initial and updated) dividend yield values for PP&L and the same group of utilities, the ALJ should have considered only the most current yield data presented by the close of the record:

Baudino Barometer Group (PPLICA St. 8, p. 32)	7.35%
Kahal Barometer Group (OCA St. 1A, Sch. MIK-6, p. 1 Update)	7.41%
Moul Barometer Group (OCA St. 1A, Sch. MIK-4, p. 1 Update)	7.52%
PP&L (OCA St. 1A, Sch, MIK-7, p. 1 Update)	8.46%

Utilizing the midpoint of the range of values, which also has the effect of giving equal weight to PP&L and barometer group data, produces an unadjusted dividend yield of 7.91%.

The ALJ's recommended 3.15% growth rate, which similarly is based on an averaging or midpoint approach, is deficient for many of the same reasons that undermine his dividend yield finding. More importantly, however, his proposed 10.9% equity allowance, <u>even</u> <u>if</u> <u>achieved</u>, would not generate anything near the level of growth which he concluded investors could reasonably expect. This is confirmed by the following table, which is comparable in format to that developed by Mr. Moul in his rebuttal testimony (PP&L St. 12-R, p. 6) and reproduced in the Company's Initial Brief (p. 229):

Recommended ROE	PP&L Book Value	Earnings Per Share	Dividends Per Share	Amount Retained Per Share	Calculated Growth Rate
10.9%	$15.79	$1.72	$1.67	$0.05	0.32%

Finally, PP&L must except to the ALJ's conclusion that managerial performance, and particularly PP&L's unparalleled efforts to maintain rate stability over the past ten years, may be ignored because the Company did not include "a quantified request for an equity bonus" in its initial filing (R.D., p. 176). In fact, PP&L has not sought a specific "equity bonus" -- it has merely asked that the Commission consider its accomplishments and grant it an equity allowance at the upper end of the zone of reasonableness (see PP&L Initial Brief, p. 216). More to the point, Section 523 of the Code does not obligate a utility to quantify a potential "reward" (R.D., p. 176). Instead, it directs the Commission to consider evidence regarding "the efficiency, effectiveness and adequacy of service" and to make appropriate rate adjustments in response thereto. That evidence was presented by PP&L in its initial filing through the direct testimony of Mr. Hill (PP&L St. 1, pp. 4-6) and should not have been disregarded by the ALJ.

C. Depreciation Of Older Fossil-Fired Generating Units

The ALJ rejected PP&L's proposal to shorten the depreciable life spans of its older fossil-fired generating units[7/] to reflect the substantial risk that those facilities will not remain in service beyond the year 2003, when stringent new air quality standards take effect. Nonetheless, the ALJ acknowledged that PP&L's overall assessment "is correct, in

7/ These units consist of Sunbury 1, 2, 3 and 4 ("Sunbury"), Martins Creek 1 and 2 ("Martins Creek") and Holtwood 17 ("Holtwood").

principle;" its selection of 2003 as a deactivation date "might be right;" and his decision was "a difficult call" (R.D., pp. 124-125). The caveats and qualifications that the ALJ attached to his recommendation underscore the substantiality of the evidence PP&L presented. That evidence fully supports the Company's position, as explained below and in its Initial (pp. 167-180) and Reply (pp. 75-79) Briefs.

PP&L's depreciation expense claims for Sunbury, Martins Creek and Holtwood reflect a deactivation date of 2003, which results in life spans that are, respectively, 6, 12 and 7 years shorter than those currently being used to depreciate these facilities, but somewhat longer than the life spans approved in the Company's Unit 2 Case. The deactivation dates used in that case were 1994 (Holtwood), 1995 (Martins Creek) and 2000 (Sunbury). In 1988, in conjunction with other depreciation changes which were made outside of a base rate proceeding, the Commission approved PP&L's proposed extension of the depreciable lives of its older fossil-fired units to reflect deactivation dates of 2009 (Holtwood), 2015 (Martins Creek) and 2010 (Sunbury) (PP&L Initial Brief, pp. 167-168).

When the 1988 revisions were made, the Company anticipated that standard life extension techniques would make it economically justifiable to continue to operate the older fossil-fired units until the extended deactivation dates. However, at that time, the Company could not have foreseen the substantial costs that would be required to comply with the 1990 Clean Air Act Amendments ("CAAA"). Those costs dramatically altered the economics of life extension for the older fossil-fired units. In fact, the projected CAAA compliance costs would almost double the depreciated original cost of those units (PP&L Initial Brief, p. 168).

The proposed deactivation date of 2003 is a watershed year. By that time, PP&L will have to achieve final compliance with stringent nitrogen oxide ("NO_x") limitations imposed under Title I of the CAAA and expects to have to make substantial reductions in emissions of "air toxics" as mandated by Title III of the CAAA. Simply stated, by the year 2003, PP&L either must have deactivated its older fossil-fired units or have made significant investments to achieve environmental compliance.

The operation of the older fossil-fired units beyond 2003 is highly uncertain. Indeed, the following factors make it unlikely that the investments necessary for life extension will be economically justified:

- These units were designed for 30 to 40 years of operation and currently are between 40 and 45 years old. Consequently, significant repairs and replacements -- other than the installation of pollution control equipment -- will be needed.
- These relatively old power plants produce electricity less efficiently than newer plants and, therefore, have higher fuel and operating costs.
- As previously explained, a significant number of environmental issues are expected to affect power plants in general and coal-fired power plants in particular around the year 2003. Compliance with anticipated CAAA standards will require the installation of two different emissions control systems.
- The units are individually relatively small (net generator ratings are between 73 Mw and 150 Mw). Therefore, there are few economies of scale to make equipment replacements and environmental retrofits less economically burdensome.

The full impact of Title I of the CAAA on coal-fired plants in Pennsylvania did not come into focus until September 27, 1994, when a major milestone in the CAAA implementation process was achieved. On that date, the member states of the Ozone Transport Commission, which includes Pennsylvania, executed the Memorandum Of

Understanding On The Development Of A Regional Strategy Concerning The Control Of Stationary Source Nitrogen Oxide Emissions ("MOU"). With the adoption of the MOU, it became clear that the magnitude of NO_x reductions that would have to be achieved would require major capital additions for emission controls at the Company's older fossil-fired units (Tr. 1934).

Based upon information provided by the MOU, PP&L was able to prepare detailed analyses of the economic feasibility of making pollution-control retrofits at the older fossil-fired units. These analyses clearly showed that committing to the substantial investment needed to comply with the CAAA -- which is essential if those units are to remain in operation beyond 2003 -- could not be justified as a prudent investment at this time (PP&L Initial Brief, pp. 176-177).

For the reasons set forth above, the deactivation dates proposed by PP&L to calculate depreciation expense for its older fossil-fired units are totally justified. The Company's proposal is consistent with the concept that current customers should bear prudent costs incurred on their behalf. To ignore the probability of deactivation in 2003 would put future customers unnecessarily at risk to pay for the recovery of invested capital that is no longer providing current service to them.

Despite the substantial evidence adduced by PP&L, the ALJ did not accept the Company's proposed life spans because, in his view, it was not "certain" that the older fossil-fired units would be deactivated in 2003 and "in this instance, uncertainty works against PP&L" (R.D., p. 125). In fact, very few things are "certain" in depreciation analysis -- judgments must be made all the time regarding future operations, technological advances and the like. Unfortunately, however, the ALJ misperceived the significance of "uncertainty" in the context of determining reasonable depreciable life spans.

Far from working "against PP&L," as the ALJ assumed, "uncertainty" as to the future operability of the older fossil-fired units tips the evidentiary balance in PP&L's favor. Well-accepted depreciation practices dictate that <u>all</u> potential causes of retirement should be reflected in life span analysis. Real and substantial risks to the continued operation of a facility -- such as those to which the older fossil-fired units will be exposed in 2003 -- represent a logical terminus for the life spans used in calculating depreciation expense. Failure to adhere to this depreciation principle would understate PP&L's depreciation expense, in the near term, and violate the concept of inter-generational equity, in the long-term, by substantially increasing the probability that customers in the future would have to pay for the capital recovery of generating units that are no longer providing service. Indeed, principles of inter-generational equity would dictate the adoption of the Company's proposed life spans <u>even if it were assumed that the lives of the older fossil-fired units would be extended beyond 2003</u>.

Under the approach recommended by the ALJ, current customers would benefit from an approximate $15.3 million per year <u>reduction</u> in depreciation expense between 1996 and 2003 (R.D., p. 126). However, the assumed life extensions needed to make such a reduction in annual depreciation expense possible would be purchased at the expense of <u>future</u> customers, whose revenue requirement burden would nearly <u>double</u> because of the cost of CAAA capital additions going into service by 2003. Stated another way, use of the longer life spans recommended by the ALJ would defer approximately $122 million of capital recovery ($15.3 million per year for 8 years) to the period from 2004 to the end of the extended lives of the older fossil-fired units. However, during the same post-2003 period, customers would also bear approximately $30 million per year of additional revenue requirement associated with CAAA capital additions (PP&L Initial Brief, pp. 172-173).

These figures clearly demonstrate why the Company's proposed life spans are appropriate whether or not the older fossil-fired units are retired in 2003. If retirement in fact occurs in that year, then the shorter life spans will have properly distributed capital recovery over those units' actual service lives. If post-2003 operation comes to pass, then using the shorter life spans to calculate annual depreciation until the expenditures necessary for life extension have been made will result in a more levelized distribution of revenue requirement over the entire period those units are providing service to customers.

Regulatory commissions in a number of jurisdictions have recognized that life extension should not be used to reduce depreciation expense until the necessary investment has been reflected in the utility's rate base. For example, in Re Public Service Company of Indiana, Inc., 112 PUR4th 94, 148 (1990), the Indiana Commission held as follows:

> [The Consumers Counsel witness] is, in essence, recommending that we accept such extended retirement dates (i.e., the benefits of the [life extension] program) without recognizing, in setting the depreciation rates for such units, the costs to achieve those extended life benefits. We reject such recommendations as being unreasonable and resulting in an improper matching of costs and benefits.

Accord Petition of Indiana Michigan Power Company, 1993 Ind. PUC LEXIS 460, (November 12, 1993); Application of Central Power & Light Co. For Authority To Change Rates, 1990 Tex. PUC LEXIS 233 (October 19, 1990) ("In calculating their depreciation rates, CPL and the Staff used the life to refurbishment or repowering, and eliminated the additions related to refurbishment or repowering. This approach should be adopted in this case.").

In Pa. P.U.C. v. York Water Co., 78 Pa. P.U.C. 87, 109-110 (1993), this Commission similarly refused to recognize, for depreciation purposes, the extended lives of water storage basins until the investment needed to keep those basins in operation had actually been made. In so doing, the Commission accepted York's position on this issue, which was summarized in its Final Order, as follows:

> The Company further argues that since construction to extend the life of the basin has not yet begun, changing service life at this time will misstate depreciation expense and will unfairly impose costs on future ratepayers. Thus, the benefits of any off-setting extension of lives that will be created by the actual construction should be reflected at the same time as the construction is reflected in rates.

The ALJ acknowledged that coordinating the use of longer depreciable lives with the investments necessary to achieve them is proper. However, he decided that the principle should not be applied in this case simply because adopting a 2003 deactivation date would yield shorter depreciable lives than those already in use (R.D., p. 124):

> PP&L is correct, in principle, but I feel it is wrong in this particular circumstance. If we were dealing with an extension of their lifetime, PP&L will be in a better position to present its argument. Then the argument would be that 2003 should remain the expected lifetime until the investment is made which is necessary to extend the life to these plants. This would, perhaps, be a proper coordination of capital investment and depreciation. However, the lifetimes are now set to be longer. These longer lifetimes may depend on further investment but, in any case, longer lifetimes are the status quo. PP&L is seeking to change that status quo.

Unfortunately, the ALJ has misperceived the "status quo." Although PP&L's existing rates reflect depreciable lives of the older fossil-fired units that extend beyond 2003, those lives cannot be achieved unless the Company makes capital additions, prior to 2003, of a magnitude approaching the depreciated original cost of those units.[8] In short, the "status quo" would require the older fossil-fired units to be removed from service in 2003. "Life extension" is required if the units are to remain in service after that date. Accordingly, the distinction the ALJ tried to draw simply does not exist.

D. Nuclear Decommissioning Costs: Contingency

The Company's claim for nuclear decommissioning costs was based on the results of a site-specific study of SSES 1 and 2 prepared by Mr. Thomas S. LaGuardia, President of TLG Services, Inc.[9] Consistent with well-accepted analytic methods, Mr. LaGuardia incorporated an experience-based factor derived from actual decommissioning projects, which he denominated a "contingency." This aspect of his study is widely used and has been approved by the FERC and numerous state commissions as a reasonable component of a decommissioning cost estimate. Indeed, this Commission has twice approved decommissioning expense claims that included a "contingency" factor (PP&L Initial Brief, pp. 129-137).

8/ Significantly, the need for and likely cost of such additions were not contested to any meaningful extent (PP&L Initial Brief, pp. 171-172).

9/ TLG and Mr. LaGuardia have extensive experience in planning and managing nuclear decommissioning projects; had a lead role in decommissioning the Shippingport reactor; and have been retained by the NRC, the Department of Energy and the Atomic Industrial Forum to prepare studies and treatises on nuclear decommissioning and decommissioning cost estimation (PP&L Initial Brief, p. 125).

The ALJ has recommended the disallowance of the contingency apparently based on the mistaken belief that it was simply a "safety factor" tacked on to Mr. LaGuardia's best estimate of SSES decommissioning costs (R.D., p. 99). That is not the case. Rather, as used by Mr. LaGuardia, a "contingency" plays an integral role in the estimation process and is <u>not</u> a mere after-the-fact "adder."

More specifically, the "contingency" component of Mr. LaGuardia's estimate represents the costs of program problems that have a high probability of occurrence but which <u>have not been reflected in the basic estimate</u>. Examples include schedule slippage (leading to overtime or project extensions), weather delays, labor strikes, worker injuries, material shipping problems, equipment breakdowns, regulatory inspections and hazardous materials handling (PP&L St. 13, pp. 22-23).

The inclusion of a contingency in the cost estimation process for both the construction and dismantling of projects is well accepted. The American Association of Cost Engineers recognizes the need for such a contingency allowance in engineering cost estimates. Similarly, the Atomic Industrial Forum's Guidelines Study for nuclear decommissioning explicitly validates the inclusion of a contingency in decommissioning cost estimates. In the Guidelines Study, individual contingencies ranging from 10% to 75% were judged proper for various tasks, depending on their degree of difficulty. Those contingencies, when applied to the appropriate components of nuclear plant decommissioning costs, average upwards of 25% overall (PP&L St. 13, pp. 22-23). By comparison to the Guidelines Study, the contingency factors employed by Mr. LaGuardia, which average about 17%, are clearly conservative.

Furthermore, as previously indicated, regulatory commissions have generally approved contingencies of up to 25% in nuclear decommissioning cost estimates. The FERC adopted a 25% contingency for nuclear power plant decommissioning in the Middle South Energy/Grand Gulf Case (Docket ER82-616) (February 3, 1984). Additionally, numerous state commissions have adopted a 25% contingency for nuclear plant decommissioning, as evidenced by an AGA-EEI Depreciation Committee Survey, which showed that two-thirds of all survey respondents had previously approved such a contingency (PP&L St. 13, p. 24). This Commission has also approved decommissioning claims that included a 25% contingency, based on studies submitted by Mr. LaGuardia himself. See Pa. P.U.C. v. Pennsylvania Power Co., 85 PUR4th 323 (1987); Pa. P.U.C. v. Pennsylvania Power Co., 67 Pa. P.U.C. 91 (1983).[10/]

For the reasons set forth above, the Recommended Decision's proposed adjustment should be rejected.

10/ Although given no weight by the ALJ, opposing parties attempted to justify their proposed adjustment by reference to the Commission's rejection of a contingency in the Company's Unit 2 Case. That decision, however, is clearly distinguishable. At that time, the Company employed a judgment-based contingency factor, which it applied to a cost estimate derived from a "generic" decommissioning study. In contrast, for his site-specific SSES study, Mr. LaGuardia has analyzed each area having a high probability for problems, delays or additional costs, and has determined an appropriate contingency factor based on the actual experience of dismantling and decontaminating nuclear plants (PP&L St. 13, pp. 21-25). Moreover, in 1985, this issue had been addressed in relatively few jurisdictions, and the Commission relied upon a single decision from Massachusetts that purported to disallow a contingency. Since 1985, the weight of precedent from Federal and State regulatory agencies supports the use of a contingency factor.

E. <u>Nuclear Decommissioning Costs: Post-Shutdown Earnings</u>

PP&L calculated an annual decommissioning annuity sufficient to provide all needed decommissioning funds by the time SSES 1 and 2 are shut down at the end of their NRC licensed lives. OCA witness Catlin proposed an adjustment to reduce the Company's annual expense claim by treating post-shutdown earnings on trust assets as funds available to meet PP&L's decommissioning commitment.

As this controversy was played out during the course of the proceeding, it because clear that the central issue was whether Mr. Catlin's proposal to recognize post-shutdown earnings violated NRC rules. Mr. Catlin contended that it would not. That opinion, however, was rendered on the basis of a single telephone call to someone at the NRC. As explained in PP&L's Initial (pp. 143-144) and Reply (pp. 63-64) Briefs, it is evident that Mr. Catlin misunderstood the information he was provided. In contrast, Mr. LaGuardia, a nationally-recognized expert on nuclear decommissioning and related NRC regulations, testified that the NRC requires full funding of radiological decommissioning costs as of the time a nuclear unit is shut down (PP&L St. 13-R, p. 14).

The ALJ recommended adoption of the OCA's proposed adjustment because: "The money which remains unused during the decommissioning operation will be available to provide some return, contributing some money to the total pot" (R.D., p. 100). Of course, PP&L did not dispute that post-shutdown earnings will accrue in some amount. Rather, as previously discussed, the real issue is whether those earnings can be recognized without violating NRC guidelines. That issue was not addressed by the ALJ except for a single reference suggesting that the NRC's position on this issue was not "clear" (R.D., p. 100). In fact, the NRC's regulations and guidance documents could not be clearer.

NRC regulations governing nuclear power plant decommissioning funds (10 CFR § 50.75) require licensees to provide financial assurance of an amount sufficient to cover the estimated costs of decommissioning. A permitted method of providing financial assurance -- and the one chosen by PP&L -- is an external trust fund. With respect to that option, NRC regulations (10 CFR §50.75(e)(1)(ii)) mandate that periodic payments into the fund must be "sufficient to pay decommissioning costs <u>at the time termination of operation is expected</u>" (emphasis added). In short, the fund balance must equal the estimated decommissioning costs by the time the plant is shut down. Similarly, in the Statement of Considerations accompanying this regulation, the NRC stated that its objective was to assure that "<u>at the time of permanent end of operations</u> sufficient funds are available to decommission the facility in a manner which protects public health and safety" (emphasis added). 53 Fed. Reg. 24018, 24031 (June 27, 1988).

NRC guidance documents also drive this point home. In particular, Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors" (August 1990), contains the following provisions:

- Section C.1.1.1 states that licensees should have "a viable plan to accumulate funds in the certification amount, adjusted for inflation, <u>by the projected time of permanent cessation of operations</u>" (emphasis added).

- Section C.2.1.2 states that the "licensee should indicate that the method used [to establish financial assurance] provides, or will provide <u>at the projected cessation of operations</u>, an amount at least equal to the estimated or certified decommissioning cost for the facility" (emphasis added).

- Section C.2.2.5 states that the "[a]nnual deposits in an external sinking fund, including projected earnings, should attempt to approximate the total amount remaining to be accumulated, divided by the remaining years of the license, as determined by the initial and updated certification amount" (emphasis added).

The ALJ's confusion may have been caused by a nuance that Mr. Catlin stumbled over. As Mr. LaGuardia pointed out, the NRC has granted case-by-case waivers from the guidelines cited above, but only where a nuclear unit was retired prematurely (Tr. 2075-76). Obviously, PP&L could not qualify for such a waiver for SSES and, therefore, it must abide by the NRC's generally applicable requirements. The ALJ's recommendation is inconsistent with those requirements and should be rejected.

F. Fossil Decommissioning Costs

PP&L has proposed to establish an annuity, similar to the one used to fund nuclear decommissioning expense, to recover the cost of dismantling and demolishing its fossil-fired generating plants following their retirement from service.[11/] The Company's proposal would provide for the recovery of decommissioning costs over the operating lives of its fossil plants, so that customers actually receiving service from those plants would bear the attendant decommissioning expense. If the Company's proposal were not adopted, decommissioning costs would be deferred until after the plants are retired, at which point those costs would be recovered as a component of net negative salvage by means of a five-year amortization (PP&L Initial Brief, pp. 147-148).

11/ Like its nuclear decommissioning expense claim, the Company's fossil decommissioning cost estimate was based on site-specific studies prepared by Mr. LaGuardia (PP&L Initial Brief, p. 147).

The ALJ declined to recommend the adoption of the Company's proposal because he felt "constrained" to follow the Commission's decision in Pa. P.U.C. v. West Penn Power Co., Docket No. R-00942986 (December 29, 1994) (R.D., p. 106). However, the ALJ made it abundantly clear that PP&L's proposal has merit and the West Penn precedent should be reconsidered (R.D., pp. 106-107):

> PP&L acknowledges that net negative salvage will be a source of funding but stresses the customer impact and inter-generational equity issues. It states that the cost of decommissioning two of PP&L's large coal-fired plants is estimated to be $698 million. With net negative salvage, they would recover this at up to $140 million per year over five years. It would, under its proposal, recover this amount in annual installments of approximately $18 million over the remaining lives of the plants.
>
> I strongly sympathize with PP&L's proposal. There is an element of speculation built into this depreciation method of recovering decommissioning costs but, to my view, the PP&L approach improves upon the present practice. However, I am not so supportive of the PP&L approach as to disregard precedent.
>
> * * *
>
> Adherence to precedent will have a significant (and, I feel, adverse) impact on the "inter-generational" problem. I would rather see an orderly provision for decommissioning cost and again suggest that it is better to be approximately correct than precisely wrong. . . .
>
> I suggest that the Commission give this matter a hard look and entertain some thought of movement away from the Penn Sheraton precedent. (Emphasis added.)

The ALJ's fundamental endorsement of the Company's proposal should not be ignored. Annuitizing fossil decommissioning costs would not only promote inter-generational equity, as the ALJ concluded, but would assure that public health and safety risks are adequately addressed upon the retirement of fossil-fired generating plants. As explained in detail in PP&L's Initial (pp. 151-153) and Reply (pp. 71-72) Briefs, there are significant health and safety concerns associated with the hazardous materials and chemicals present in fossil-fired generating plants.[12/] The hazardous nature of the work required to dismantle those plants, and the risks to the public of not performing that work properly, clearly justify extending to fossil plant decommissioning the same "health and safety" exception to Penn Sheraton[13/] permitted for nuclear facilities. As such, Penn Sheraton is not a legal bar to the Company's claim.

For the reasons set forth above, the Company's proposal to pre-fund fossil decommissioning costs should be granted.

G. SSES 1 "Early Window" Costs

The Company's operating and maintenance expense claim in this proceeding included recovery, through a ten-year amortization, of "early window" costs associated with its Susquehanna plant.[14/] Following Commission precedent on this issue, particularly

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12/ As Mr. LaGuardia explained, virtually all older fossil-fueled plants are loaded with asbestos, lead-painted surfaces, acids and caustics. All work in abating and removing these materials is extremely hazardous. Federal and State regulations pertaining to the safety of workers exposed to such materials and dealing with the removal, transportation and disposal of those substances are rigorous, complex and costly (PP&L Initial Brief, pp. 152-152).

13/ Penn Sheraton Hotel Co. v. Pa. P.U.C., 198 Pa. Super. 618, 184 A.2d 324 (1962), is typically cited for the proposition that current recovery of prospective net negative salvage is not permitted. However, a notable exception has been recognized to permit the accrual of decommissioning costs for nuclear generating facilities because the significant health and safety risks associated with the closure of nuclear facilities justifies pre-funding such expenses. See Pa. P.U.C. v. West Penn Power Co., 54 Pa. P.U.C. 602 (1980).

14/ As explained in the Company's Initial Brief (p. 98), "early window" deferrals are those costs incurred between the date a new generating unit begins commercial operation and the date it is recognized in rates. These deferrals are accounting mechanisms that permit a utility to synchronize the costs and benefits of bringing a

Pa. P.U.C. v. Philadelphia Electric Co., 74 Pa. P.U.C. 1 (1990), the Recommended Decision approved the Company's claim for SSES 2 "early window" costs (R.D., p. 62). However, the ALJ rejected the Company's claim for SSES 1 costs because PP&L failed to claim those costs in the first base rate case following the Commission's Order authorizing their deferral. The disallowance of SSES 1 early window costs is inappropriate for several reasons and therefore should be rejected.

First, as explained in PP&L's Initial Brief (p. 99), the Commission authorized the Company to defer its claim for SSES 1 early window costs in Petition of Pennsylvania Power & Light Co., Docket No. P-820367, 1992 Pa. PUC LEXIS 75 (Order entered July 29, 1982). That Order states, inter alia:

> The issuance of this Order does not in any manner whatsoever determine the used and useful nature of Susquehanna Unit 1. Also, it is not a determination by the Commission that the costs involved were prudently incurred, that the energy savings were properly recorded or that the Company may recover deferred costs or retain deferred energy savings. Recovery of these costs will be subject to subsequent Commission audit and final disposition in a rate case proceeding. Id. at *17-18 (emphasis added).

The Commission's Order did not establish any time limit on PP&L's ability to claim and recover its SSES 1 early window deferrals, and certainly did not require PP&L to claim those costs in its next base rate proceeding. The Recommended Decision is clearly at odds with the Commission's Order authorizing the SSES 1 deferrals, and therefore should be rejected.

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new unit into operation, and ensure that the timing of a plant's commercial operation is not affected by ratemaking considerations.

Second, the recommended adjustment is inequitable. The argument that early window costs should be claimed in the first available base rate proceeding appears to have first arisen in 1990 in Pa. P.U.C. v. Philadelphia Electric Co., supra. The Commission's 1982 Order allowing PP&L to defer these costs contained no time limit on filing for cost recovery. PP&L's SSES 2 rate case was filed in 1984. It would be unfair and inappropriate to retroactively apply an argument first raised in 1990 to PP&L's decision not to claim these costs in 1985.

Third, as PP&L has previously explained (Initial Brief, pp. 100-101; Reply Brief, p. 38), it did not claim SSES 1 early window costs in its Unit 2 Case because it sought to minimize the requested rate increase and its impact on customers. PP&L submits that its efforts to reduce the requested rate increase in 1985 should be recognized as appropriate, and not penalized. In this regard, it is important to note that the Company's alleged "delay" in claiming its SSES 1 early window deferrals has not affected the amount of its claim because PP&L did not accrue any carrying charges during the deferral period (PP&L Initial Brief, p. 101, n. 36).

In sum, the denial of SSES Unit 1 early window costs is unsupported and would inequitably deprive the Company of amounts properly deferred pursuant to Commission Order. The recommended adjustment therefore should be rejected.

H. Additions To Taxable Income

The Recommended Decision adopted the OCA's proposed adjustment to reduce PP&L's tax expense claim for certain book/tax timing differences.[15/] As the Company explained in its Initial (pp. 192-193) and Reply (pp. 84-85) Briefs, this adjustment is inappropriate and should be rejected.

Book/tax timing adjustments can both increase and decrease tax expense for ratemaking purposes. However, the OCA improperly focussed on those items that increased tax expense and ignored those adjustments which decreased tax expense. To demonstrate this "cherry picking" approach, the Company provided an example in its rebuttal testimony of a book/tax timing difference in the treatment of power plant inventory which decreased tax expense (PP&L St. 3-R, p. 19). The ALJ accepted this concept by reducing the OCA adjustment to reflect the effect of this offset. The Company submits that the ALJ should have gone further and rejected the OCA adjustment in its entirety.

In the alternative, the adjustment adopted by the ALJ, at a minimum, must be recalculated to be consistent with his proposed treatment of uncollectible accounts expense. PP&L's claim for uncollectible accounts expense in this case was based on the estimated accrual to its uncollectible reserve. For tax purposes, however, uncollectible accounts are

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15/ The OCA initially proposed three adjustments: (1) ECR overrecoveries, (2) refueling outage costs, and (3) bad debt accruals (OCA St. 6, pp. 33-35). In surrebuttal testimony, the OCA's witness accepted a Company-proposed, offsetting adjustment relating to power plant inventories (OCA St. 6A, p. 14). The net adjustment of $4,089,000 on a Pennsylvania jurisdictional basis was adopted by the ALJ (R.D., p. 137 and Table III).

deducted when actually written off. This difference in the book and tax treatment of bad debts is one component of the OCA's adjustment to taxable income.

The OTS proposed to calculate uncollectible accounts expense based on the actual write-off and not on the accrual to the uncollectible reserve. The ALJ agreed and reduced PP&L's claim by $1,234,000 (R.D., pp. 69-70). However, this adjustment also eliminates the book/tax timing difference for bad debts and eliminates the OCA's corresponding tax adjustment. If the OTS adjustment for uncollectible accounts expense is adopted (and the Company has not excepted to that recommendation), then the bad debt portion of the OCA's adjustment to taxable income also must be eliminated. The OCA's witness specifically agreed with this analysis on cross-examination, stating that the bad debt portion of the book/tax timing adjustment would "go away" if the OTS' uncollectible accounts expense adjustment were adopted (Tr. 2043). The effect of this correction is to increase federal income tax expense by $610,000 and state income tax expense by $215,000.

I. <u>Gross Receipts Tax</u>

The ALJ adopted an OCA proposed gross receipts tax adjustment, thereby reducing PP&L's claim by $745,000 (R.D., pp. 130-132). Based on his concern that the Company's claim may result in "double counting," the ALJ concluded that the OCA's adjustment was appropriate "unless PP&L can show that I am wrong about this problem of double receipt of the tax amount" (R.D., p. 132). This adjustment is wholly inappropriate and should be rejected.

The ALJ's concern over "double recovery" was not raised by any party to the proceeding. The Company therefore had no notice that this was an issue and had no opportunity to respond. There is absolutely no record evidence to support a "double recovery" conclusion. Had the Company known that this was an issue, it would have presented expert testimony demonstrating there is no double recovery. In short, the Company should not be penalized for failing to anticipate arguments not made on the record.

The argument that was presented on the record was that the Company improperly calculated GRT on its total revenue request, and thereby failed to reflect the fact that a portion of its requested revenue increase will not actually be collected (due to bad debts). As fully explained in the Company's Initial Brief (pp. 194-196), this argument is completely without merit, and if adopted, would simply assure that the Company does not earn its allowed rate of return.

The OCA argument that the Company is fully compensated for the effect of uncollectible accounts through an expense allowance is equally unavailing. First, the issue here is revenues, not expenses. All of the revenues requested are required to permit the Company to earn its requested return. The fact that the Company will not actually collect all of this revenue and will not actually earn its requested return provides no basis for further reducing the Company's rates (and its return) by disallowing GRT on revenues which will not be collected.

Second, the OCA is factually wrong. In order to be conservative and to keep the total amount of its requested increase reasonable, the Company did not claim any additional uncollectible accounts expense associated with the revenue increase requested in this proceeding (PP&L Initial Brief, pp. 195-196). This reduced the Company's claim by $1.6 million -- more than twice the OCA's proposed GRT adjustment. Thus, the OCA's contention that the Company is fully compensated through uncollectible accounts expense, even if theoretically correct, is factually in error in this case and should be rejected.

J. Treatment Of Costs Associated With Terminating Off-System Sales Agreements

The Recommended Decision rejects PP&L's request to include in its Energy Cost Rate ("ECR") the cost of capacity that will become available to the Company over the next five years with the phased termination of its long-term sales agreement with JCP&L beginning on January 1, 1996 (R.D., pp. 274-275).[16] The ALJ's recommendation appears to have been motivated primarily by his concern that PP&L's proposal is "too innovative and too automatic" (R.D., p. 274). PP&L respectfully submits that these concerns are without merit and are clearly outweighed by the substantial benefits afforded by the Company's proposal.

Faced with the phased termination of the JCP&L agreement, PP&L had three options for dealing with the returning capacity: (1) secure another buyer in the bulk power market; (2) file annual or periodic retail base rate cases; or (3) absorb the related costs of such capacity. In the Company's view, none of these alternatives were satisfactory or in the public interest. PP&L therefore advanced an innovative proposal to reflect the cost of each "slice" of returning capacity in its ECR and, at the same time, to credit all revenues from off-system capacity-related sales.

16/ As explained in its Initial Brief (p. 292), the Company's ECR proposal would also apply to sales agreements with AE and BG&E which are scheduled to expire in the years 2000 and 2001, respectively.

As explained in PP&L's Initial (pp. 291-294) and Reply (pp. 134-135) Briefs, the Company's proposal has several substantial benefits. First, PP&L is likely to continue to make off-system capacity-related sales that would result in significant revenues. Under traditional ratemaking, the Company would retain all revenues from such sales received between base rate cases. Under PP&L's proposal, these revenues would be credited immediately to customers through the ECR. Second, PP&L's proposal would reduce costs and regulatory burdens for all parties and the Commission by reducing or eliminating the need for annual or near-annual base rate cases.

The ALJ's concern that the Company's proposal lacks sufficient checks and balances is unfounded and is perhaps a result of the proposal's novel approach. The Commission and any party concerned about potential overearnings can monitor PP&L's quarterly reports to the Commission and can institute an investigation if they believe sufficient cause exists. While the ALJ notes that this can be a "cumbersome and slow process" (R.D., p. 275), PP&L believes that the substantial benefits of its proposal would outweigh any monitoring costs that may be incurred and certainly would be less burdensome than annual base rate filings.

In sum, the Company's proposal will produce significant benefits for customers and is in the public interest. Although PP&L recognizes that its proposal is a departure from traditional practice, the Company believes that this fact should not be allowed to obscure the benefits of this innovative proposal.

K. Rate Case Expense

The Recommended Decision adopts the OTS' proposal to normalize PP&L's claim for rate case expense over a four-year period (R.D., p. 72). The OTS' proposal was based on a review of PP&L base rate cases over a twenty-year period, including the abnormally long ten-year period since the filing of its last base rate proceeding. Despite the unusual circumstances which permitted PP&L to delay the filing of this case, the ALJ refused to exclude this ten-year filing period from his analysis and concluded that the OTS' proposed four-year normalization period was appropriate.

A four-year normalization period should be rejected. As explained in PP&L's Initial (pp. 111-113) and Reply (pp. 49-50) Briefs, the record evidence demonstrates that the abnormally long stay-out period preceding this case is not likely to recur. If this unusual period is disregarded, PP&L's average rate case filing period is 2.3 years (PP&L St. 3-R, pp. 5-6). The Company's two-year proposal, therefore, is clearly reasonable. Moreover, given the level of revenue increase proposed by the ALJ and his proposed denial of the Company's proposal for ECR recovery of returning capacity, it is simply not credible to expect that the Company will stay out for four years before filing another base rate case. A four-year normalization would provide the Company with no reasonable opportunity to recover its reasonable rate case expense and should be rejected.[17/]

17/ Moreover, while each company's circumstances are unique, PP&L would note that a four-year normalization is out of line with other recent Commission decisions. See, e.g., Pa. P.U.C. v. West Penn Power Co., Docket No. R-00942986, 1994 Pa. PUC LEXIS 144 (Order entered December 29, 1994)(24 months); Pa. P.U.C. v. UGI Utilities, Inc. (Elec. Div.), Docket No. R-00932862, 1994 Pa. PUC LEXIS 1137 (Order entered July 27, 1994)(16 months); Pa. P.U.C. v. Pennsylvania-American Water Co., Docket No. R-00932670, 1994 Pa. PUC LEXIS 120 (Order entered July 16, 1994)(12 months); Pa. P.U.C. v. Roaring Creek Water Co., Docket No.

L. Environmental Remediation Costs

The ALJ recommends that PP&L's claim for environmental remediation expense be reduced by $326,000 to reflect the maximum level of expense the Company is obligated to incur pursuant to an April 27, 1995 agreement with the Pennsylvania Department of Environmental Resources ("DER"). This recommendation lacks merit and should be rejected.

As the Company explained in its Initial (pp. 105-107) and Reply (p. 47) Briefs, PP&L's recent agreement with DER requires the Company to investigate and, if necessary, to clean up 134 potentially contaminated sites. Given the large number of sites and the broad scope of work encompassed by the agreement, PP&L submits that its claim of $5.4 million is a more accurate projection of the costs it likely will incur on an ongoing basis than the reduced amount proposed by the Recommended Decision. The ALJ's proposed adjustment therefore should be rejected.

M. Cost Of Service Study: Allocation Of QF Output Payments

The Recommended Decision appears to adopt both PPLICA's proposal to adjust the demand/energy basis for allocation of QF output payments in the roll-in of the ECR (R.D., p. 208), and PP&L's subsequent proposal to exclude from the ECR revenue adjustment credit (line 4 of pages 83-84 of Ex. JMK-2) the effect of the QF output payment demand/energy allocation (R.D., p. 193). As explained below, however, the parties agreed

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R-00932665, 1994 Pa. PUC LEXIS 41 (Order entered February 3, 1994)(12 months).

during the course of these proceedings that PP&L's adjustment was appropriate. The Recommended Decision therefore should be clarified to reflect the parties' agreement.

As explained in its Initial Brief (p. 246-247), PPLICA initially proposed to adjust the demand/energy basis for allocation of the QF output payments in the roll-in of the ECR. The Company opposed PPLICA's proposal, but agreed that some adjustment was appropriate. PP&L therefore revised its final accounting exhibit to reflect exclusion of the QF output payment demand/energy allocation from the ECR revenue adjustment credit. The record evidence shows that PP&L's proposed adjustment would produce a result very similar to that produced by PPLICA witness Baron's adjustment (PP&L St. 7-R, p. 19). Mr. Baron did not oppose the Company's alternative proposal (PPLICA St. 7-S, p. 2).

In light of the foregoing, the Recommended Decision should be clarified to reflect the parties' acceptance of PP&L's proposed adjustment. The Company's unopposed proposal is reasonable and should be adopted.

N. <u>Cost Of Service Study: Allocation Of The EDI/IDI Credits</u>

The Recommended Decision adopts PPLICA's proposal to assign the costs of the EDI/IDI credits to all customers, rather than those customer classes that directly receive rate discounts from those programs (R.D., pp. 209-210). The ALJ's recommendation rests largely on his conclusion that all customers benefit from the EDI/IDI programs.

The proposed adjustment should be rejected. While all customers, both participants and non-participants, may benefit from these programs, those benefits are not shared equally. Participants receive much greater benefits, and the cost of these programs should be allocated accordingly.[18] Costs should be allocated based on those factors which cause a cost to be incurred. The "cause" of the cost here is the rate discount to industrial customers receiving the EDI and IDI discounts. The "cost" of these discounts therefore should be allocated to the industrial customer classes which receive those discounts.

Finally, the recommended adjustment is inconsistent with the Commission's treatment of similar costs and lost revenues produced by Demand-Side Management (DSM) programs (PP&L St. 8-R, p. 38). The Commission's current DSM Order (Docket No. I-900005) requires recovery of costs and lost revenues from the classes receiving direct benefits from the programs (Id.). The ALJ's recommendation, therefore, is inappropriate and should be rejected.

O. Rate Design: Residential Customer Charge

The Company proposed a Rate RS customer charge of $7.20/month, reflecting an increase of 50% over the existing customer charge of $4.80/month. The ALJ has recommended a maximum increase of 35% and further proposed that the customer charge increase "be scaled back with lesser increases." (R.D., p. 230). The Company does not oppose a 35% increase in the Rate RS customer charge, as it represents a reasonable accommodation of the competing positions advanced by the parties. The proposed scale back, however, should be rejected for two reasons.

18/ As explained in the Company's Initial Brief (p. 286, n. 89), PP&L Ex. OGK-4 demonstrates that absent the sample of 20 customers whose load would not have been retained without EDI/IDI, the class rate of return for the system would decline from 7.31% to -17.10%, which is far less than the difference for LP-4 (8.96% to -51.56%) and LP-5 (5.34 to -109.18%).

First, no party to this proceeding proposed to scale back the Company's customer charge to reflect the overall rate increase. There is therefore no record evidence to support this adjustment. If the issue had properly been raised during these proceedings, PP&L would have offered expert testimony demonstrating the inappropriateness of this proposal. It would be unfair to adopt this adjustment without providing the parties an opportunity to address its merits on the record. Second, to the best of the Company's knowledge, the concept of a "scale back" applies to the overall increase to a rate class and not to the design of individual rates. The Recommended Decision's application of "scale back" to rate design issues is unprecedented and should be rejected.

PP&L's proposed customer charge was fully supported by its cost of service study, which showed total residential customer costs of $17.51 per customer per month. Billing and metering costs alone were $10.18 per customer per month (PP&L St. 8-R, p. 6). As explained in its Initial Brief (pp. 251-252), PP&L evaluated higher and lower customer charges, but concluded that its proposed charge was appropriate and would not unduly impact low or high users of energy.

IV. CONCLUSION

For the foregoing reasons, the Commission should grant the Company's Exceptions and adopt the Recommended Decision with the modifications described herein.

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DATED: August 14, 1995

APPENDIX A

In the seat of power

On a hot day, this "pool" is crackling with tension.

By Andrew Maykuth
INQUIRER STAFF WRITER

In the basement of an unmarked, tan brick building in the Valley Forge Corporate Center on Wednesday, Joe Florek nervously watched lights blink on a two-story map of the region's power grid.

The temperature was soaring. So was demand for electricity.

At 2:55 p.m., Florek picked up a telephone and broadcast an urgent message to the control rooms of 11 power companies from New Jersey to Washington:

"We are now at maximum emergency generation," said Florek, a dispatcher for the PJM Interconnection Association, the power pool that controls the flow of electricity to 22 million people in five mid-Atlantic states.

The message to utilities: Give us everything you've got; the next step is to start shutting off customers.

In downtown Philadelphia, at the Peco Energy Co. headquarters, Florek's voice crackled over a loudspeaker. An order went out to Peco's Conowingo Hydroelectric Station on the Susquehanna River to let more water flow through its generators.

In New Jersey, Public Service Electric & Gas Co. fired up the last of its combustion turbines, the jet-powered generators that act as the utility's last emergency power reserve.

At PJM headquarters in Lower Providence Township, dispatcher Bill Fox was on the telephone to the Potomac Electric Power Co. in Washington, which told him that two turbines were not yet fired up.

"How many megawatts are they?" he asked brusquely. "Bring them on."

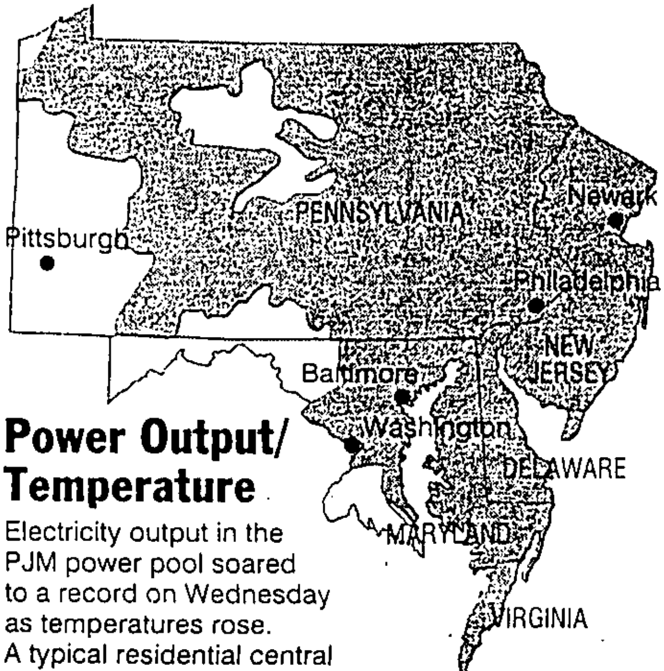
The region's electrical utilities were pushing their limits on Wednesday afternoon as millions of air conditioners strained under the sweltering heat. By early afternoon, the 11 utilities in the power pool had already surpassed their forecast output for the day.

They had to sweat out the last hours before reaching the moment of truth, 5 p.m., when electrical demand typically peaks during a summer day.

"We don't know how much demand is out

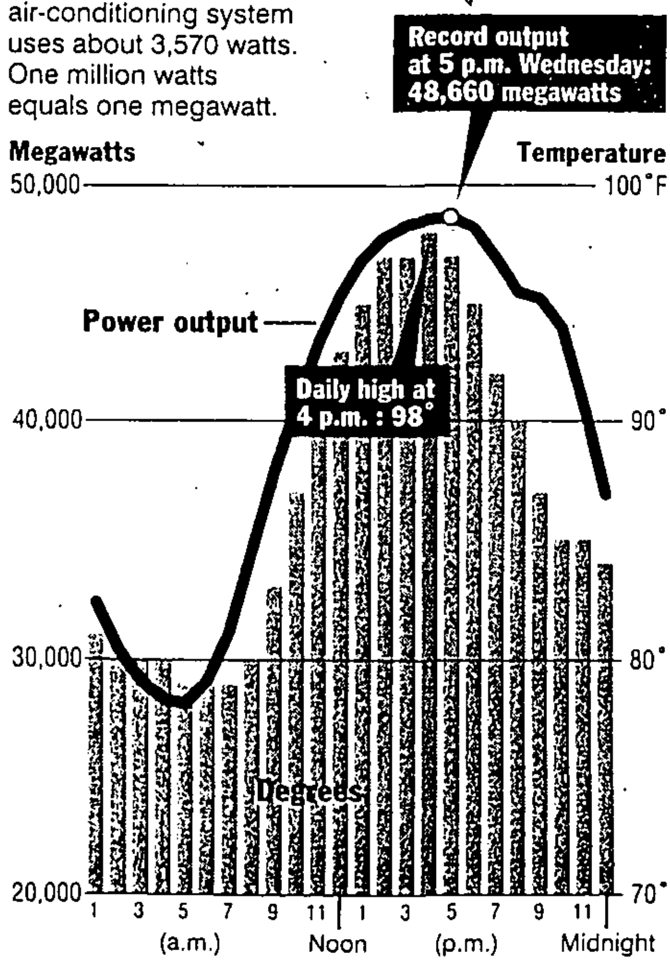
See **POWER** on C2

PJM Service Area



Power Output/ Temperature

Electricity output in the PJM power pool soared to a record on Wednesday as temperatures rose. A typical residential central air-conditioning system uses about 3,570 watts. One million watts equals one megawatt.



SOURCES: PJM Interconnector Association, Peco Energy Co., National Weather Service

The Philadelphia Inquirer

The power is in their hands at PJM

POWER from C1

there," Jeff Williams, a PJM strategist, said at 3 p.m. "Is the whole load on now? There's a bunch of stuff out there that could kick on if the temperature goes up one degree more."

In the end, records fell. At 5 p.m., PJM utilities sold more power — 48,660 megawatts — than at any other time. But with the help of massive inflows of electricity from the Midwest and New York, the region's power system stayed intact, though a few nerves were frayed.

"It's a new high load; you're not sure what will happen," said Bruce M. Balmat, an engineer who manages PJM's performance department.

To most consumers, it was as if nothing happened. No transmission lines melted down. No brownouts occurred. There were no major failures among the 540 generating units that produced power in the crunch.

No customers were shut off on Wednesday, though a few large customers were curtailed yesterday as the system once again flirted with record output.

Most customers will not realize how much energy was consumed this week until their electric bills arrive in the mail later in the month, reflecting tens of millions of dollars spent mostly to cool hot air.

At 5 a.m. Wednesday, while the temperature in Philadelphia was 79 degrees, the PJM network was experiencing its quietest hour of the day.

As the sky grew light, the 11 utilities were generating 28,180 megawatts of power for their slumbering customers — enough power to keep 22 million window air-conditioners running.

Over the next 12 hours, the temperature would rise to 98 degrees in Philadelphia, and the PJM utilities would nearly double their output, adding on 20,000 megawatts, the equivalent of bringing 20 giant nuclear generating units on-line in less than half a day.

By 10 a.m., much of the system's largest power plants were operating at full tilt. PJM also was buying 5,300 megawatts from neighboring systems, primarily Allegheny Power Systems to the west and the New York Power Pool to the north.

At 11 a.m., Peco began opening the valves at its Muddy Run hydroelectric plant, a reservoir on the bluffs along the Susquehanna that it had filled overnight with water pumped from the river. Three hours later, Muddy Run was generating its maximum output, 860 megawatts.

By midday, Peco was turning on most of the 33 combustion turbines throughout its service territory. Eight turbines at its Croydon Station in Bristol went on between noon and 2 p.m., supplying about 304 megawatts. At its old Richmond plant, two turbines went on at noon and would remain on until 8 p.m., when demand fell off.

A good portion of the bill that electric customers pay each month is to finance the cost of generators to meet peak demand. PJM requires its members to provide 20 percent capacity above their forecast peak demand.

PJM is the world's fourth-largest power pool, dwarfed only by the national systems in France and England and the Tokyo Electric system. It was formed in 1927 when Peco, PSE&G and Pennsylvania Power & Light Co. formed an interconnection to sell each other power.

The Pennsylvania-New Jersey-Maryland Interconnection — later shortened to PJM — took on its modern form in 1956 with the addition of Baltimore Gas & Electric Co.

The nation's power pools gained more authority after blackouts in 1965 and 1967 darkened New York and New England because utilities had failed to correct an imbalance in the transmission system, which caused a cascade of failures.

PJM procedures now call for systematic "load-shedding" if consumption exceeds the power pool's ability to generate power or its ability to buy it from other areas, such as the Midwest, where the shrinking steel industry has left utilities with excess capacity.

The procedure calls for utilities to first call for conservation and then to curtail service to large customers who have agreed to have their power interrupted in exchange for a lower rate. By cutting interruptible customers, the system can reduce demand by about 1,500 megawatts, Balmat said.

The utilities also can reduce voltage by up to 5 percent, which would reduce demand by about 700 megawatts.

If customer demand still overloads circuits, utilities can institute "rolling blackouts," which are temporary interruptions of customers. PJM has done systemwide "load sheds" only twice: in 1970 and in January 1994, when severe cold crippled the generation system.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
v.	:	DOCKET NO. R-00943271
PENNSYLVANIA POWER & LIGHT COMPANY	:	

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon the participants listed below, in accordance with the requirements of Section 1.54 (relating to service by a participant).

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