PPLICA Statement No. 1

8704TES
HB6

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-00049255
	)	
PPL Electric Utilities Corporation	)	

Includes Exhibits SJB1 to SJB4

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

PP&L INDUSTRIAL CUSTOMER ALLIANCE ("PPLICA")

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

June 2004

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm

provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than twenty-nine years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, and Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

Q. Would you please discuss your experience in electric utility restructuring proceedings?

A. I have been extensively involved in electric utility restructuring since 1995. This involvement includes participation in eight proceedings in Pennsylvania, seven of which involved detailed implementation analyses associated with restructuring. In these cases, I addressed stranded costs, regulatory policy associated with retail competition and restructuring implementation, and rate unbundling. The utilities included PECO Energy, Pennsylvania Power & Light Company, West Penn Power Company, Metropolitan Edison Company, Pennsylvania Electric Company and Duquesne Light Company. I also provided

testimony in the recent proceeding addressing Duquesne Light Company's Provider of Last Resort service proposal.

I have also been involved in restructuring proceedings in the State of Maryland associated with Baltimore Gas & Electric Company and Potomac Edison Company. In addition, I participated in a generic proceeding before the Maryland Public Service Commission on electric utility restructuring and have testified before the Maryland Legislature on this issue.

In 1999, I was involved in restructuring proceedings in West Virginia associated with the Appalachian Power subsidiary of AEP and Monongahela Power Company, a subsidiary of Allegheny Power Company. I also participated in restructuring proceedings in Connecticut involving United Illuminating Company and Connecticut Light and Power Company. In 2000, I participated in electric restructuring proceedings in Ohio involving First Energy Corporation and Cinergy.

In Louisiana, I have been involved in the Entergy Gulf States, Inc. ("EGSI") stranded cost proceeding and in the Commission's generic proceeding on retail competition. I have addressed issues on stranded cost quantification, standard offer tariffs, load profiling and other issues. I also have been involved in the proceeding to separate the Texas and Louisiana jurisdiction assets of EGSI as a result of legislation authorizing retail access in Texas.

To date, I have presented testimony in 13 electric restructuring proceedings.

Q. Have your previously presented testimony in PPL rate proceedings?

A. Yes. Since 1984, I have participated in five PPL proceedings before the Pennsylvania PUC.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the PP&L Industrial Customer Alliance ("PPLICA"), a group of large industrial customers of PPL Electric Utilities Corporation ("PPL") who take service primarily on PPL Rate Schedules LP-4, LP-5, LP-6, IS-P and IS-T. I will refer to customers on these rate schedules generally as Large Commercial and Industrial or "Large C&I" customers.

Q. Would you please briefly describe the members of PPLICA who are participating in this rate proceeding?

A. There are nineteen PPLICA members who are participating in this rate proceeding and on whose behalf I am presenting testimony. These companies consume in excess of 2.2 million mWhs annually on the PPL system. PPLICA member companies are major employers in the state of Pennsylvania and contribute in a substantial manner to the overall economy of the state. This contribution includes not only direct benefits in the form of jobs to Pennsylvanians, but also includes the payment of corporate state income taxes, charitable and community development contributions and other activities which contribute to the overall well being of the citizens of the state.

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

A. I have been asked by PPLICA to review PPL's rate filing in this proceeding, with emphasis on cost allocation, rate design, tariff issues and, in particular, the Company's proposal to recover transmission charges through a transmission service charge ("TSC").

The first issue that I will address in my testimony concerns the design of the Company's proposed transmission cost recovery mechanism in the form of a TSC as discussed in PPL's testimony in this case. The Company is proposing to pass-through its transmission charges, pursuant to the PJM Open Access Transmission Tariff ("OATT"), through a formula rate that would be updated annually. PPLICA has not reviewed the underlying cost data to confirm with certainty that the formula and charges accurately reflect the transmission and ancillary service costs that PPL will incur from PJM; however, PPLICA does not oppose the general concept of an automatic formula-based transmission recovery mechanism as long as that formula reflects the correct categories of PJM transmission and ancillary service costs. PPLICA does have significant concerns regarding the design of the TSC charge and its inconsistency with the underlying cost incurrence basis for those charges. I will discuss these concerns and recommend an alternative design for the TSC that will more properly align the retail transmission charges (pursuant to a TSC) with the underlying costs that PPL incurs from PJM.

The second issue that I will address concerns the Company's proposed allocation of its distribution revenue requirement increase in this proceeding. PPL is proposing a $162 million increase in distribution revenues in this case. This represents a 33% increase in

distribution revenues. PPLICA has substantial concerns regarding the allocation of the proposed increase among PPL's rate schedules.

As discussed in the testimony of PPL witnesses Joseph Kleha and Oliver Kasper, there are substantial disparities between the costs of providing distribution service to the Company's various rate schedules and the amount of distribution revenues currently being collected from these rate schedules. Because the Company has not adjusted its distribution rates since the rate unbundling that became effective in January 1999 (as well as the fact that the current underlying unbundled distribution rates were established based on allocated costs from 1995), there are substantial subsidies embedded in current distribution rates. PPL has recognized this problem and has attempted, though in an insufficient manner, to mitigate this disparity in its allocation of the requested revenue requirement increase to rate schedules. I will discuss this issue and propose an alternative allocation of the Company's authorized revenue requirement increase that will move class rates of return much closer to the system average return and, within a reasonable time, get all customers to the system average rate of return.

The next issue that I will discuss concerns the Company's proposed distribution system improvement charge ("DSIC") that would permit the Company to automatically recover costs associated with certain new distribution system investments. As I will discuss, PPLICA opposes the Company's request for a DSIC in this proceeding. The DSIC provides the Company an opportunity to increase its rates for a single issue (changes in distribution investment), while ignoring other costs changes that may potentially offset these increases

and would otherwise be considered in a base rate proceeding. Under the Pennsylvania Public Utility Code, the Company is entitled to file rate requests when it can justify a change in its overall revenue requirement. This is the appropriate mechanism for the Company to seek an increase in distribution charges to its customers, not through an automatic adjustment clause.

The next issue that I will address concerns the Company's request to extend the sustainable energy fund ("SEF") rider. Pursuant to the "Joint Petition for Full Settlement of PPL, Inc. Restructuring Plan and Related Court Proceedings," Docket No. R-00973954 (dated August 12, 1998), the Company agreed to establish an SEF that would be fully funded by the Company's shareholders. This SEF funding was to terminate on December 31, 2004, unless PPL did not file a distribution base rate proceeding to establish new distribution rates. The Company is now proposing in this case to extend the SEF to December 31, 2009. Significantly, the Company is now proposing to recover the costs of this SEF from its ratepayers, and terminate the funding by shareholders. As I will discuss, there is no reason to adopt the Company's proposal for the SEF rider, to be paid by ratepayers. This SEF was intended to be a self-sustaining fund to provide research grants and loans to promote the development and use of renewable energy and clean energy technologies, energy conservation and efficiency which promote clean energy. The SEF should not be funded by PPL's ratepayers, but rather should be an independent organization that is either self-sustained or would rely on voluntary contributions by individuals and business in Pennsylvania or, in the alternative, government grants. However, the SEF is not a part of

the Company's cost of providing distribution and transmission service and should not be included in the Company's overall revenue requirement.

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- **PPL's proposed Transmission Service Charge tariff rider should be modified to properly reflect the cost basis underlying the charges incurred by PPL pursuant to the PJM OATT. Based on the 2004 estimated transmission revenue requirements, 73% of the costs are charged to PPL on a kW demand basis, while only 27% are charged on a kWh energy basis. Despite these cost classifications, PPL is proposing to recover 100% of its transmission costs from ratepayers on a kWh sales basis, ignoring cost of service differences.**

  PPLICA proposes a modified TSC that reasonably reflects the cost basis underlying PPL's PJM transmission charges by separately computing demand and energy TSC components (TSC_D and TSC_E). PPLICA also recommends that the reconciliation provision of PPL's proposed TSC be eliminated. The PPLICA recommended TSC would incorporate annual updates and interim updates in the event of a FERC approved OATT change.

- **PPL's proposed allocation of its requested $162 million distribution revenue requirement increase does not sufficiently mitigate the substantial subsidies received and paid by various PPL rate schedules. For example, PPL's current residential distribution rates are subsidized by other rate schedules in the amount of $51.3 million per year. Under proposed PPL rates, this residential class subsidy would actually increase to $77.8 million per year. PPLICA recommends that any Commission authorized distribution revenue increase be allocated in such a manner as to reduce the dollar subsidies contained in present rates by 50% at proposed rates. In addition, PPLICA recommends pre-approved rate adjustments in the second and third years following the implementation of any authorized new rates in this case to reduce subsidies by additional amounts of 25% in each year.**

- **PPL's proposed Distribution System Improvement Charge ("DSIC") should be rejected because it would result in a single-issue rate change and has not been shown to be needed by the Company. The proposed DSIC also inappropriately incorporates a kWh sales recovery factor that essentially allocates the incremental distribution investment to rate schedules on the basis of relative kWh sales, rather than the cost of service allocation factors used by the Company to assign cost responsibility for distribution related facilities. This is in contrast to the Company's desire to collect more distribution revenues**

through non-variable, monthly customer charges due to the fixed nature of most distribution-related costs and could result in PPL over-earning in high sales years.

- **PPLICA opposes the inclusion of SEF funding as an element of distribution cost of service. PPLICA does not oppose the SEF, only the proposal by PPL to shift the funding burden from PPL shareholders to PPL captive distribution ratepayers. The SEF is not a cost of providing distribution service to PPL's ratepayers and should not be included in its cost of service based charges. The appropriate funding source for the SEF is either private or governmental grants, not from the electric consumers of PPL.**

II. PPL's PROPOSED TRANSMISSION SERVICE CHARGE

Q. Have you reviewed the Company's proposal to implement a TSC in this proceeding?

A. Yes. The Company is proposing a transmission service charge that would be applicable to all Basic Utility Supply Service ("BUSS") or Provider of Last Resort ("POLR") customers purchasing supply service from PPL, designed to recover the charges incurred by PPL pursuant to the PJM Open Access Transmission Tariff ("OATT"). This TSC would recover the revenue requirements associated with PPL's transmission obligation ("TO"), as well as ancillary service and other PJM charges. It would only be applicable to POLR customers and would be updated annually, with reconciliation to actual costs. According to PPL, the reconciliation is designed to reflect the difference in actual transmission revenues collected from customers and the final actual PJM costs charged to PPL.

Q. Do you have an objection to the general concept of a TSC to recover PJM charges that are being passed-through to POLR customers by PPL?

A. No. PPLICA does not object to the concept of a TSC to recover PJM OATT charges. However, as I will discuss next, the Company's proposed TSC is not just and reasonable with regard to the specific recovery of costs from rate schedules, relative to the cost basis on which PPL is charged these transmission costs by PJM. As a result, the PPL proposal exacerbates an already inequitable allocation of PPL's distribution revenue requirement (discussed infra) to the severe detriment of PPL's Large C&I customers.

Q. How does the TSC recover transmission revenue requirements from PPL rate schedules and retail customers?

A. The Company is proposing to recover all PJM OATT revenue requirements through a uniform kWh sales charge. There is no recognition in the TSC mechanism to distinguish the recovery of costs that are incurred by PPL on a kW demand basis, from those incurred on a kWh energy basis. Nor is there any recognition in the TSC to reflect voltage differentials and the corresponding losses associated with serving each of the Company's rate schedules. Despite the fact that PJM provides bills to PPL for transmission service and ancillary services on both a kW demand and a kWh energy basis (for various components of the overall PPL transmission revenue requirement obligation), PPL has decided to ignore this cost differential (demand versus energy) in its TSC.

Q. Do you believe that the Company's design of the TSC is reasonable, in light of the Company's proposal to establish a single kWh energy charge for all transmission revenue requirements applied to customer sales, regardless of voltage level, load factor or other customer load characteristic differences among rate schedules?

A. No. The Company's proposed design of the TSC is not reasonable and results in an unjust allocation of PPL transmission revenue requirements among its schedules. In addition, the Company's TSC proposal will result in different transmission charges for its retail customers, depending on whether such a customer is a POLR customer or purchases generation supply from an Electric Generation Supplier ("EGS"). As I will discuss, PPL's proposed TSC recovery mechanism, which recovers both demand and energy related costs through a uniform kWh sales rate creates a disparity in the charges that customers would

pay for POLR transmission service versus the allocated costs to an EGS for the same customer pursuant to PJM cost allocation methods.

This lack of consistency between the PPL POLR transmission rate and the costs assigned to an EGS for the same customer for the same transmission service is inappropriate and could lead to confused and uneconomic decision-making on the part of the Company's customers. In addition, if a customer is paying a subsidy under the TSC and subsequently moves to an EGS, PPL would experience a revenue shortfall, all else being equal, since costs would decrease less than revenues upon losing the customer. Irrespective of this consistency problem, the Company's proposed cost recovery mechanism completely ignores cost-based differences in providing transmission service to the Company's retail rate schedules.

As I will discuss, a relatively straightforward decomposition of the PPL transmission revenue requirements into demand and energy components can easily be implemented in a TSC mechanism. Transmission and ancillary service costs should be allocated to PPL's rate schedules consistent with the methodology that PJM uses to bill PPL for the services and, for larger customers, the retail transmission rates should be designed consistent with the PJM charges by including demand and energy components. Such an alternative TSC, which considers the cost basis associated with each of the charges incurred by PPL from PJM, would produce a just and reasonable recovery mechanism for the Company's costs.

Q. Would you please discuss the components of the Company's overall transmission revenue requirement that PPL is requesting to recover in its TSC?

A. Baron Exhibit ___(SJB-2) shows a summary of the cost components underlying the $199.4 million PJM OATT revenue requirement that the Company projects for the 12-months ended December 31, 2004. This is the basis for the Company's requested initial TSC of $0.00564 per kWh in this proceeding. As I indicted, the Company is proposing to recover a uniform $0.00564 per kWh from each of its POLR sales kWh, beginning January 1, 2005.[1]

As can be seen in the summary of the transmission charges associated with the Company's TSC in Exhibit SJB-2, each of the PJM charges is billed on either a kW demand or a kWh energy basis from PJM to PPL. In particular, the network transmission charges of $125 million are billed to PPL on the basis of an allocation of PPL's zonal transmission revenue requirement between PPL (for serving POLR customers) and other customers (UGI, FERC wholesale load and alternate suppliers) on the basis of contributions to the annual PPL zonal coincident peak demand. In addition, as also shown in Exhibit SJB-2, two ancillary services that are purchased by PPL are also assigned and charged by PJM on a kW demand basis. These two services are "reactive supply and voltage control" and "black start" services. Based on the Company's 2004 estimated transmission charges, $146 million of the total $199 million in costs is charged to PPL on a kW demand basis. This represents 73% of the total revenue requirement. Only $53 million or 27% of the transmission revenue requirement is being charged to PPL on the basis of kWh energy.

[1] As shown in Exhibit D-3 of PPL witness Kasper, the Company does not propose to recover this TSC charge from ISA and PRS kWh sales. For these customers, the Company is either maintaining transmission rate revenues at current levels or including the actual incremental costs in the Real Time Price rates (for PRS).

Despite this cost basis underlying the transmission revenue requirement, PPL is proposing to recover 100% of its transmission revenue requirement on a kWh sales basis. The Company is not even recognizing voltage loss differentials among rate schedules in the recovery of its transmission revenue requirements. Thus, for example, residential customers who take service at secondary voltage are charged the same rate per kWh as customers on Rate Schedule LP-5 who take service at transmission voltage. Since PPL is charged for transmission services by PJM on the basis of billing determinants (kW demand and kWh energy) at the transmission voltage level, the actual cost to serve retail customers varies depending on the voltage at which such retail customers actually take transmission service on the PPL system. Residential customers who take service at secondary voltage have higher costs, everything else being equal, than customers who take service on Rate Schedules LP-5 or LP-6 at transmission service voltage. The Company has completely ignored this voltage related cost differential, as well as the demand/energy cost basis of the charges in the first place.

Q. Do the Company's current transmission charges for retail customers better reflect the manner in which PPL incurs transmission costs?

A. Yes, but not with the level of precision that will result from PPLICA's proposal. For the current costs, rather than assessing all customers a unitized transmission charge, the Company charges a different transmission rate for each rate schedule, presumably to reflect the allocation of transmission costs to the rate schedules, which is based primarily (if not entirely), on a kW demand basis. The retail transmission rate for each rate schedule is then stated on a cents per kWh basis. The two improvements that I propose in this case are to

allocate the transmission and ancillary service costs that are the components of the TSC based on the manner in which PPL incurs the charges from PJM and to differentiate demand costs and energy costs by incorporating two rate elements within the TSC, rather than combining all costs to produce a single cents per kWh rate.

Q. What rationale has the Company provided for ignoring the cost basis underlying its transmission revenue requirement in the design of the TSC?

A. The Company does not really explain why it is proposing to recover all transmission revenue requirements on a kWh basis except that it appears to be simpler to implement. The Company has apparently decided that it is more appropriate to design a TSC that is easy to implement than one that is designed to properly recover costs from its ratepayers. There is no substantive reason why the TSC cannot be designed to properly reflect the incurrence of costs by PPL for transmission service from PJM.

Q. Does the Company agree that its proposed TSC transmission cost recovery mechanism produces a different allocation of transmission costs than it currently collects from its customers through unbundled rates?

A. Yes. In the testimony of PPL witness Douglas Krall (PPL Statement No. 4 at page 33), the Company admits that its proposed TSC changes the allocation of transmission costs among its customers. However, the Company then argues on page 34 of Mr. Krall's testimony that the uniform kWh charge pursuant to the TSC is "generally consistent with how PJM bills all load servers – electric distribution companies and electric generation suppliers ...." (Krall testimony, page 34 at lines2-3).

In response to an Office of Trial Staff data request (OTS-RS-89), the Company seems to argue that since most retail customers do not have interval demand meters, the costs for transmission service cannot be recovered on a demand basis from these customers and therefore the proposed TSC is consistent with how PPL pays for transmission service. This is clearly an unreasonable rationale for its proposed TSC recovery mechanism. Throughout history, it is always the case that residential customers have been billed on a kWh sales basis. This has never been a rationale, however, for the appropriate allocation of generation and transmission costs to rate schedules. The Company is essentially arguing that its rate design billing criteria (kWh sales for RS customers) should form the underlying principle for the allocation of costs to rate schedules. One has nothing to do with the other. It is undisputed that the Company's transmission revenue requirement (as shown in Exhibit SJB-2) is incurred by PPL on both a demand and on an energy basis. There is no reason to ignore this underlying cost information in the design of the TSC. The fact that residential customers would continue to be billed transmission charges on a kWh basis should not impact the appropriateness of allocating PJM transmission charges in a manner reflecting the way such charges are incurred by PPL.

Q. You indicated previously that the Company is estimating a $57 million increase in its transmission revenues associated with providing POLR service. Under the Company's proposed TSC, how is this $57 million transmission revenue increase being recovered from rate schedules?

A. Table 1 shows the percent increases in transmission revenues that the Company is proposing to recover from each of its rate schedules, pursuant to its requested uniform kWh charge in the TSC. Overall, the Company's request reflects a 40% increase in transmission revenues. RS customers would receive an increase of 47.9%, while GS-1 and GS-3 customers would receive a decrease of 4.1% and an increase of 20.6%, respectively, substantially lower than the overall increase of 40%.

Table 1
Increase in Transmission Cost Recovery under PPL TSC Proposal

	Present Transmission Revenues ($000)	PPL TSC Increase ($000)	PPL Increase (%)
RS	49,075	23,505	47.9%
RTS	481	1,773	368.5%
RTD	20	10	47.9%
GS-1	11,800	(478)	-4.1%
GS-3	38,389	7,895	20.6%
LP-4	19,785	9,253	46.8%
IS-P	1,497	820	54.8%
LP-5	9,699	8,051	83.0%
IS-T	7,066	4,061	57.5%
LP-6	1,574	1,313	83.4%
LPEP	39	367	951.9%
ISA	357	-	0.0%
IS-1	10	2	20.7%
BL	37	(1)	-3.9%
SA	81	51	62.7%
SM	16	13	78.0%
SHS	200	155	77.2%
SE	63	48	76.4%
TS	1	1	75.9%
SI-1	0	0	77.5%
GH-1	1,497	313	20.9%
GH-2	338	69	20.4%
Standby	22	18	83.4%
PRS	60	-	0.0%
Total	142,110	57,238	40.3%

Q. What increases is the Company proposing for large industrial rate schedules?

A. As can be seen from Table 1, the Company is proposing an increase of 47% for LP-4 customers and increases ranging from 55% to 83% for its larger customers on Rate Schedules IS-P, LP-5, IS-T and LP-6.

Q. Has the Company explained its rationale for such disparate increases in transmission charges, pursuant to its TSC proposal?

A. No. In fact, the comparison in Table 1 shows the change in revenues between the current unbundled transmission charges based on the unbundled cost of service study used in PPL's 1997 the restructuring proceeding compared to the uniform kWh charge being proposed in the TSC. Though the current unbundled transmission rates do not reflect an exact cost of service based recovery of transmission rates, the charges do reflect the application of cost of service principles to the unbundled transmission revenue requirements by recognizing a demand allocation of demand related transmission costs and the loss differentials among rate schedules for both energy and demand related costs. Moving to a uniform kWh sales based recovery mechanism in the TSC ignores both the demand/energy basis of costs underlying the transmission revenue requirement and also ignores the differential in costs associated with the different voltages at which customers take service under various rate schedules. As a result, high load factor rate schedules whose customers take service at primary and transmission voltages (i.e., LP-4, IS-P, LP-5, IS-T and LP-6) are experiencing substantially greater percentage increases in transmission costs than the Company is

requesting on average from its customers.[2] It is inappropriate to recover these costs on a uniform kWh sales basis, rather than recognizing the cost differences in providing transmission services to each customer class.

Q. Do you have an alternative design for the TSC that would recognize the cost of service differences among customer classes for transmission service?

A. Yes. The most reasonable approach to recover transmission revenue requirements is to employ both a demand and an energy based cost recovery mechanism for transmission charges following the Company's basic TSC proposal. Essentially, the Company's transmission revenue requirement can be classified into demand and energy components (based on the cost classification shown in Exhibit SJB-2, which is based on PJM rate schedules and billings to PPL), and PPL can develop separate TSC charges for demand related costs and energy related costs. Transmission costs would be charged to rate schedules on the basis of the applicable demand and energy charges (at transmission voltages) on which these same costs are incurred by PPL from PJM. Once these charges are established through the revised TSC, individual rate schedule transmission revenue requirements can be easily calculated on both a demand and energy basis and corresponding rate schedule transmission rates can be computed.[3]

[2] PPL's proposal to charge a uniform rate per kWh imposes a significant bias in its TSC rate design, to the detriment of high load factor customers. High load factor customers, who use each kW of demand for many more hours during the month than a low load factor residential customer (principally by using the kW of demand during off peak and weekend periods), are being penalized under the Company's rate design because they are being effectively charged a higher kW demand charge for transmission service than lower load factor customers. In fact, the cost of the service, for demand related transmission services, is the same per kW (after adjusting for losses). This provides a disincentive for large customers to operate efficiently, by using energy during off-peak periods.

[3] PPLICA's proposal in this case is to incorporate the FERC approved PJM billing method and allocations into the TSC. Currently PJM allocates the PPL zonal 1 CP (after removing UGI and FERC loads) on the basis of customer 5 CP demands. If this allocation approach changes, pursuant to a FERC tariff change, this revised method should be incorporated into the TSC. PPLICA, in fact, supports a 1 CP allocation of all demand related PJM transmission charges to PPL.

For classes for which customers are billed on interval demand meters, such as Rate Schedules LP-4, LP-5, IS-P, IS-T and LP-6, customers can be charged directly based on the customer' allocated zonal coincident peak demand responsibility that is determined by allocating the PPL zonal peak (after removing UGI and FERC load) on the basis of each customers contribution to the PPL 5 highest peaks ("5 CP").[4] For other customer classes, such as residential service, customers would be charged on a single kWh sales rate that is determined for the specific rate schedule based on the combined demand and energy TSC charges. This allocation methodology is entirely consistent with the PJM allocation of these costs to PPL.

Q. Would you please explain the specific approach that you are recommending for the design of separate demand and energy related TSC charges?

A. The first step in the process is to classify the Company's transmission revenue requirements into those costs that are billed by PJM to PPL on the basis of demand, and those costs that are billed on the basis of energy. This classification has already been shown in the Exhibit SJB-2. The next step in the process is to determine the appropriate billing determinants that should be associated with each of the two components of transmission revenue requirements. For the demand related costs, which is estimated to be $146 million in the test year, the appropriate billing determinants are the sum of each rate schedule's contribution to the PPL zonal coincident peak, as determined by the rate schedule share (in percent) of the

[4] LP-4 hour metered customers are interval metered. For other LP-4 customers, these customers could be billed on the load profile based 5 CP demands.

PPL 5 CP demand, times the PPL zonal peak (after removing UGI and FERC loads). This produces the rate schedule "POLR Mw load responsibility". This calculation is maintained by the Company for each of its customers ("tagged demand") and provided to PJM for billing purposes, as customers migrate between POLR service and EGS service.[5] Baron Exhibit___(SJB-3) contains a copy of the Company's response to PPLICA Interrogatory No. I-11 that explains the specific PJM billing method.

Using the test year POLR mW load responsibility (as determined above) for all applicable rate schedules, the demand related TSC charge ("TSC_D") is calculated to be $22,426 per mW per year for each mW of demand on the PPL system associated with POLR customers.[6] This translates into a monthly rate of $1.869 per kW of tagged demand. The corresponding energy charge, following the same approach would be $0.00143 per kWh. This is the charge associated with the TSE energy charge ("TSC_E").

Q. Would these be the corresponding rates that would actually be charged to each of PPL's retail POLR customers?

A. No, not for most customers. Both of these charges, the TSC_D and the TSC_E, are at the transmission voltage level and would have to be adjusted for losses except in the case of rate schedules for which service is supplied at the transmission voltage level (e.g., LP-5). In addition, in the case of the TSC_D demand charge, this charge is associated with a customer's

[5] The tagged demand is actually that customer's 5 CP share of the PPL zonal 1 CP peak obligation.
[6] As discussed previously, for Rate Schedules ISA and PRS, the TSC does not apply, pursuant to the Company's proposal. As such, the billing determinants for these customers would not be included in the development of the TSC. In addition, the revenues for transmission service produced by Rate Schedules ISA and PRS ($417,000 during the test year) should be credited against the respective demand and energy revenue requirements that are to be recovered from other POLR customers.

contribution to the PPL zonal CP demand at transmission voltage, as used by PJM in its allocation of Network Integrated Transmission Service ("NITS") transmission charges as between POLR and EGS service. In order to develop the rate for most rate schedules, it is necessary to apply each rate schedule's POLR mW load responsibility billing determinants (at the transmission voltage level) and its kWh energy use (again at the transmission voltage level) to the respective TSC charges. For interval metered customer classes, customers could be charged the TSC_D directly based on the customer's own tagged CP demand. For Rate Schedules LP-5, LP-6 and IS-T, on which customers take service directly at transmission voltages, these customers would be charged exactly the TSC_D rate, adjusted for a 12-month billing basis, and the TSC_E. For customers who are interval metered and take service at a lower voltage rate, these customers would be charged the same monthly equivalent of the TSC_D based on the customer's own tagged CP demand, but the TSC_E would be adjusted for losses so that it could be applied directly to billing kWh.

Q. Would you please provide an example of the calculation of each rate schedule's *transmission* revenues and the corresponding rates under your TSC_D and TSC_E modification to the Company's proposal?

A. Yes. Table 2 shows the calculation for the residential class (RS, RTS, RTD and BL). Using the $22,426 per mW year TSC_D charge and $0.00143 per kWh charge shown in Exhibit SJB-2, the residential revenue requirement would be equal to its POLR load responsibility of 3,325.9 mWs and its POLR kWh responsibility at the transmission voltage level (times the respective TSC_D and TSC_E charges, as shown in Table 2. The corresponding demand charge revenues for RS and BL customers would be $74,586,167 for the TSC_D portion of

the transmission charge and $20,020,680 for the TSC_E charge. This reflects an allocation of the transmission revenue requirement associated with PJM charges to PPL following the same basis as used in the actual PJM billing to PPL for transmission service. The combined RS transmission revenue requirement is $94,786,847 which translates into a per kWh sales rate (which includes losses) of $0.00714 per kWh for RS customers.

Table 2
Calculation of Residential Class Transmission Charges

RS POLR Mw Load Responsibility		3325.9
TSC_D	$	22.426
RS Transmission Demand Charges		74,586,167
RS POLR kWh Energy at Meter		13,280,052,825
RS Transmission Loss Factor		1.06086
RS POLR kWh Energy at Transmission		14,088,276,840
TSC_E	$	0.00143
RS Transmission Energy Charges	$	20,200,680
RS Total Transmission Charges	$	94,786,847
RS Transmission Rate ($/kWh)	$	0.00714

Q. Have you performed similar calculations for each of the Company's rate schedules?

A. Yes. Baron Exhibit ____(SJB-4) shows the development of the overall transmission rate for each of the Company's rate schedules using the TSC_D and TSC_E modification to the Company's TSC proposal that I just discussed. Column 1 of SJB-4 shows the POLR mW load responsibility for each customer class. Column 2 of SJB-4 shows the POLR kWh, at the billing (meter) level, for each rate schedule. Applying loss factors to these billing determinants (Columns 1 and 2) and then multiplying the respective results by the TSC_D and TSC_E factors calculated in Exhibit (SJB-2), produces the respective demand and energy

charges shown in Columns 3 and 4. These revenue requirements are then unitized by either a kWh sales (at the meter) billing determinant (for residential, GS and other customers) or on a demand and energy basis for interval metered rate schedules and other rate schedules that could be billed on their "tagged" demand (5 CP share of the PPL 1 CP). The resultant total transmission revenue requirements for each rate schedule are shown in Column 7. Columns 8 and 9 compare the cost of service based transmission revenue requirements shown in Column 7 to PPL's proposal that ignores cost differences among customer classes for transmission service and simply recovers the rate on a uniform kWh sales basis. Table 3 provides a summary of the PPLICA proposed TSC charges, by rate schedule, compared to PPL's proposal.

Table 3
Increase in Transmission Cost Recovery under TSC Proposals

	Present Transmission Revenues ($000)	PPL TSC Increase ($000)	PPL Increase (%)	PPLICA TSC Increase ($000)	PPLICA Increase (%)
RS	49,075	23,505	47.9%	42,506	86.6%
RTS	481	1,773	368.5%	2,363	491.2%
RTD	20	10	47.9%	17	86.6%
GS-1	11,800	(478)	-4.1%	(1,005)	-8.5%
GS-3	38,389	7,895	20.6%	903	2.4%
LP-4	19,785	9,253	46.8%	4,323	21.9%
IS-P	1,497	820	54.8%	346	23.1%
LP-5	9,699	8,051	83.0%	4,867	50.2%
IS-T	7,066	4,061	57.5%	521	7.4%
LP-6	1,574	1,313	83.4%	418	26.6%
LPEP	39	367	951.9%	311	804.9%
ISA	357	-	0.0%	-	0.0%
IS-1	10	2	20.7%	4	40.1%
BL	37	(1)	-3.9%	8	21.3%
SA	81	51	62.7%	58	71.4%
SM	16	13	78.0%	14	87.6%
SHS	200	155	77.2%	174	86.7%
SE	63	48	76.4%	54	86.0%
TS	1	1	75.9%	1	85.4%
SI-1	0	0	77.5%	0	87.0%
GH-1	1,497	313	20.9%	1,134	75.7%
GH-2	338	69	20.4%	254	75.0%
Standby	22	18	83.4%	11	50.5%
PRS	60	-	0.0%	-	0.0%
Total	142,110	57,238	40.3%	57,282	40.3%

Q. In PPL's proposed TSC, the Company is requesting a reconciliation factor for net over or under collection of charges associated with transmission service. Do you recommend that the TSC_D and TSC_E modifications to the Company's proposal also include a reconciliation factor?

A. No. Though I believe that a reconciliation factor could be incorporated into the modified TSC proposal that I am recommending, I do not believe that such a reconciliation factor is required in the rate. Rather, I recommend that the Company be required to update its TSC

charges (TSC_D and TSC_E) annually. The filing would be made 30-days prior to the annual update and include a set of calculations supporting its proposed charges. Following the Commission's normal procedures, the Company would then be able to implement its updated TSC_D and TSC_E charges, subject to a review by the Commission's Audit Bureau, as well as other parties.

Q. Would your recommendation change, in the event that the FERC approves a PJM rate change that would affect PPL's charges prior to the date of the annual update?

A. Yes. In the event that the FERC approves a PJM rate change, for any of the cost elements that would be incorporated into the TSC_D and TSC_E charges, I believe that it would be appropriate for the Company to recover such FERC approved changes on an interim basis, prior to the annual update. In this event, the Company should file such changes 30-days prior to the implementation of new rates, again subject to Commission audit review. In this case, using the same billing determinants used in the development of the initial TSC_D and TSC_E rates, the Company would be permitted to recover any increases or decreases in FERC approved PJM OATT tariff charges.

Q. Are you recommending that there be no reconciliation of over or under recoveries of past transmission revenues?

A. Yes. The proposal that I am recommending would not incorporate any retrospective reconciliation of PJM transmission charges relative to actual transmission revenues recovered from customers on an annual basis. The annual update that I am recommending would be prospective only. To the extent that billing determinants or other factors changed

(other than the FERC approved OATT rates themselves, including refunds) there would be no update except on an annual basis and then, the update would only have prospective rate effect.

Q. Why do you believe that it is not necessary to incorporate a retrospective reconciliation into your TSC_D and TSC_E charges?

A. Though such a reconciliation could be incorporated into the TSC_D and TSC_E charges that I am recommending, I believe that there is really no reason for such a reconciliation factor. In the event that a FERC approved PJM OATT rate change occurs during the rate year (prior to the annual update), this would be incorporated into the transmission charges upon 30-days notice by the Company. For other changes that may affect the transmission revenue requirements (such as changes in PPL billing determinants pursuant to its PJM billings), I believe that these would be relatively small compared to the overall transmission revenue requirement. Other factors that could influence a difference between the revenues collected for transmission service from retail customers and the actual charges from PJM to PPL for such service would be primarily associated with retail billing determinants. However, under the approach that I am recommending, wherein costs would be recovered from customers on a demand basis for interval metered customers and from residential customers or non-interval metered rate classes on an energy basis, the recovery of costs on a TSC demand and TSC energy basis would mitigate, to some extent, billing determinant changes during the rate effective period, especially if the change is due to a transfer of customers between POLR and EGS service. As such, I do not believe that it is necessary to incorporate a reconciliation component into the TSC_D and TSC_E rates.

In addition, the possibility of customers switching to EGSs creates inequities and additional layers of complexity that did not exist prior to direct access. The TSC is paid only by POLR load customers. Due to the customer's decisions regarding competitive supply, it is possible that a customer that paid the TSC during a year in which PPL over-collected TSC revenues could be served by an EGS the following year and not obtain a credit against their transmission charges to reflect the prior period over-collection. Similarly, a customer that purchased supply from an EGS during one year and paid that EGS in full for transmission and ancillary services could be forced to pay a surcharge to PPL if it switches back to POLR service.

Q. Have you prepared a tariff rider that reflects your transmission service charge proposal?

A. Yes. Baron Exhibit ____(SJB-5) contains a copy of the PPLICA Transmission Service Charge tariff rider, reflecting the changes to the PPL proposal that I just discussed.

III. ALLOCATION OF THE DISTRIBUTION REVENUE REQUIREMENT AMONG RATE SCHEDULES

Q. Would you please describe the approach recommended by PPL to apportion its distribution revenue requirement increase in this proceeding?

A. As discussed briefly by PPL witness Kasper, the Company has attempted to move class rates of return towards the system average return, subject to a constraint that no rate schedule should receive a total increase of more than 10%. This "total increase constraint" imposed by the Company of 10% includes both its proposed distribution revenue requirement increase of $162 million, as well as its pass-through of PJM cost increases pursuant to its TSC. The rate of return results relied upon by the Company and used as a criterion in Mr. Kasper's testimony to allocate the increase in this case reflects the cost of service associated with distribution costs on the PPL system. For transmission costs, the Company is proposing a direct pass-through of PJM costs through its TSC proposal, but does not provide for a cost-based transfer of those costs to individual rate classes, as I previously discussed.

As such, it is appropriate to examine the allocation of the distribution revenue requirement increase separately from that of the transmission revenue requirement increase. Again, the cost of service studies in this case are all focused on the distribution system costs, not the transmission system costs. Though the Company's TSC proposal does not provide for a cost-based recovery of transmission costs, the PPLICA proposal that I previously discussed does recover PJM transmission charges to PPL on a cost of service basis from rate schedules. Since the PPLICA transmission rate recovery proposal is based on a pass-

through of PJM transmission charges to PPL and also recognizes the nature of the charges from PJM (demand and energy related), there is no need to consider cost of service results with regard to the transmission costs. However, for distribution costs, the cost of service study is the appropriate basis on which to evaluate the Company's proposal for the allocation of its requested increase and is the appropriate basis to make modifications to the Company's proposal.

Q. Have you reviewed the Company's cost of service study in this case?

A. Yes. In general, I do not have objections to the Company's filed cost of service study and believe that it is a reasonable basis upon which to make a determination of the appropriate allocation of any Commission authorized increase in distribution revenue requirements.

Q. What are the results of the Company's test year cost of service study, with regard to class rates of return on distribution investment and the subsidies existing between rate classes?

A. Baron Exhibit ____(SJB-6) shows a summary of the Company's cost of service results for the test year under present rates and at the proposed rates recommended by PPL for distribution cost recovery in this case. The exhibit shows both the rate of return on distribution investment at present and proposed rates for each rate schedule as well as the dollar subsidy incorporated into present and proposed rates.

A negative value for the "present subsidy" means that this rate schedule is receiving a subsidy. A positive value indicates that the rate schedule is paying a subsidy. Table 4

summarizes the rates of return and the dollar subsidies for each rate schedule at present rates. As can be seen from the table, residential RS customers are receiving a current subsidy of $51 million from other rate schedules at present rates. The 1.6% rate of return paid by residential RS customers is less than half of the average system rate of return of 3.91% at present rates.

Table 4
Distribution ROR and Subsidy
at Present Rates

Rate Class	Present Rate of Return	Present Subsidy
RS	1.60%	(51,291)
RTS	-3.95%	(5,932)
GS-1	9.28%	17,580
GS-3	10.50%	30,048
LP-4	10.64%	7,561
IS-P	14.46%	731
LP-5	23.58%	730
IS-T	87.15%	1,087
LP-6	80.56%	201
LPEP	11.15%	109
ISA	107.75%	538
GH	9.76%	2,101
SL/AL	1.03%	(3,469)
L5-S	5.65%	6
Total	3.91%	(0)

Q. Can you explain why the distribution rates for customers on Rate Schedules LP-4, LP-5, LP-6, IS-T and IS-P contain such significant subsidies?

A. The subsidization exists because the current distribution rates recover significantly more costs than are properly allocated to these rate schedules. PPL's cost of service study compares the distribution revenues paid by each rate schedule to a cost based allocation of each component of distribution revenue requirements (e.g., return on invested capital, expenses, etc.). The results summarized in Table 4 clearly show that Large C&I rate schedules are currently paying distribution rates that are significantly above any reasonable measure of cost. The subsidy problem has not materially improved under PPL's proposed rates.

Baron Exhibit__(SJB-7) shows a comparison, for Rate Schedules LP-4, LP-5, LP-6, IS-P and IS-T, between PPL's proposed distribution rates and the rates that would be applicable if each of these rate schedules only paid their fully allocated cost of service. The exhibit shows, for example, that customers on rate schedule LP-4 will pay distribution rates that are in excess of cost by more than $1.00 per kW month. For an LP-4 customer with a monthly billing demand of 4,000 kW, this would equate to an overpayment of over $4,000 per month, or $48,000 per year. For an IS-P customer with a monthly billing demand of 1,500 kW, the overpayment would be over $2,800 per month, or $33,600 per year. There is no reason that large customers should have to continue paying these subsidies in their distribution rates.

Q. What is the Company's proposal to mitigate these subsidies, following the implementation of its requested $162 million increase?

A. As can be seen from Exhibit SJB-6, the Company has actually proposed to increase the subsidies received by residential customers under proposed distribution rates. These results are summarized in Table 5. As can be in seen in Table 5, the Company is proposing a subsidy of $78 million to residential RS customers under proposed distribution rates. This is a 52% increase in the dollar subsidy received by residential customers. At the same time, the subsidies paid by LP-4 customers will increase by 68% at proposed rates. This is hardly a mitigation of the subsidy problem for distribution revenue requirements on the PPL system. For other large customer classes (IS-P, LP-5, IS-T and LP-6), the dollar subsidy issue is not as large because there is very little distribution plant assigned to these classes. Customers on these schedules take service primarily at transmission voltages. However, the impropriety and inequity of the subsidy is just as important to these customers as to any other customer class contributing to this subsidy.

Table 5
Comparison of Subsidies at Present and PPL Proposed Rates

Rate Class	Subsidy @ Present Rates	Subsidy @ Proposed Rates	Difference
RS	(51,291)	(77,823)	(26,533)
RTS	(5,932)	(9,064)	(3,132)
GS-1	17,580	24,084	6,504
GS-3	30,048	51,393	21,345
LP-4	7,561	12,697	5,135
IS-P	731	782	52
LP-5	730	576	(154)
IS-T	1,087	458	(629)
LP-6	201	92	(110)
LPEP	109	116	7
ISA	538	511	(27)
GH	2,101	3,415	1,315
SL/AL	(3,469)	(7,275)	(3,806)
L5-S	6	39	33
Total	(0)	0	0

Q. Didn't Mr. Kasper indicate in his testimony in this case that the Company has moved class rates of return towards the system average under its distribution rate proposal?

A. Yes. Though the relative rate of return indices have moved somewhat towards the system average rate of return, the dollar subsidies have actually worsened under the Company's proposed allocation of its distribution revenue increase. *Since it is* the dollar subsidies that customers pay (for example, LP-4 customers), the focus should be on the dollar amount of such subsidies and not necessarily the relative rate of return index.

Q. Do you believe that the Company has sufficiently mitigated its distribution revenue requirement subsidies among rate schedules in its revenue allocation proposal?

A. No. The Company's distribution rates have been fixed since January 1999 under the restructuring plan. In fact, the Company's distribution rates, though previously bundled, have not changed since the Company's rate case in 1995. Given the substantial disparities between the rates currently paid by some distribution customers and the cost of providing distribution service, the Company's rates should be designed to more fully mitigate and reduce subsidies, following any Commission authorized increase in this proceeding.

Q. What are the increases in distribution revenues being proposed by PPL in this case?

A. Baron Exhibit _____(SJB-8) summarizes the distribution revenue increase proposed by PPL in this case. Overall, distribution revenues will increase 32.8% if the Company is authorized its entire $162 million increase request. Residential customers on Rate Schedules RS and RTD will receive a 27.5% increase in distribution rates, an amount that is actually less than the system average increase.

Also shown on Exhibit (SJB-8) is the impact of the distribution rate increase on total present revenues for each rate schedule. On an overall basis, PPL's distribution revenue increases will result in a 6.1% increase in total revenues for the system and 7.5% for the residential class. This analysis, which is similar to schedules presented by PPL in its filing, assumes that no change is made to the transmission related revenues. Thus, the overall 6.1% increase does not include the impact of the $57 million transmission increase that will be recovered through the TSC. However, for comparative purposes, this analysis reasonably presents the results of the Company's recommendation with regard to the impact of the distribution rate increase only.

Q. What types of increases would have to be implemented if all subsidies were removed under the Company's proposed $162 million increase request?

A. Baron Exhibit ____(SJB-9) shows the results of an allocation of the requested increase in distribution revenues in this case under the assumption that all classes produce an equal rate of return at proposed rates. The increase in distribution revenues for the system remains at 32.8%, while the RS and RTD rate schedules would receive 54% increase in distribution rates and a 14.7% overall increase in total revenues. Other rate classes, for example LP-4, would receive decreases, if all subsidies were removed under proposed rates. Again, this schedule does not include any impact from the Company's proposed transmission rate increase.

Q. Are you recommending that all subsidies be removed in this proceeding associated with distribution rates?

A. Yes, this would be the appropriate basis to design PPL's rates in this case. However, we recognize that it may be necessary to accommodate gradualism and phase-in the subsidy reductions over a three-year period. The removal of distribution rate subsidies between classes is an appropriate goal that should be implemented by the Commission. I am recommending that the current dollar subsidies associated with distribution rates be reduced by approximately 50% for each rate schedule in this case, with subsequent 25% reductions in the next succeeding two years. The recommendation that I am making would reduce the dollar subsidies in present distribution rates [shown in Baron Exhibit (SJB-6)] by 50% in the first year, except in the case of Rate Schedules IS-T and LP-6 for which the Company has proposed somewhat larger subsidy reductions. Since these two rate schedules take service at transmission voltage, the impact of the "greater than 50% subsidy reduction" proposal by PPL is not substantial with regard to the impact on other rate classes.

Baron Exhibit _____(SJB-10) shows the results of the analysis that I am recommending to allocate the distribution revenue requirement increase in this case. Though this analysis is based on the Company's requested $162 million increase, the 50% subsidy reduction criterion should be applied to any Commission authorized increase for PPL. The approach shown in Baron Exhibit (SJB-10) is to allocate the proposed $162 million increase in such a manner that the subsidies at present rates [(shown in Exhibit (SJB-6)] are reduced at proposed rates by 50%. The only exceptions to this criterion are for Rate Schedules IS-T and LP-6 for which I have accepted the Company's proposed rates.

In order to maintain the "50% subsidy reduction criterion" for residential and smaller customer classes, I am recommending that the revenue short-fall (which is very small) associated with adopting the Company's increase proposal for IS-T and LP-6 be assigned to Rate Schedules LP-4, IS-P, and LP-5. Except for that small adjustment, all of the rate schedules will pay or receive subsidies at proposed rates at approximately 50% of the level (in dollar terms) that exist at present rates.

Q. How does your proposed allocation of the Company's distribution revenue requirement increase compare to the Company's proposal?

A. Table 6 summarizes the PPL distribution increase recommendation compared to the PPLICA proposal that I am recommending. The first three columns in Table 5 show the dollar increase, the percent increase on distribution revenues and the overall increase (assuming no change in transmission rates) under PPL's proposal. The second three columns show the corresponding amounts under the PPLICA recommendation that reduces subsidies by 50% at proposed rates. It is important to remember that these increases are all premised on the Company actually receiving its entire $162 million increase.

Table 6
Comparison of PPL and PPLICA Proposed Distribution Increases

Rate Class	PPL Proposed Increases Increase $	PPL % Increase on Dist Rev	PPL % Increase on Total Rev	PPLICA Proposed Increases Increase $	PPLICA % Increase on Dist Rev	PPLICA % Increase on Total Rev
RS	80,963	27.5%	7.5%	133,141	45.3%	12.3%
RTS	568	16.2%	2.4%	6,666	189.8%	28.3%
GS-1	22,016	35.8%	10.2%	6,722	10.9%	3.1%
GS-3	43,100	51.2%	6.6%	6,731	8.0%	1.0%
LP-4	10,750	49.7%	3.3%	1,918	8.9%	0.6%
IS-P	383	22.0%	1.9%	(27)	-1.6%	-0.1%
LP-5	19	1.2%	0.0%	(187)	-11.6%	-0.1%
IS-T	(565)	-38.8%	-0.7%	(565)	-38.8%	-0.7%
LP-6	(98)	-34.6%	-0.3%	(98)	-34.6%	-0.3%
LPEP	91	29.0%	1.9%	30	9.5%	0.6%
ISA	0	0.0%	0.0%	(242)	-37.2%	-4.3%
GH	2,971	47.7%	8.8%	606	9.7%	1.8%
SL/AL	2,100	11.9%	8.8%	7,640	43.2%	32.1%
L5-S	47	128.1%	4.1%	10	28.6%	0.9%
Total	162,345	32.8%	6.1%	162,345	32.8%	6.1%

Table 7 shows the impact of the PPLICA recommendation on an assumption that the Company received $120 million of its distribution revenue requirement increase request in this case. Again, this analysis is for illustration purposes only and is not based on any

analysis of the reasonableness of the Company's revenue requirement request in this case. I am recommending PPLICA's proposed rate schedule allocation for any Commission authorized increase, and this can easily be accomplished by simply scaling back the allocation to the Commission approved revenue requirement level.[7]

Table 7
PPLICA Distribution Revenue Increase at $120 Million

Rate Class	Increase $	% Increase on Dist Rev	% Increase on Total Rev
RS	105,180	35.8%	9.7%
RTS	5,716	162.7%	24.3%
GS-1	2,601	4.2%	1.2%
GS-3	986	1.2%	0.2%
LP-4	502	2.3%	0.2%
IS-P	(115)	-6.6%	-0.6%
LP-5	(234)	-14.6%	-0.1%
IS-T	(581)	-40.0%	-0.7%
LP-6	(101)	-35.7%	-0.4%
LPEP	11	3.4%	0.2%
ISA	(248)	-38.2%	-4.4%
GH	153	2.5%	0.5%
SL/AL	6,124	34.6%	25.7%
L5-S	6	17.5%	0.6%
Total	120,000	24.3%	4.5%

Q. Do you have any recommendations in regard to the remaining 50% of the subsidy in present rates that is not being removed by your proposed allocation of the Company's authorized increase in this case?

[7] Any Commission approved adjustment (reduction) to PPL's requested $162 million increase should be allocated to rate schedules following the percentage distribution shown for the hypothetical $120 million allocation in Table 7and used to reduce the PPLICA recommended dollar increases (or decreases) shown in Table 6.

A. My recommendation to address the remaining subsidies is to adjust rates such that 25% of the additional remaining subsidies are removed in each of the successive years after the first year of the authorized increase approved in this case. Under this approach, 50% of the current present rate subsidies would be removed initially, with all the remaining subsidies removed by the third year that new rates are in effect. This recommendation would maintain PPL in a revenue neutral position during this three-year time period. However, individual class rates for distribution service would adjust at the beginning of each successive year over the next three years such that all subsidies are removed from distribution rates that would be effective at the beginning of the third year.

Q. Assuming that the Company receives $162 million distribution revenue requirement increase in this proceeding, and that the Company also receives its requested $57 million transmission revenue requirement increase, what would be the overall impact on each rate schedule under the PPLICA recommendations associated with the TSC and the allocation of its distribution increase?

A. Baron Exhibit _____(SJB-11) shows a comparison between the PPL proposed increases for each rate schedule for both distribution and transmission, compared to the PPLICA proposed increase. This analysis is based on an assumption of no shopping. The main impact of this assumption is that transmission revenue requirements are imputed for shopping customers. By assuming no shopping, the overall impact of each rate schedule can be more fairly represented since both transmission and distribution impacts are applied consistently for the same level of billing determinants for each rate schedule (i.e., no shopping for any rate schedule). Of course, as indicated previously, this analysis is

premised on an assumed authorized increase of $162 million for distribution revenues in this case. Using the same hypothetical assumption that the Company only receives $120 million of its requested distribution, the increases overall for each customer class would be substantially less. Baron Exhibit (SJB-12) shows the total impact of a hypothetical $120 million authorized distribution increase.

IV. PPL'S PROPOSED DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

Q. Have you reviewed PPL's proposal to implement a Distribution System Improvement Charge ("DSIC") in this proceeding?

A. Yes. As described in the testimony of PPL witnesses and in the proposed tariff, the DSIC is an automatic adjustment clause that would recover incremental fixed distribution system costs ("depreciation and pre-tax return"). The charge would be updated annually and recovered on a kWh sales basis from all rate schedules except LP-5, LP-6, IS-T, IS-A and LPEP, which purchase service at transmission voltage.[8]

Q. What is PPL's rationale underlying its request for a DSIC?

A. PPL witness Douglas Krall discusses the Company's proposed DSIC. Based on his testimony, it appears that the primary rationale for the charge is that the Company expects to make additional distribution related investments in the future and there would be no means to recover the cost of this additional investment, absent a DSIC or a traditional base rate case.

Q. Did PPL identify any "changed circumstances" that would necessitate a DSIC from a financial standpoint?

A. No such circumstances have been identified that would justify an automatic adjustment clause for certain distribution related investments. The Company has always made such investments and has previously (except for the rate freeze period) had the opportunity to recover its costs, including a fair rate of return, by filing a base rate proceeding. PPL

once again has such a right and can file a base rate proceeding at any time that the Company deems it is required to permit PPL an opportunity to adjust distribution rates so that it can earn a return on all of its investments.

Essentially, PPL's proposal in this case for a DSIC is to create a mechanism that would largely insulate the Company from detrimental effects of regulatory lag, without providing consumers the opportunity to benefit from potential offsetting cost decreases elsewhere or sales increases that may otherwise obviate the need for an increase, despite additional distribution plant investment.

Q. Has the Company provided any mechanism in its DSIC to provide affected consumers the opportunity to benefit from distribution plant retirements or depreciation that may offset the increases associated with the DSIC?

A. No. The only provisions included in the Company's proposal are those designed to reflect cost increases. There are no provisions to reflect potential cost decreases. For example, there is nothing in the DSIC that would reflect potential productivity increases (e.g., lower maintenance expenses) due to the addition of more modern distribution facilities. Under PPL's proposal, customers would be charged the cost of the new investment and the Company's shareholders would receive the benefit (if any) of productivity increases. This is but one example of the potential harm to ratepayers from a single issue rate case, which the DSIC represents.

[8] It would also not apply to PR-1 and PR-2 sales above the CBL.

Q. Are there other concerns that you have with the proposed DSIC?

A. Yes. In addition to the potential for the Company to earn excess returns as a result of the DSIC (by failing to provide ratepayers potential offsetting cost savings or revenue increases due to customer consumption increases), the DSIC will also lengthen the period, all else being equal, between distribution rate cases. It follows that if PPL is recovering its fixed costs associated with certain of its incremental distribution investments on an automatic basis, while retaining potential offsetting savings, that the Company would file less frequent base cases. The problem with this, in addition to the lost opportunity for the Commission to evaluate the overall distribution revenue requirement is that it also precludes the opportunity of the Staff, OCA and other parties to evaluate the reasonableness of the underlying allocation of distribution revenue requirements to rate classes.

Q. Do you have any concerns with PPL's proposed uniform kWh sales recovery from each rate schedule and customer?

A. Yes. First, I would note that the kWh recovery mechanism is inconsistent with the Company's proposal to convert the distribution rates for many classes into fixed monthly charges (to reflect the fixed nature of most distribution costs). More significantly, the proposed DSIC incorporates a kWh sales recovery factor that essentially allocates the incremental distribution investment to rate schedules on the basis of relative kWh sales, rather than the cost of service allocation factors of number of customers and kW demand used by the Company to assign cost responsibility for distribution related facilities. Table 8 below shows a comparison between the relative allocations among rate schedules of

distribution rate base in the Company's 2004 test year cost of service study compared to the kWh sales "allocator" implicit in the DSIC.

Table 8
KWH Sales Allocation Compared to
Allocation Based on Distribution Rate Base

Rate Class*	DSIC kWh Sales Allocation	Allocation of Distribution Rate Base**
RS, RTD	42.5%	64.3%
RTS	1.3%	2.3%
GS-1	6.7%	9.8%
GS-3	28.8%	14.6%
LP-4	17.6%	3.6%
IS-P	1.4%	0.2%
GH	1.4%	1.1%
SL/AL	0.4%	4.2%
L5-S	0.0%	0.0%
Total w/o PRS	100%	100%

* LP-5, LP-6, IS-T, LPEP and ISA excluded from DSIC
** 2004 Future Test Year Cost of Service Study

Q. What conclusions do you draw from this comparison?

A. The obvious conclusion to draw is that PPL's proposed kWh DSIC recovery mechanism does not track the cost responsibility for the Company's distribution facilities by rate schedule. Under the proposed DSIC, the residential class would be allocated about 43% of the fixed costs associated with incremental distribution facilities (covered by the DSIC). This compares to the Company's cost of service distribution related rate base allocation in its 2004 test year cost study of 64% to the residential class. Similarly, for Rate Schedule LP-4, the DSIC kWh allocation would be 18%, while a cost based allocation would only be 4%. The DSIC proposal, if approved, would actually

exacerbate the already significant subsidy problem with PPL's distribution rates. This is an additional reason to reject the DSIC as unjust, unreasonable and contrary to the public interest.

Q. What is your recommendation to the Commission regarding the proposed DSIC?

A. Based on the reasons that I just discussed, I recommend that the Commission reject the proposed DSIC.

V. SUSTAINABLE ENERGY FUND PROPOSAL

Q. Have you reviewed PPL's proposal to implement a Sustainable Energy Fund ("SEF") at ratepayer expense?

A. Yes. PPL has stated in its direct testimony (Statement No. 7, testimony of Timothy Dahl) that PPL is proposing to extend the current SEF until December 31, 2009, from its otherwise expected termination date of December 31, 2004. As discussed by Mr. Dahl, the SEF is designed to promote the development and use of renewable energy and clean energy technologies, energy conservation and efficiency. Currently, PPL funds the SEF at a level of .01 cents per kWh for all electric energy that the Company distributes to ratepayers.

Q. Are ratepayers currently funding the SEF?

A. No. Mr. Dahl implies in his testimony that PPL's ratepayers have been funding the SEF since its inception, through a charge of .01 cents per kWh. Though the source of the .01 cents per kWh SEF funding may be from the distribution charges assessed on ratepayers, the Company's shareholders are actually providing funding for the SEF by allocating .01 cent per kWh from the Company's distribution revenues to the fund. Effectively, PPL's shareholders agreed to forgo .01 cent per kWh of distribution revenues from its ratepayers that it would otherwise have been entitled to retain as part of the unbundling of its rates in the 1997 restructuring.

In the settlement of the Company's "Restructuring Plan" proceeding (Docket No. R-00973954), PPL agreed to fund the SEF (at .01 cents per kWh) out of the average 1.74

cents per kWh transmission and distribution rate. The Restructuring Settlement did not increase the unbundled distribution charges by .01 cents per kWh to reflect the funding of the SEF. Specifically, the settlement stated that: "The .01 cent per KWH shall not automatically be considered a cost of service element upon expiration of the transmission and distribution rate cap on December 31, 2004". Since the .01 cent per kWh funding reduces PPL's proceeds from distribution rates by an equal amount, PPL's shareholders actually are funding the SEF.

Q. Is PPL proposing to shift the funding to ratepayers in this case?

A. Yes. PPL's filing in this case is requesting full revenues from ratepayers associated with both the distribution and transmission revenue requirements, as well as an additional amount (.01 cent per kWh) for the SEF. As a result, PPL is now including the SEF funding as a cost of service element. PPL has included the cost of the SEF in its proposed distribution rates.

Q. What is PPLICA's position with regard to the proposal to impose a new SEF charge of .01 cents per kWh on all distribution sales?

A. PPLICA opposes the inclusion of SEF funding as an element of distribution cost of service. As I discussed, in the restructuring settlement, all SEF funding was to be made by PPL's shareholders, as a reduction in otherwise available distribution revenues. Now, for the first time, PPL is proposing to charge its ratepayers an added expense, over and above its just and reasonable distribution cost of service amounts, to fund the SEF. The

restructuring settlement explicitly recognizes that the SEF would not automatically be considered to be a cost of service element after December 31, 2004. PPLICA objects to including funding as a cost of service element after December 31, 2004.

PPLICA does not oppose the SEF, only the proposal by PPL to shift the funding burden from PPL shareholders to PPL captive distribution ratepayers. The SEF is not a cost of providing distribution service to PPL's ratepayers and should not be included in its cost of service based charges. The appropriate funding source for the SEF is either private or governmental grants, not from the electric consumers of PPL.

Finally, for some PPLICA members, the annual cost of the SEF charges would approach $20,000 per year and for the entire PPLICA membership the annual cost is $223,000. For Rate Schedule IS-T, for example, PPL has included $196,000 of SEF expenses in the revenue requirement supporting its proposed distribution rate, out of total IS-T distribution revenues (at proposed rates) of $1,150,000. This amounts to over 17% of total IS-T distribution charges at PPL's proposed rates. If all of the subsidies are removed from PPL's proposed rates (i.e., rates are set equal to cost of service), the SEF expenses would comprise over 28% of IS-T distribution charges. The inclusion of the SEF funding increases the IS-T distribution rate by $0.21 per kW per month, compared to the total proposed IS-T distribution rate (with SEF) of $0.932 per kW or the cost based rate (with SEF) of $0.453 per kW. If the SEF funding is removed, the distribution rate for IS-T decreases to $0.712 per kW per month (under PPL's proposal) and $0.243 per kW per month under PPLICA's cost-based rate. This is hardly an insignificant charge.

Q. Please explain why the SEF is not a cost of providing distribution service.

A. As PPL recognized, the SEF is a research and development fund. The projects funded by SEF do not, in any manner, enhance or relate to the distribution service provided to customers. Before the Commission can even consider the merit of the SEF, the proponents must establish that the SEF is related to distribution costs or service and provides demonstrable benefits to distribution service customers. PPL has not done so and, in my opinion, cannot do so due to the nature of the projects for which SEF provides assistance.

The Commission must recognize that the current proceeding is a distribution rate case where parties will review the levels and allocation of distribution-related costs. A significant portion of the SEF projects relate to supply side projects such as providing venture capital for the development of wind farms. As a result, it violates fundamental cost allocation and ratemaking principles to fund the SEF through distribution rates.

Q. Does the "supply side/conservation" purpose of the SEF have other implications for the decision of whether ratepayers should be forced to contribute to the fund?

A. Yes. The purpose of the Competition Act was to deregulate generation supply and to provide customers with the opportunity to access competitive supplies through EGSs. To the extent the SEF has legitimate conservation and efficiency goals, these are not related to distribution service. By forcing distribution service ratepayers to subsidize the SEF, the Commission is essentially reintroducing regulatory mandates on generation service

and supply choices for customers. In addition, because individual customers have the right to choose an alternative "green" EGS, customers that desire to support the policy of "clean" energy can do so without mandatory funding through all customers' distribution rates.

Q. Do you have any other observations regarding ratepayer funding of the SEF?

A. Yes. Through inclusion of the SEF funding in distribution rates, the Company essentially seeks for ratepayers to fund research and development for the renewable energy industry. My review of the materials submitted in this proceeding has not uncovered any authority for the Commission to tax businesses in order to fund research and development activities for another industry. In short, utility distribution rates are not the appropriate vehicle to provide subsidization for the renewable energy industry.

Q. Does that complete your testimony?

A. Yes.