Before the

Pennsylvania Public Utility Commission

PUC Docket No. R-00061346

DUQUESNE LIGHT COMPANY

Direct Testimony and Exhibits of

James T. Selecky

On Behalf of

Wal-Mart Stores East, LP

July 7, 2006
Project 8602

BAI
BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

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Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A James T. Selecky; 1215 Fern Ridge Parkway, Suite 208; St. Louis, MO 63141-2000.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A These are set forth in Appendix A to my testimony.

Q **ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A I am testifying on behalf of Wal-Mart Stores East, LP (Wal-Mart). Wal-Mart purchases electricity from Duquesne Light Company (DLC or Company) primarily on Rate Schedules GM and GL.

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A The purpose of my testimony is to discuss the results of DLC's cost of service study and the allocation of any rate increase that the Pennsylvania Public Utility

Commission (Commission) may grant. I will also discuss the proposed rate design for General Service Small and Medium Rate GS/GM and General Service Large Rate GL. In addition, I will also address DLC's proposed mechanisms to recover FERC jurisdictional transmission service-related costs and costs associated with distribution system improvements and relocation projects. These mechanisms are designated as the Transmission Service Charge (TSC) tracker and the Distribution System Improvement Charge (DSIC), respectively. The fact that an issue is not addressed should not be construed as an endorsement of DLC's position.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A A summary of my conclusions and recommendations is as follows:

1. DLC's distribution cost of service study (COSS) comports with generally accepted cost of service study methods. However, the classification and allocation of certain distribution plant accounts in DLC's distribution cost of service study should be modified to classify a portion of primary voltage distribution lines as customer related.

2. With the above-mentioned modification, the Commission should utilize the results of DLC's distribution COSS for allocation of any approved increase in this case. If the Commission does not direct the Company to modify the COSS in this proceeding, the Company should be directed to modify the classification and allocation of primary distribution plant in the next general rate case.

3. The results of the cost of service study presented by DLC indicate significant rate revenue shortfalls exist for certain customer classes. Certain rate classes are paying rates that are significantly in excess of the cost to serve the class. Other classes are paying rates that are below cost of service. Steps should be taken to reduce those disparities between rate revenue and cost of service.

4. DLC's evaluation of the proposed increase by rate class relative to total cost of service, including the cost of generation and transmission as well as distribution cost is inappropriate. The proposed revenue increase at issue in this proceeding is related to distribution only and any increase approved by the Commission should be evaluated relative to distribution cost of service.

5. I do not support DLC's allocation of the proposed distribution rate increase. If the Commission awards DLC the $143.7 million it has requested in this proceeding, it should allocate the increase uniformly to all rate classes based only on distribution revenues.

6. If the Commission determines that DLC's overall revenue requirement or cost of service is less than the amount requested, the rate increase for rate classes below cost of service should remain at the level resulting from my recommended allocation of the $143.7 million increase. Any reduction in the revenue requirement from the level requested by DLC should be allocated to the other classes based on the cost of service study to bring rates more in line with the actual cost to service.

7. Transmission charges reflected in DLC's rates should reflect cost causation principles. Transmission costs are classified as demand-related costs and are allocated using a demand allocation factor in the COSS. These costs should be recovered from demand-metered rate classes such as General Service Medium using a demand charge only and not a combination of demand and kilowatthour charges.

8. DLC should be directed to file a revised tariff separating rate class GS/GM in the next general rate case. It is my understanding that there are a large number of customers in this class with very diverse load characteristics. At minimum, the class should be split between those customers with demand meters and those without.

9. The Commission should reject DLC's proposal to create a Transmission Service Charge (TSC) tracker and a Distribution Service Improvement Charge (DSIC) mechanism to automatically recover costs related to transmission service and certain distribution system improvements.

10. However, if the Commission approves DLC's proposed TSC and DSIC mechanisms, the costs should be allocated to the various rate classes recognizing cost of service principles. That is, these costs should be recovered recognizing demand cost causation, wherever possible. Distribution costs are classified as demand related and customer related in the Company's COSS. Collection of these costs as a kWh surcharge will send incorrect price signals to demand-metered customers.

Cost of Service Overview

Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A COST OF SERVICE STUDY?

A After determining the total company cost of service or revenue requirement, a cost of service study is used to allocate the revenue requirement or cost responsibility among the customer classes. A cost of service study compares the cost that each customer class imposes on the system to the revenues each class contributes. For example, when a customer class produces the same rate of return as the total system rate of return, it is paying revenue to the utility just sufficient to cover the costs incurred in serving that class. If a class produces a below-average rate of return, it may be concluded that the revenues provided by the class are insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce a below system average rates of return. The class cost of service study is important, because it shows the cost to serve each rate class reflecting cost causation, as well as the rate of return from each class under current and proposed rates.

Q **WOULD YOU PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A COST OF SERVICE STUDY?**

A Yes. Cost of service is a basic and fundamental ingredient in the ratemaking process. In all cost of service studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the cost causation principle.

The first step in the process is to functionalize the costs according to major functions, such as production, transmission and distribution. Another vital step in a cost of service study is classification of the nature of these costs as to whether they vary with the quantity of energy consumed, the demand placed upon the system or the number of customers being served.

Fixed costs are those costs that tend to remain constant irrespective of changes in output and are generally considered to be demand-related. Fixed costs include those costs that are incurred to serve customers that are not related to usage. Variable costs on the other hand are basically those costs that tend to vary with output and are generally considered to be energy-related. Customer-related costs are those that are closely related to the number of customers served, rather than the quantity of energy consumed or the peak demands placed upon the system. An understanding of these concepts is essential to cost of service studies, as well as appropriate rate design. In this case, all the costs that are at issue are either demand or customer-related.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATE DESIGN PROCESS?

A The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost causation, appropriate price signals, conservation and revenue stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve them, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility (and other competitive power suppliers) about the need for new investment. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand and the energy charge that they pay should reflect the cost of providing that energy.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate, such as customer and demand charges, will result in a disproportionate share of revenues being collected from high energy consuming or high load factor customers and send erroneous price signals to all customers.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on actual costs do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the impact on the utility's earnings due to changes in customer use patterns will be minimized. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate expected utility-wide cost changes, such as expected increases in overall revenue requirements, into changes in the rates charged to particular customer classes and to customers within the class. This situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future power cost.

Duquesne Light Company's Cost of Service Study

Q PLEASE COMMENT ON DLC'S PENNSYLVANIA JURISDICTIONAL COST OF SERVICE STUDY.

A Although I have not performed a specific analysis of the various allocation factors, I support the classification and allocation methods employed by DLC with one exception. I generally support DLC's allocation of distribution cost to the various rate classes on demands and number of customers. However, DLC's COSS overstates the portion of distribution plant investment that should be classified and allocated as demand related and understates the customer related portion.

The Company's COSS separates distribution plant investment between *primary and secondary voltage. Primary voltage distribution plant is classified as* 100% demand related. A major factor governing the classification of distribution plant investment is the necessity to provide distribution capacity sufficient to meet the individual demands of customers. However, a portion of distribution investment is necessary just to connect a customer to the system. These investments are customer-related. DLC's COSS makes this distinction for secondary voltage distribution plant. The same distinction should be made for primary voltage distribution plant investment and related expenses.

Q **COULD YOU PLEASE IDENTIFY WHICH PRIMARY VOLTAGE DISTRIBUTION PLANT COSTS DLC CLASSIFIED/ALLOCATED ONLY AS DEMAND-RELATED?**

A Yes. Table 1 below lists the classification of primary voltage distribution plant Accounts 360 through 367 showing DLC's COSS classification and the classification recommended by the National Association of Regulatory Commissioners (NARUC) as presented in their Electric Utility Cost Allocation Manual (NARUC Manual). DLC did not classify any of the cost in these accounts as customer-related.

TABLE 1

Classification of Primary Voltage Distribution Plant

			Per NARUC Manual *		Per DLC COSS **	
Line	Description	FERC Account	Demand Related	Customer Related	Demand Related	Customer Related
1	Land & Land Rights	360	X	X	X	-
2	Structures & Improvements	361	X	X	X	-
3	Station Equipment	362	X	-	X	-
4	Storafe Battery Equipment	363	X	-	X	-
5	Poles, Towers & Fixtures	364	X	X	X	-
6	Overhead Conductors & Devices	365	X	X	X	-
7	Underground Conduit	366	X	X	X	-
8	Underground Conductors & Devices	367	X	X	X	-

* Source: NARUC Electric Utility Cost Allocation Manual, January 1992, Table 6-1, page 87.
** Source DLC cost of service study, Exhibit HSG-2, Exhibit HSG -3 and Exhibit HSG-4A

Q WHICH PRIMARY VOLTAGE DISTRIBUTION PLANT ACCOUNTS SHOULD INCLUDE A CUSTOMER COMPONENT FOR COST ALLOCATION PURPOSES?

A The distribution plant investment cost for Accounts 364, 365, 366 and 367 should have a customer component. DLC must incur costs to construct a distribution line irrespective of the amount (i.e., energy) or rate (i.e., demand) of electricity usage. Therefore, a portion of these distribution line costs is properly classified and allocated as customer-related. The remaining distribution investment is needed to provide sufficient capacity to meet customers' demand when they arise. This portion of the distribution investment is demand-related.

The NARUC Manual clearly recognizes that a portion of primary voltage distribution plant investment should be classified as customer related, as well as demand related. The NARUC Manual describes a typical classification of distribution plant that shows primary voltage overhead and underground lines and line transformers classified as both demand and customer related.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE PRIMARY VOLTAGE DISTRIBUTION COST CLASSIFICATION IN THIS PROCEEDING?

A I recommend that the Commission direct DLC to modify its existing COSS to recognize the customer-related as well as the demand-related costs in primary voltage distribution plant Accounts 364, 365, 366 and 367. The customer-related portion should be determined based on a minimum distribution study. DLC used this type of study to classify the secondary voltage distribution plant investment between demand and customer-related cost. The same type of analysis is appropriate for primary voltage distribution plant investment.

If, however, the Commission accepts the Company's distribution plant classification as filed in this proceeding, I suggest that DLC be directed to reflect the customer-related portion of primary voltage distribution plant in the COSS filed in the next general rate case.

At this time, the Company's COSS as filed is reasonably reflective of cost causation. Therefore, I have utilized the results of the Company's COSS to discuss the allocation of any Commission approved revenue increase and rate design.

Q DO YOU HAVE ANY ADDITIONAL COMMENTS WITH RESPECT TO THE COST OF SERVICE STUDY?

A Yes. DLC points out the diverse nature of the customers on rate schedule GS/GM. The peak monthly metered demand of these customers ranges from 0 kW to over 300 kW. Rate GS/GM has the second largest number of customers of all DLC's rate schedules. Non-demand metered customers account for 25% of the class. DLC states that there is no material difference in either load profiles or the way delivery service is designed, constructed or operated between a typical residential customer and a typical small GS/GM customer. Therefore, the Company proposed to bill the non-demand metered GS/GM customer at the fixed monthly charge and variable energy charge proposed for residential rate RS.

DLC claims that it is proposing to separate the rate into general service small and general service medium with two rate structures to address the diversity of the rate class. However, the proposed tariff does not clearly distinguish between customers on rate GS and customers on rate GM. There is a distinction between customer with demand meters and customers without demand meters. These customers are combined in the Company's COSS. This masks the cost distinctions between the two groups of customers. I recommend that the Commission direct DLC to 1) separate rate class GS/GM into two separate classes in the COSS in the next general rate case and 2) file separate tariffs rather than one tariff for the combined group of customers.

Results of Cost of Service Study

Q HAVE YOU REVIEWED THE RESULTS OF DLC'S COST OF SERVICE STUDY?

A Yes. I reviewed the results of DLC's cost of service study for the 12-month period ending December 31, 2006. The results of the cost of service study are summarized for the major rate classes on **Exhibit JTS-1**. These rate classes comprise approximately 94% of DLC's Pennsylvania jurisdictional rate base.

Q WHAT DO THE RESULTS OF THE COST OF SERVICE STUDY SHOW?

A **Exhibit JTS-1** shows the results of the Company's cost of service study at both the current and the proposed rates. The COSS results include the rate of return, the index of return, and the revenue under or over-collection. **Exhibit JTS-1** also shows the proposed revenue increase by amount and as a percent of present distribution revenue. **Exhibit JTS-1** reflects distribution revenues only, since the only cost components at issue in this proceeding are distribution-related.

The results of DLC's distribution cost of service study indicate that some rate classes, such as residential, are currently paying rates that are less than the cost of serving the customers in that class. Other rate classes are paying rates in excess of cost of service. The customers in rate classes GS/GM and GL are paying rates in excess of the cost to serve them and making up the revenue shortfall from other rate classes.

Q DOES DLC'S FILING INCLUDE A PROPOSED INCREASE IN TRANSMISSION RATES?

A Yes, although the proposal seems premature. DLC's filing indicates that there will be a proposed increase in transmission revenue of $19 million. However, this increase, if approved, would be the result of a FERC proceeding. DLC has not yet filed for an increase in transmission revenue at the FERC. The Company is not requesting permission to implement an increase in transmission rates in January 2007 when the distribution rates resulting from this proceeding would go into effect. Any changes to the transmission rates and rate structure would not be made until after the Company's FERC filing has been approved. Therefore, my analysis of the revenue increase is limited to the proposed increase of $143.7 million for distribution rates only. However, I address the design of transmission rates and the proposed Transmission Service Charge tracker later in this testimony.

Q HOW DOES DLC PROPOSE TO ALLOCATE THE PROPOSED REVENUE INCREASE AMONG THE RATE CLASSES?

A The COSS set the base parameters for revenue allocation. However, DLC claims that strict application of the COSS results would produce a very wide range of class revenue increases and decreases. Therefore, the Company utilized other revenue allocation principles to moderate the potential rate impacts. DLC chose to evaluate the effect of the proposed increase of $143.7 million in distribution rates on a total bill basis including the cost of generation, transmission and distribution service.

Q WHAT PRINCIPLES IN ADDITION TO COST OF SERVICE DID DLC UTILIZE IN DEVELOPING ITS REVENUE ALLOCATION PROPOSAL?

A DLC's filing listed the following principles for allocating the proposed rate increase:

- The increase should result in no rate class have a ROR on distribution rate base of less than 1% or greater than 25%,
- The overall rate increase to any rate class on a total bill basis should not exceed 1.4 times the overall system average increase on a total bill basis,
- *No rate class should receive a revenue decrease on a total bill basis,*
- Each rate class' ROR relative to system average should move closer to system average ROR or "unity", and
- Retail transmission rates will be set to recover each customer class' transmission related cost of service. (Direct Testimony of William V. Pfrommer, Page 6)

As a result of these arbitrary limitations on cost based revenue allocation, even though the cost of service results show that the GS/GM rate schedule should be reduced, it is still receiving a proposed increase. On the basis of distribution costs alone, Rate GS/GM customers are proposed to receive an increase of roughly 36%. Rate GL customers would receive a distribution rate increase of about 110%. DLC's approach significantly increases the disparity between rates and cost of service, i.e., the over collection, for customers on rate GL. In this instance, the over-collection nearly triples from the level at present rates to the level at DLC's proposed rates.

Although it is correct that this "total bill" approach is representative of the impact that a customer would see on its monthly bill, distribution costs are the only costs directly at issue in this proceeding and customers should know how much this portion of their bill is changing. DLC acknowledges that rates should reflect the costs to serve customers to be consistent with fundamental cost allocation principles. Therefore, the impact of the proposed distribution revenue increase should be evaluated relative to distribution costs only and not total costs. This is the only case that provides the Commission with the opportunity to implement cost-based distribution rates and the Commission should seize this opportunity to bring the distribution rate closer to cost of service.

Q WHAT IS YOUR OPINION ON THE PRINCIPLES THAT DLC USED TO ALLOCATE THE REVENUE INCREASES TO THE VARIOUS RATE CLASSES?

A First, the desire to have no rate class have an ROR on distribution rates of less than 1%, or greater than 25%, strays too far away from the basic tenets of cost-based ratemaking.

Second, the criteria that no rate class receives an increase of more than 1.4 times the system average increase on a total bill basis do not result in bringing every rate class closer to cost of service. As a result of the application of this criteria, some rate classes move further away from cost of service at proposed rates as compared to present rates, as measured by the over and under-collections by rate class.

Third, the criteria stating that no rate class should receive a revenue decrease is supportable assuming that the Company receives its requested level of increase of approximately $143.7 million. However, if the Commission is to purely allocate the increase based on the results of the cost of service, that should not prevent a rate class from seeing no increase.

Finally, the fourth criteria states that each class' rate of return relative to the system average should move closer to the system average rate of return, or unity. Based on this measure, DLC's COSS results appear to reflect that proposed rates are moving closer to cost of service relative to present rates. However, a more accurate measure is the over or under-collection that each rate class is paying or receiving.

Q **WAS DLC ABLE TO ACHIEVE ITS REVENUE ALLOCATION PRINCIPLES?**

A No. The Company admits that present rates for certain classes were not reflective of cost of service. Even though DLC can claim that its proposed allocation of the revenue increase is generally consistent with the principles that they established for allocation, the results are not desirable.

Q **DO YOU HAVE ANY COMMENTS TO MAKE REGARDING THE ALLOCATION OF DLC'S PROPOSED RATE INCREASE?**

A As I have previously testified, my preference is to move all rates to cost of service. However, if the Commission grants DLC's requested level of revenue requirement increase, I would be willing to support an allocation of the distribution rate increase based on an equal percentage of present distribution revenues to all customer rate classes.

Q **WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE ALLOCATION OF THE PROPOSED REVENUE INCREASE?**

A My recommendation is that each rate class would see the same percentage increase based on present distribution revenues, not an estimate of total bill. That means at the Company's requested level of increase, each class would see a 51% increase in their distribution revenues. The result of my recommended allocation of the increase at the level the Company is proposing is shown on **Exhibit JTS-2**.

Q IF THE COMMISSION DETERMINES THAT DLC'S OVERALL REVENUE INCREASE SHOULD BE LESS THAN ITS $143.7 MILLION REQUESTED, HOW SHOULD THE INCREASE BE ALLOCATED?

A If the Commission determines the total increase should be less than DLC's requested amount, I recommend that any reduction from the requested amount should be allocated to those classes whose rates are above cost of service or have a rate of return in excess of the overall rate of return that DLC is proposing. Under this scenario, rates would move closer to cost of service.

Q HAVE YOU PREPARED AN EXHIBIT THAT SHOWS HOW YOU WOULD ALLOCATE ANY RATE REDUCTION FROM THE AMOUNT REQUESTED BY DLC?

A Yes. **Exhibit JTS-3** provides an example of how a reduction of $70 million from the amount that DLC is requesting in this case would be allocated to customer classes based on my recommendation.

The allocation of a $70 million reduction from DLC's requested amount would be based on the cost of service results as shown on **Exhibit JTS-2**. The reduction in the revenue requirement would be used to reduce DLC's proposed revenue for those rate classes that are above cost of service, while maintaining my recommended revenue responsibility for those rate classes that are below cost of service. Once the rate class' revenues of rate classes that are over-collecting are at cost of service, any excess reduction would be allocated to all rate classes based on distribution rate base.

Exhibit JTS-3 shows the allocation of a revenue reduction in DLC's proposed revenue based on the Company's filed cost of service study. This analysis would need to be revised if the Commission directed DLC to modify its COSS distribution plant classification methodology as discussed above.

Q PLEASE BRIEFLY DESCRIBE EXHIBIT JTS-3.

A Exhibit JTS-3 shows a reduction in the proposed revenues for DLC of $70 million. This reduction in the proposed revenue is for illustration purposes only. The revenue reduction is first allocated to eliminate the revenues that a rate class is providing above cost of service. For example, the first $46.5 million (the total of the over-collection from rate classes above cost of service) of the assumed $70 million revenue reduction is utilized to eliminate the amount by which rates GS/GM, GL, LP and SM are above cost of service. This analysis is for illustration purposes and only shows DLC's major classes. The additional classes, mainly lighting related, are not included on the exhibit, but would be included in a final analysis. The remainder of the revenue requirement reduction, $23.5 million, is allocated to all rate classes based on rate base.

Q WHAT IS YOUR RECOMMENDATION IF THE DECREASE IN DLC'S PROPOSED REVENUE REQUIREMENT IS INSUFFICIENT TO BRING ALL RATES TO COST OF SERVICE?

A If the reduction to DLC's requested revenue requirement is insufficient to bring all rate classes to cost of service, then the decrease or reduction should be allocated based solely on the over collections or revenue in excess of cost of service.

Rate Design

Q HAVE YOU REVIEWED DLC'S PROPOSED CHANGES TO THE RATE SCHEDULES FOR THE GENERAL SERVICE RATE CLASSES, RATE SCHEDULES GS/GM AND GL?

A Yes. Consistent with the results of its cost of service study, DLC is proposing to move the rates closer to demand-oriented rates and away from energy or kWh-based rates. As a result, the demand charges are being increased and the energy charges are reduced. The long-term plan of the Company is to migrate toward rates that reflect the services provided by a delivery company, the way transmission and distribution systems are designed and operated and the way in which fixed costs are incurred. I strongly support this proposal.

Q DO YOU AGREE WITH DLC'S APPROACH TO PROPOSED DISTRIBUTION RATE DESIGN FOR RATES GS/GM AND GL?

A Not entirely. I believe that a greater proportion of the total distribution revenue requirement should be shifted from the energy charges to the demand charges for rate schedule GM. This would be more consistent with the cost allocation methodology and result in price signals to customers that are more reflective of cost causation principles. The proposed rates for rate schedule GM recovers approximately 67% of the overall distribution revenue requirement through the customer and demand charges. The present rates for rate GM recover approximately 54% of the overall distribution revenues through the customer and demand charges. The proposed rate GL recovers approximately 82% of the overall distribution revenue requirement through the demand charge. The present rate GL recovers approximately 52% of the overall distribution revenues through the demand charge.

The shift in cost from energy charge to demand charge is much greater for Rate GL than it is for Rate GM.

Q DO YOU HAVE A RECOMMENDATION FOR THE RATE DESIGN OF RATES GS/GM AND GL?

A I recommend that the split between demand/customer and energy cost used for Rate GL also be applied to Rate GM. That is, 82% of the overall distribution revenue requirement for Rate GM should be recovered through the demand and customer charges, and the remaining 18% should be recovered through the energy charge. The customer charge should remain at $30.00, the level proposed by DLC.

Distribution System Improvement Charge

Q PLEASE DESCRIBE THE PROPOSED DISTRIBUTION SERVICE IMPROVEMENT CHARGE.

A The Distribution Service Improvement Charge (DSIC) is a proposed mechanism to allow the Company to recover the investment cost of eligible delivery system improvement and restoration projects. The DSIC includes depreciation and pre-tax return for non-revenue producing distribution system improvement projects completed and placed in service. DLC is requesting an additional $3.1 million increase in annual distribution revenues in 2007 and $12.3 million in 2008 under the proposed DSIC mechanism.

Q SHOULD THE COMMISSION APPROVE THE DSIC MECHANISM?

A No. The reasons that this mechanism should not be approved are as follows:

1. *Distribution investment costs are not as volatile as fuel costs, and do not need to* be updated on a more frequent basis than a comprehensive rate proceeding.

2. Providing for an automatic pass through eliminates incentives for the utility to control these costs.

3. An increase in sales will provide revenues that will offset some or all of the additional distribution-related costs.

4. The proposed DSIC constitutes single-issue ratemaking.

5. The proposed DSIC would not permit appropriate regulatory review.

6. If DLC is authorized to automatically pass through costs, the rate revenues the Company collects could exceed its revenue requirement or cost of service.

7. The proposed treatment of costs would result in increasing and decreasing the rates of return of the various rate classes.

8. DLC has not submitted any evidence of financial necessity with respect to the proposed DSIC.

Q HAS THE COMMISSION REJECTED A DSIC MECHANISM IN A RECENT PROCEEDING?

A Yes. A DSIC mechanism was rejected by the Commission in a recent PPL Electric Utilities proceeding. The Order stated:

> "The Company has not demonstrated a need for the DSIC or a need to by-pass the normal ratemaking process.....the Company did not submit evidence that the repairs would not be made if the DSIC is not available. Nor did PPL demonstrate it was approaching serious reliability problems.... Additionally, the Commission notes the current uncertainty associated with its authority to approve automatic adjustment mechanisms beyond our water utilities." (Pennsylvania Public Utility Commission, et. al. v. PPL Electric Utilities Corporation, R-00049255, Opinion and Order, December 2, 2004, Page 23)

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE DSIC?

A My recommendation is that the Commission reject DLC's request to implement the DSIC, for the same reasons that it rejected the DSIC request of PPL Electric.

Transmission Service Charges

Q PLEASE DESCRIBE DLC'S PROPOSED TRANSMISSION REVENUE ALLOCATION AND RATE DESIGN.

A DLC is proposing that retail transmission rates be designed to recover each customer class' transmission related cost of service. The Company claims that this will promote retail competition and mitigate opportunities for arbitrage by customers that shop for electricity. In addition, the Company wants to redesign retail transmission rates to reflect rates for transmission service to all load serving entities within PJM. According to the Company, current retail transmission rates produce the potential for rate differences depending on whether a customer shops for supply service.

Q DO YOU AGREE WITH DLC'S PROPOSED DESIGN OF TRANSMISSION RATES?

A Yes, with one exception. I support the allocation of the transmission costs on the basis of cost of service. DLC states that the cost of transmission service for the total system is $1.465 per kW per month before gross receipts tax (GRT). Since this cost is allocated to the customer classes on a demand basis, transmission service cost recovery should be via a demand charge where possible. It is clear that non-demand metered rate classes such as residential customers will pay for transmission service on a per kWh basis. However, DLC is proposing to recover transmission costs from demand metered Rate GS/GM customers based on both demand and energy charges. The proposed demand charge is $0.45/kW and the proposed energy charge is $0.001489/kWh. This is not reflective of cost causation.

The proposed rate schedule GM recovers approximately 49% of the overall transmission revenue requirement through the demand charge and 51% through the energy charge. Transmission costs are allocated in the COSS on a demand related basis and should be recovered using a demand charge for those customers with demand meters, such as customers on rate GM. I recommend that the charge for rate GM transmission service be set equal to the total system cost of $1.465 per kW per month adjusted for GRT ($1.55 per kW).

Q **PLEASE EXPLAIN DLC'S PROPOSED TRANSMISSION SERVICE CHARGE TRACKER.**

A The Transmission Service Charge Tracker (TSC) is intended to recover transmission service charges incurred by DLC under the PJM Open Access Transmission Tariff (OATT) as a provider of transmission service to retail customers who take Provider of Last Resort (POLR) service from the Company. According to DLC, this will help provide more competitively neutral retail transmission rates over time.

Q **SHOULD THE COMMISSION APPROVE THE TSC MECHANISM?**

A No. The reasons that this mechanism should be rejected are similar to the reasons for rejecting the DSIC. Transmission costs are not as volatile as fuel costs, and do not need to be updated on a more frequent basis than a comprehensive rate proceeding. Also, providing for an automatic pass through eliminates incentives to control costs by the utility.

Q HAS THE COMMISSION APPROVED A TSC MECHANISM IN A RECENT PROCEEDING?

A Yes. A transmission tracker was approved in a recent PPL Electric Utilities proceeding.

Q IF THE COMMISSION APPROVES THE TSC, HOW SHOULD THE TSC COSTS BE COLLECTED FROM RATEPAYERS?

A These costs should <u>not</u> be recovered on a cents per kWh basis for customer classes that are demand metered. The transmission costs for GS/GM customers that are demand metered should be recovered through demand charges. The cost recovery should reflect cost causation and the fact that these costs are generally demand-related as opposed to energy-related.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A Yes, it does.

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Qualifications of James T. Selecky

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and am a principal with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Oakland University in 1969 with a Bachelor of Science degree with a major in Engineering. In 1978, I received the degree of Master of Business Administration with a major in Finance from Wayne State University.

I was employed by The Detroit Edison Company (DECo) in April of 1969 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included evaluation of equipment for use on the distribution and transmission system; equipment performance testing under field and laboratory conditions; and troubleshooting and equipment testing at various power plants throughout the DECo system. I also worked on system design and planning for system expansion.

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of the Rate Research Division, supervisor of the Cost-of-Service Division and director of the Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies; developing fixed charge rates and parameters and procedures used in economic studies; providing a financial analysis consulting service to all areas of DECo; developing and designing rate structure for electrical and steam service; analyzing profitability of various classes of service and recommending changes therein; determining fuel and purchased power adjustments; and all aspects of determining revenue requirements for ratemaking purposes.

In June of 1984, I joined the firm of Drazen-Brubaker & Associates, Inc. (DBA). In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and staff. At DBA and BAI I have testified in electric, gas and water proceedings involving almost all aspects of regulation. I have also performed economic analyses for clients related to energy cost issues.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have testified on behalf of DECo in its steam heating and main electric cases. In these cases I have testified to rate base, income statement adjustments, changes in book depreciation rates, rate design, and interim and final revenue deficiencies.

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Missouri, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming, and the Provinces of Alberta, Nova Scotia and Saskatchewan. I also have testified before the Federal Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Florida, Montana, New York, Oregon and Pennsylvania and the Province of British Columbia. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M expense levels, and rate base adjustments for items such as plant held for future use, working capital, and post test year adjustments. In addition, I have testified on deregulation issues such as stranded cost estimates and rate design.

Q **ARE YOU A REGISTERED PROFESSIONAL ENGINEER?**

A Yes, I am a registered professional engineer in the State of Michigan.

Exhibit JTS-1

DUQUESNE LIGHT COMPANY

Comparison of Cost of Service Components and Proposed Increase
By Major Rate Class for Distribution Only at Present and Proposed Rates $(000)
Twelve Months Ended December 31, 2006

Line	Description	System Total (1)	RS (2)	GS/GM (3)	GMH (4)	GL (5)	GLH (6)	LP (7)	SM (8)
	Present Rates								
1	**Present Operating Revenue**	$ 294,235	$ 155,833	$ 68,146	$ 4,305	$ 33,343	$ 3,184	$ 10,621	$ 9,262
2	**Rate of Return**	2.74%	-0.54%	12.27%	1.49%	5.21%	-3.78%	4.94%	18.91%
3	**Index of Return**	100	(20)	449	54	190	(138)	181	691
4	**Over / (Under) Collection**	$ -	$ (38,095)	$ 39,149	$ (568)	$ 7,789	$ (3,976)	$ 2,247	$ 7,524
	Proposed Rates								
5	**Proposed Operating Revenue**	$ 437,917	$ 212,442	$ 91,589	$ 7,319	$ 68,131	$ 9,092	$ 21,543	$ 9,277
6	**Rate of Return**	9.08%	5.30%	14.60%	8.62%	16.04%	8.62%	15.47%	12.55%
7	**Index of Return**	100	58	161	95	177	95	170	138
8	**Over / (Under) Collection**	$ -	$ (43,867)	$ 22,677	$ (207)	$ 21,891	$ (280)	$ 6,519	$ 1,615
	Proposed Revenue Increase								
9	**Present Distribution Revenue**	$ 279,955	$ 147,575	$ 65,831	$ 4,089	$ 31,636	$ 2,903	$ 10,068	$ 9,129
10	**Proposed Increase**	$ 143,682	$ 56,609	$ 23,443	$ 3,014	$ 34,788	$ 5,908	$ 10,922	$ 15
11	**Percent Increase**	51.3%	38.4%	35.6%	73.7%	110.0%	203.5%	108.5%	0.2%
12	**Relative to Total System**	100	75	69	144	214	397	211	0

Note: An under collection indicates that a customer class rates are below cost of service.
An over collection indicates that a customer class rates are above cost of service.

DUQUESNE LIGHT COMPANY

Alternative Allocation of Company Proposed Revenue Increase
By Major Rate Class - Distribution Only ($000)
Twelve Months Ended December 31, 2006

Line	Description	System Total (1)	RS (2)	GS/GM (3)	GMH (4)	GL (5)	GLH (6)	LP (7)	SM (8)
1	Present Distribution Revenue	$ 279,955	$ 147,575	$ 65,831	$ 4,089	$ 31,636	$ 2,903	$ 10,068	$ 9,129
	Alternative Allocation of Proposed Revenue								
2	Proposed Operating Revenue	$ 437,917	$ 231,573	$ 101,933	$ 6,404	$ 49,580	$ 4,674	$ 15,788	$ 13,947
3	Rate of Return	9.08%	6.95%	17.12%	6.60%	10.14%	1.38%	9.83%	22.59%
4	Index of Return	100	77	189	73	112	15	108	249
5	Over / (Under) Collection	$ -	$ (24,735)	$ 33,021	$ (1,123)	$ 3,340	$ (4,698)	$ 765	$ 6,286
	Alternative Allocation of Proposed Revenue Increase								
6	Proposed Increase	$ 143,682	$ 75,740	$ 33,787	$ 2,099	$ 16,237	$ 1,490	$ 5,167	$ 4,685
7	Percent Increase	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%	51.3%

Note: An under collection indicates that a customer class rates are below cost of service.
An over collection indicates that a customer class rates are above cost of service.

DUQUESNE LIGHT COMPANY

Allocation of Reduction to DLC Proposed Revenue Based on DLC COSS ($000)
Based on Walmart Recommended Allocation of Increase
Twelve Months Ended December 31, 2006

Line	Description	System Total (1)	RS (2)	GS/GM (3)	GMH (4)	GL (5)	GLH (6)	LP (7)	SM (8)
1	Rate Base (Distribution)	$ 1,232,857	$ 630,118	$ 222,791	$ 24,641	$ 170,729	$ 33,138	$ 55,307	$ 25,244
2	Rate Base Allocation	100.0%	51.1%	18.1%	2.0%	13.8%	2.7%	4.5%	2.0%
3	Walmart Proposed Revenue Allocation	437,917	231,573	101,933	6,404	49,580	4,674	15,788	13,947
4	Revenue Over / (Under) Collection *	$ -	(24,736)	33,020	(1,123)	3,340	(4,698)	764	6,286
5	Revenue Reduction	($ 70,000)							
6	Allocation to Reduce Over Collection	$ 46,535	$ -	$ 33,020	$ -	$ 3,340	$ -	$ 764	$ 6,286
7	Allocation of Remainder on Rate Base	$ 23,465	$ 11,993	$ 4,240	$ 469	$ 3,249	$ 631	$ 1,053	$ 480
8	Total Revenue Reduction	$ 70,000	$ 11,993	$ 37,261	$ 469	$ 6,589	$ 631	$ 1,817	$ 6,766
9	Adjusted DLC Proposed Revenue	$ 367,917	$ 219,580	$ 64,672	$ 5,935	$ 42,991	$ 4,043	$ 13,971	$ 7,181

* A negative number indicates that a rate class revenue responsibility is below its cost of service.

BEFORE THE
PUBLIC UTILITY COMMISSION OF THE COMMONWEALTH OF PENNSYLVANIA

PENNSYLVANIA PUBLIC UTILITY COMMISSION V. DUQUESNE LIGHT COMPANY	DOCKET NO. R-00061346

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing document has been served upon the following persons, in the manner indicated, in accordance with the requirements of § 1.54 (relating to service by a participant) in **Docket No. R-00061346**, this day on all parties of record in this proceeding or their attorneys of record:

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Honorable Michael Nemec
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Respectfully submitted,

Dated: **July 7, 2006**

By: [signature]

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	R-00061346
Duquesne Industrial Intervenors and Industrial Energy Consumers of Pennsylvania,	R-00061346C0001
Irwin A. Popowsky, Consumer Advocate, Office of Small Business Advocate,	R-00061346C0002 R-00061346C0005
v.	
Duquesne Light Company	
International Brotherhood of Electrical Workers Local 29,	
Constellation NewEnergy, Inc. and NRG Energy Center, Pittsburgh,	
Citizen Power, Inc., Citizens for Pennsylvania's Future, Retail Energy Supply Association, Strategic Energy, LLC, Direct Energy, LLC, Reliant Energy, Inc., Comcast of California/Pennsylvania/ Utah/Washington, Inc., Community Action Association of Pennsylvania, Wal-Mart Stores East, LP.	RECEIVED SEP 2 8 2006 PA PUBLIC UTILITY COMMISSION SECRETARY'S BUREAU
Intervenors, and	
Office of Trial Staff, Statutory Party	

DIRECT TESTIMONY OF PAUL H. RAAB

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September 14, 2006

DIRECT TESTIMONY OF PAUL H. RAAB

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

A. My name is Paul H. Raab. I am a member of Cablesave, LLC. My business address is 5313 Portsmouth Rd., Bethesda, MD 20816.

Q. PLEASE DESCRIBE CABLESAVE, LLC.

A. Cablesave, LLC is an energy consulting company created to assist cable television operators with managing energy expenses. Among other assistance that we provide, we review how cable operators are billed by electric utilities under various rate schedules and work with cable operators to obtain rates for electric service more in-line with the costs utilities incur to serve the various types of cable loads.

Q. ON WHOSE BEHALF ARE YOU APPEARING TODAY?

A. I am appearing on behalf of Comcast of California/Pennsylvania/Utah/ Washington Inc. ("Comcast"). Comcast of California/Pennsylvania/Utah/ Washington Inc. is a cable television operator owned by Comcast Cable Communications, Inc. ("Comcast Cable") located in the Duquesne Light Company (the "Company") service territory.

I. QUALIFICATIONS

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B.A. in Economics from Rutgers University and an M.A. from the State University of New York at Binghamton with a concentration in

Econometrics. While attending Rutgers, I studied as a Henry Rutgers Scholar.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have been providing consulting services to the utility industry for thirty years, having assisted electric, gas, telephone, and water utilities; Commissions; and intervenor clients in a variety of areas. I am trained as a quantitative economist so that most of this assistance has been in the form of mathematical and economic analysis and information systems development. My particular areas of focus are planning issues, costing and rate design analysis, and depreciation and life analysis. I began my career with the professional services firm that is now known as Ernst & Young, where I was employed for ten years.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A. No. However, I have provided expert testimony before the state regulatory authorities of the District of Columbia, Georgia, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Tennessee, Virginia, West Virginia, and Wisconsin. Also, I have presented expert testimony before the Federal Energy Regulatory Commission, the Michigan House Economic Development and Energy Committee, the Province of Saskatchewan, and the United States Tax Court. Details on the subject matter of the testimony presented are provided in Exhibit 1 (PHR-1).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Comcast is a Duquesne Light Company customer, the majority of whose electrical load requirements are associated with devices called "power supplies." The Company includes these loads in the Municipal Traffic Signal class for cost of service purposes.

Power supply devices are distributed across the Company's distribution system and operate at a very high load factor. Because of their high load factor (individually and collectively) and the fact that these loads are unmetered, the Company's historical realized return on rate base to serve these loads has been well in excess of the system average rate of return. The Company has partially remedied this problem by placing power supply loads in a more appropriate class. However, the Company's class revenue allocation at proposed rates leaves substantial rate inequities in place for these and a number of other loads across multiple rate classes. This occurs because the Company inconsistently applies its own criteria for spreading the revenue increase and because there are more fundamentally sound criteria that could be used to spread the revenue increase. The result of applying the Company's criteria is a level of rate disparity that cannot be justified on traditional ratemaking principles and should not be approved by this Commission. Thus, the purpose of my testimony is to recommend alternative allocations of the proposed revenue increase that are, in my view, more consistent with proper rate design.

III. IDENTIFICATION OF EXHIBITS

Q. DO YOU SPONSOR ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I sponsor three exhibits with this testimony. Exhibit 1 (PHR-1) is my detailed resume. Exhibit 2 (PHR-2) shows the assignment of proposed distribution revenues resulting from a correct implementation of the Company's rate criteria outlined by Mr. Pfrommer in his testimony. Exhibit 3 (PHR-3) contains my alternative proposal for the assignment of the Company's proposed change in distribution revenue requirements to each customer class using the alternative criteria that I propose.

IV. ORGANIZATION OF TESTIMONY

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four additional sections, labeled V through VIII. The first section, Section V, provides basic rate design criteria that are generally adhered to when developing rates and spreading rate changes that the Commission may order. Section VI discusses the specific rate design criteria to which the Company adhered in developing its proposed rate designs. Section VII presents alternative rate design criteria that promote additional rate equity and still protect against unduly large increases to any class. Finally, my testimony ends with a summary of my conclusions and recommendations.

V. GENERAL RATEMAKING PRINCIPLES

Q. PLEASE DESCRIBE THE MAJOR PRINCIPLES GENERALLY USED TO EVALUATE THE APPROPRIATENESS OF A GIVEN SET OF RATES OR RATE STRUCTURE.

A. The list of potential rate principles, or criteria, can vary, depending upon the specifics of the rate and situation under consideration. However, there exists a set of general principles that are used to evaluate the appropriateness of the utility ratemaking process and the rates that result. While enumerated, categorized or segmented differently by different analysts, these include revenue sufficiency, revenue stability, rate stability, rate predictability, rate efficiency and rate equity. The first two criteria largely protect the utility. The first criterion, revenue sufficiency, argues that the rate structure must allow for the collection of revenues sufficient to equal the utility's revenue requirement. The second criterion, revenue stability, argues that rates in place should be designed so that the revenues collected over time remain stable, at least with respect to changes in costs, and that the revenues do not vary greatly as a result of unforeseen events beyond the utility's control. Rate stability and rate predictability are customer-related criteria. Whenever possible, customers should have stable and predictable rates, both to allow them to budget properly and to make longer term decisions with respect to purchases of or investments in electric-using appliances and equipment. Large increases in rate levels, commonly referred to as "rate shock," should be avoided to the extent possible.

Rate efficiency is a more societal-oriented criterion. Rates should be designed to be economically efficient so that proper consumption decisions are made and no wasteful consumption occurs. Customers should be charged rates equal to the costs resulting from their consumption. Ideally, though rarely in practice, rate efficiency takes into account any economic "externalities" of consumption that might have welfare effects on others such as pollution. Finally, rate equity, or fairness, argues that there should be no undue discrimination among customers in how rates are set. This principle is also referred to as "rate parity." Customers who impose similar costs on the system should be charged in a similar manner and those who impose dissimilar costs should pay different rates reflecting the difference in costs imposed. As a general rule, whenever possible, existing rate disparities among customer classes should be reduced or eliminated.

Q. CAN ANY RATE STRUCTURE SIMULTANEOUSLY SATISFY ALL OF THESE CRITERIA?

A. Not entirely. The development of a sound rate structure will have considered all of these criteria and will have adopted elements of each. However, in the context of traditional rate of return-based regulation, a number of these criteria will compete against one another. For example, revenue sufficiency argues that the rates must generate sufficient revenue to allow the utility to recover its revenue requirement. The principle of rate efficiency, however, argues that, other things being equal, rates should be set so as to equal the costs imposed by customers' consumption decisions. At the time all of these consumption decisions are being made, the costs thereby imposed may be greater than, less than, or (in a very unlikely event) equal to the utility's embedded revenue requirement. This is particularly true if the measurement of costs includes economic externalities. Both principles cannot be fully satisfied simultaneously.

Q. ARE THERE OTHER EXAMPLES OF CONFLICTING RATE CRITERIA?

A. Yes. In particular, there is one situation that almost always arises in rate cases, particularly when, as with this proceeding, significant time has passed since the last change in rates. Simultaneously achieving rate equity while preserving rate stability can be especially difficult. Rates in effect at any time incorporate a number of historical factors, measurements and situations that no longer exist or exist in a significantly different way. That is particularly true in this case in that the Company has not had a rate case in twelve years. Updating the rates for a test year based on current and projected information requires changes to be made to most, if not all, of the rates. If rates are set to equal cost of service, some classes can see significantly greater changes than others. Utilities and regulators usually attempt to balance rate equity and "rate shock" considerations when assigning the change in system revenue requirements to classes.

VI. THE COMPANY'S ALLOCATION PROPOSAL

Q. WHAT CRITERIA HAS THE COMPANY USED IN ALLOCATING ITS PROPOSED RATE INCREASE TO CUSTOMER CLASSES?

A. Mr. Pfrommer lists five criteria that he uses to determine proposed class increases. These are:

1. The increase should result in no rate class having a Rate of Return ("ROR") on distribution rate base of less than 1% or greater than 25%.
2. The overall rate increase to any rate class on a total bill basis should not exceed 1.4 times the overall system average increase on a total bill basis.
3. No rate class should receive a revenue decrease on a total bill basis.
4. Each rate class' rate of return relative to system average should move closer to system average ROR.
5. Retail transmission rates will be set to recover each customer class' transmission-related cost of service.

I will refer to these as Criterion 1, Criterion 2, etc. Mr. Pfrommer argues that these criteria enable the Company to balance its objectives of "reflecting cost of service" and mitigating disparate rate impacts, or in the context of the above discussion, balance the ratemaking goals of rate equity and rate stability.

Q. DO YOU AGREE WITH THE COMPANY'S CRITERIA?

A. No. Although Mr. Pfrommer does address rate equity in his proposal, I do not think the Company's criteria adequately correct for existing rate disparities. There are alternative criteria that promote additional rate equity and still protect against unduly large increases to any class. I introduce these criteria and demonstrate their performance in the following section of my testimony.

Q. NOTWITHSTANDING THIS FACT, DO YOU AGREE WITH MR. PFROMMER'S APPLICATION OF THESE CRITERIA IN THIS CASE?

A. No. The Company has inconsistently applied certain of its criteria and, in cases where the Company's criteria are in conflict, the controlling criterion has not been consistently chosen.

Q. HOW HAS THE COMPANY INCONSISTENTLY APPLIED ITS CRITERIA?

A. As I noted earlier in my testimony, ratemaking objectives often conflict with one another. In specific instances, Mr. Pfrommer was forced to violate three of his rate criteria. Because of low historical rates of return, Mr. Pfrommer had to assign a somewhat greater than 1.4 times the system overall average increase on a total bill basis (Criterion 2) to certain classes in order for them to meet Criterion 1, generating at least a 1% rate or return on distribution rate base. In some cases, Mr. Pfrommer chose to violate Criterion 1 for four other classes, generating no more than a 25% rate of return on distribution assets, presumably in order to preserve Criterion 3, that no class should see a revenue decrease on a total bill basis. And yet, he does propose a revenue decrease for at least one lighting class.

This is not entirely unwarranted. As I have noted, certain ratemaking objectives frequently conflict with one another. It is always difficult and usually impossible to satisfy all rate objectives simultaneously. When objectives do conflict, professional judgment must be applied to determine how to assign changes in revenue and how to design rates for specific classes so that the entirety of a utility's ratemaking goals are best accomplished. I believe that the Company tried to do that in this case. When deciding which objectives to pursue, however, care must be taken to ensure consistency across rate classes. In this case, I believe that the Company has been inconsistent as to how it has decided to apply certain of the criteria to different classes. For example, Mr. Pfrommer admits that he had to violate Criterion 3 in order to get certain classes up to a 1% return on distribution rate base. These classes are Residential Service Heating (RH) and Residential Service Add-On Heat Pump (RA). What he doesn't discuss is that he also violates the same criterion in assigning increased revenues to the Street Lighting Highways (SH) class.[1] This class is assigned an increase approximately 2.5 times the system average on a total bill basis. Unlike with the RH and RA classes, however, there was no need to violate Criterion 2 as class revenues at present rates are

[1] Mr. Pfrommer avoids the discussion by indicating that he combined all lighting classes together for purposes of revenue assignment. However, as I will discuss, he makes specific, and different, decisions with respect to revenue allocation on a lighting class-by-class basis.

already sufficient to generate a greater than 1% return on requested distribution rate base.

Similarly, Mr. Pfrommer has been inconsistent in how he has treated different classes that fall outside of the 25% upper end of the "acceptable" range for rate of return on distribution rate base. Four classes fall above this number at present rates: Street Lighting Energy (SE), Unmetered Service (UMS), Private Area Lighting (PAL) and High Voltage Power Service (HVPS). Each class has been treated differently in the proposed revenue allocation. HVPS has a rate of return at present rates on distribution rate base of 47.55%. The Company has proposed a 7.3% decrease in distribution rates to bring the HVPS class target rate of return on distribution down to approximately the 25% target. It can do so without violating Criterion 3, that no class should see a decrease on a total bill basis, because HPVS has been given a proposed transmission rate increase larger than the reduction in its proposed distribution rate. The UMS class has a roughly equivalent distribution return at present rates of 45.51%. Unlike HVPS, however, the Company has proposed no distribution rate decrease for UMS, presumably so that it does not violate Criterion 3. The proposed distribution rate of return at proposed rates for UMS is 29.84%, violating Criteria 1. The Company's proposal does not even take into account the fact that it is proposing to increase UMS transmission rates by roughly 24%. Thus, the Company could have at least built in a distribution decrease equivalent to the transmission increase and still not violated Criterion 3. By not doing so, the Company is actually proposing an overall bill increase for this class, despite the fact that UMS customers will generate a distribution rate of return in excess of 3 times the system average.

Q. DOES THE COMPANY TREAT THE OTHER TWO LIGHTING CLASSES WITH DISTRIBUTION RATES OF RETURN ABOVE 25% SIMILAR TO UMS WITH RESPECT TO ITS FIVE CRITERIA?

A. No. The SE class, though, has been treated most similarly to UMS. A small distribution increase has been assigned to offset a decrease in transmission rates, again to satisfy Criterion 3. The only difference is that changes to transmission and distribution revenues are offset so that the class is left with no change in rates on a total bill basis. The UMS class is left with an increase, however, since the increase in transmission revenue requirements was not offset by a corresponding decrease in assigned distribution revenues.

Interestingly enough, and despite the Company using Criterion 3 as controlling in proposing UMS revenues, the PAL class has been given a decrease on an overall bill basis, in violation of Criterion 3 despite the Company's use of Criterion 3 as the controlling criterion in proposing UMS and SE revenues. Proposed distribution revenues for the PAL class are approximately 36% lower than revenues at present rates and proposed transmission revenues have been eliminated (admittedly, from a very small level). Proposed rates represent over a 25% reduction in rates on a total bill basis. This leaves the PAL class with a target rate of return of just over 37%. Thus, unlike with UMS and SE, the Company has clearly chosen to violate both Criterions 1 and 3.

Q. WHY DO YOU SAY THAT THE COMPANY HAS ALSO BEEN INCONSISTENT IN HOW IT RANKS ITS CRITERIA?

A. Mr. Pfrommer provides no ordinal ranking of the relative importance of his five criteria. Nonetheless, from the discussion in his testimony, it is clear that this first consideration was to establish a range of class rates of return that he feels is reasonable. He determines that the reasonable range is the 1% to 25% contained in Criterion 1. He then considers whether moving classes into this range will result in changes in rates that are too large either in the upward direction (Criterion 2) or the downward direction (Criterion 3). In that sense, Criteria 2 and 3 are very closely related in an inverse way. They are both designed with the purpose of limiting the magnitudes of the changes in rates assigned to customer classes.

If a conflict results, he then makes a decision as to which of his criteria he must violate. It is interesting that when a customer class rate of return falls below the range specified in Criterion 1, he chooses to violate Criterion 2. In other words, he has implicitly ranked Criterion 1 as being *more* important than Criterion 2 when equity considerations argue that rates should rise. On the other hand, when the mirror image problem arises, i.e. that when a customer class rate of return exceeds the maximum of Criterion 1, he doesn't choose to violate Criterion 3. Rather he chooses to violate Criterion 1 instead. Thus, he has implicitly ranked Criterion 1 as *less* important than Criterion 3 when similar equity considerations argue that rates should fall. I believe this application to be inconsistent, and it serves to perpetuate large class rate inequities unnecessarily.

Q. WHAT WOULD BE THE COMPANY'S PROPOSED DISTRIBUTION REVENUES BY CLASS IF IT CORRECTED FOR THE INCONSISTENCIES YOU HAVE IDENTIFIED?

A. Exhibit 2 (PHR-2) shows the revenue allocation that results from correcting for the inconsistencies in how the Company applied its criteria. Criterion 1 has been preserved in all cases such that every customer has a targeted distribution rate of return between 1% and 25%. Because the classes that have rates of return in excess of 25% are all relatively small, the total amount of the distribution revenue requirement that has been re-assigned from the Company's proposal is only $669,000. The result is a slightly more equitable assignment that does not result in excessively large increases to any class.

VII. ALTERNATIVE RATE CRITERIA

Q. ARE YOU PROPOSING THAT THE COMMISSION ADOPT THE RATE CHANGE BY CUSTOMER CLASS SHOWN ON EXHIBIT 2 (PHR-2)?

A. No. As I stated earlier, I do not think the Company's criteria adequately address existing rate disparities and I therefore propose alternative criteria that I believe promote additional rate equity while still protecting against unduly large increases to any class.

Q. WHAT SPECIFIC CHANGES WOULD YOU MAKE TO THE COMPANY'S CRITERIA?

A. Lest I appear too critical of the Company's efforts, it is important to recognize that choosing the right criteria by which to balance the concerns of rate equity and rate stability is inherently a somewhat arbitrary process, and depends on the unique circumstances of a particular case. For example, no two observers will have exactly the same definition of how much of an increase is too large, or results in "rate shock," for example. Similarly, individuals will disagree as to how much rate inequity is "too much." Nonetheless, I think some of the Company's criteria are overly arbitrary and ill suited to accomplish their stated intent. For example, the Company's Criterion 2 argues that the overall rate increase to any rate class on a total bill basis should not exceed 1.4 times the overall system average increase on a total bill basis. Presumably, this criterion is designed to prevent unacceptable rate increases to individual customer classes. If so, however, it would have been better to design such a criterion as a maximum percentage rate increase, not one relative to the average system increase. For example, the Company could have limited the increase to any particular class to 35% regardless of the overall system increase, or some other level it deemed appropriate. Rate shock results from the size of an increase faced by a particular customer, not from the relative size of an increase to the system average. A particular rate class can absorb a very large relative increase if the overall system average increase is small. Conversely, if the overall system average increase is large, that same class could absorb only a small deviation from the system average. Thus, without knowing the size of the system increase that will be approved, it is impossible to determine what relative increase will be too large. Furthermore, the particular value selected by the Company, 1.4 times the system average, appears not to be an *a priori* determination based on professional judgment of the upper limit on an acceptable increase. Rather, it not so coincidentally equals the increase assigned to the Residential Service (RS) class and thus appears to be a retroactively determined amount to justify the increase proposed for RS customers.

Q. WHAT OTHER CHANGES WOULD YOU MAKE TO THE COMPANY'S CRITERIA?

A. Criterion 1, which sets the target class rates of return between 1% and 25%, is too wide a range. Recognizing that the Company hasn't adjusted retail rates in quite some time, this still results in significant rate inequities among classes. Classes that have been paying substantially in excess of the costs to serve them over the last 12 to 18 years are effectively being asked to continue to do so, albeit to a slightly smaller extent. I recommend that class target revenues be set using a range of class rates of return relative to the system average return, e.g., 75% to 150% of the system average. Thus, if the system average allowed rate of return were 10%, target class rates of return would fall between 7.5% and 15%. The selection of the most appropriate range is never obvious, and depends on the situation at hand. In this case, I would argue that a broader range be implemented because existing wide rate disparities might otherwise result in overly large rate increases to one or more classes. For this proceeding, I therefore recommend a range of 50%-200% around the system average. At the Company proposed rate of return of 9.08%, this range would result in targeted class rates of return from 4.54% to 18.16%. In future cases, the range can be progressively narrowed.

Q. WOULDN'T EVEN THE LOW END OF THIS RANGE RESULT IN UNACCEPTABLY LARGE INCREASES FOR RH AND RA CUSTOMERS?

A. Yes. In this case, I agree with the Company that the low end of its range of appropriate class rates of return, 1%, is about as high as one can go for the RH class, since even this very low rate of return would result in overall bill increase of 37.5% to the Residential Heating class. To treat all other customer classes consistently, I would therefore modify the Company's Criterion 2 to limit all increases to 37.5% on a total bill basis.

Q. **DO YOU HAVE ANY OTHER SUGGESTED CHANGES TO THE COMPANY'S CRITERIA?**

A. Yes. I have one other proposed change. I would eliminate Criterion 3. It seems to accomplish none of the generally accepted ratemaking objectives I discuss earlier in my testimony, and only serves to preserve unacceptably large rate inequities contained in the Company's existing rate structure. Mr. Pfrommer makes the curious statement that Criterion 3 "*promotes inter-class equity by ensuring that no rate class receives a* revenue decrease at the same time that other rate classes are receiving significant rate increases." Yet rate equity is maximized when all classes pay revenues equal to the cost to serve them. Inequities result when rate classes pay either more or less than the cost to serve. The greater the difference between revenues and cost of service, the greater the inequity for any given class. Any criterion that prevents movement towards more equalized class rates of return actually serves to lessen inter-class equity, not promote it. Not allowing a class to receive a decrease only hurts those customer classes who are most disadvantaged in the first place. Those customers who have provided the greatest subsidies to other ratepayers over the historic period are the only ones penalized, and ironically penalized for having provided those subsidies in the first place. It may be politically expedient to not allow a class to have a rate decrease while others are getting increases, but it certainly does not promote rate equity.

Q. DID YOU MAKE CHANGES TO THE COMPANY'S CRITERIA 4 AND 5?

A. No. I believe these two rate criteria are appropriate as structured.

Q. PLEASE SUMMARIZE THE CRITERIA YOU WOULD RECOMMEND BE EMPLOYED TO ASSIGN THE OVERALL REVENUE INCREASE APPROVED BY THIS COMMISSION.

A. I propose the following criteria be used in this case:

1. The increase should result in no rate class having a Rate of Return ("ROR") on distribution rate base of less than 50 percent or greater than 200 percent of the system average.
2. The overall rate increase to any rate class on a total bill basis should not exceed 37.5 percent. This criterion shall apply in the event of a conflict between this criterion and the first.
3. Each rate class' rate of return relative to system average should move closer to system average ROR or "unity," i.e., measured as class distribution ROR divided by system average distribution ROR.
4. Retail transmission rates will be set to recover each customer class' transmission-related cost of service.

A schedule demonstrating the effect of applying these criteria to the Company's proposed revenue increase is provided as Exhibit 3 (PHR-3). That exhibit shows distribution rates of return range from 1% for the RH class to 18.08% for five classes including Municipal Traffic Signals. This revenue assignment results in considerably greater rate equity than does the Company's proposed assignment without resulting in significantly greater increases for other classes.

VIII. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my opinion, the Company's criteria to allocate the proposed rate increase among customer classes do not adequately address existing rate disparities. There are alternative criteria that promote additional rate equity and still protect against unduly large increases to any class. Furthermore, the Company has inconsistently applied certain of its own criteria and, in cases where the Company's criteria are in conflict, the controlling criterion has not been consistently chosen.

Q. BASED ON THIS TESTIMONY, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I respectfully recommend that the Commission adopt a revenue distribution in this case consistent with the criteria I have developed and applied in Exhibit 3 (PHR-3). In the event that the Commission determines that the Company's criteria are more appropriate in this case, I recommend that the Company be directed to apply these criteria consistently as shown in Exhibit 2 (PHR-2).

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes, it does.

Respectfully submitted,

COMCAST OF CALIFORNIA/PENNSYLVANIA/
UTAH/WASHINGTON, INC.

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September 14, 2006

EXHIBIT 1 (PHR-1)

PAUL H. RAAB

Mr. Raab's consulting focus is on the regulated public utility industry. His experience includes mathematical and economic analyses and system development and his areas of expertise include regulatory change management, load forecasting, supply-side and demand-side planning, management audits, mergers and acquisitions, costing and rate design, and depreciation and life analysis.

PROFESSIONAL EXPERIENCE

Mr. Raab has directed or has had a key role in numerous engagements in the areas listed above. Representative clients are provided for each of these areas in the subsections below.

Regulatory Change Management. Mr. Raab has recently been assisting both electric and natural gas utilities as they prepare to operate in an environment that is significantly different from the one they operate in today. This work has involved the development of unbundled cost of service studies; the development of strategies that will allow companies to prosper in a restructured industry; retail access program development, implementation, and evaluation; and the development of innovative ratemaking approaches to accompany changes in the regulatory structure. Representative clients for whom he has performed such work include:

- Kansas Corporation Commission
- Atmos Energy Corporation
- Electric Cooperatives' Association
- Central Louisiana Electric Company
- Washington Gas
- Western Resources
- Kansas Gas Service
- Mid Continent Market Center.

Load Forecasting. Mr. Raab has broad experience in the review and development of forecasts of sales forecasts for electric and natural gas utilities. This work has also included the development of elasticity of demand measures that have been used for attrition adjustments and revenue requirement reconciliations. Representative clients for whom he has performed such work include:

- Washington Gas Energy Services
- Central Louisiana Electric Company
- Washington Gas
- Saskatchewan Public Utilities Review Commission

- o Union Gas Limited
- o Nova Scotia Power Corporation
- o Cajun Electric Power Cooperative
- o Cincinnati Gas & Electric
- o Commonwealth Edison Company
- o Cleveland Electric Illuminating
- o Public Service of Indiana
- o Atlantic City Electric Company
- o Detroit Edison Company
- o Sierra Pacific Power
- o Connecticut Natural Gas Corporation
- o Appalachian Power Company
- o Missouri Public Service Company
- o Empire District Electric Company
- o Public Service Company of Oklahoma
- o Wisconsin Electric Power Company
- o Northern States Power Company
- o Iowa State Commerce Commission
- o Missouri Public Service Commission.

Supply Side Planning. Mr. Raab has assisted clients to determine the most appropriate supply-side resources to meet future demands. This assistance has included the determination of optimal sizes and types of capacity to install, determination of production costs including and excluding the resource, and an assessment of system reliability changes as a result of different resource additions. Much of this work for the following clients has been done in conjunction with litigation:

- o Washington Gas
- o Soyland Electric Cooperative
- o Houston Lighting and Power
- o City of Farmington, New Mexico
- o Big Rivers Electric Cooperative
- o City of Redding, California
- o Brown & Root
- o Kentucky Joint Committee on Electric Power Planning Coordination
- o Sierra Pacific Power.

Demand Side Planning. Demand Side Planning involves the forecasting of future demands; the design, development, implementation, and evaluation of demand side management programs; the determination of future supply side costs; and the integration of cost effective demand side management programs into an Integrated Least Cost Resource Plan. Mr. Raab has performed such work for the following clients:

- o Washington Gas Light Company

- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- Montana-Dakota Utilities.

Management Audits. Mr. Raab has been involved in a number of management audits. Consistent with his other experience, the focus of his efforts has been in the areas of load forecasting, demand- and supply-side planning, integrated resource planning, sales and marketing, and rates. Representative commission/utility clients are as follows:

- Public Utilities Commission of Ohio/East Ohio Gas
- Kentucky Public Service Commission/Louisville Gas & Electric
- New Hampshire Public Service Commission/Public Service Company of New Hampshire
- New Mexico Public Service Commission/Public Service of New Mexico
- New York Public Service Commission/New York State Electric & Gas
- Missouri Public Service Commission/Laclede Gas Company
- New Jersey Board of Public Utilities/Jersey Central Power & Light
- New Jersey Board of Public Utilities/New Jersey Natural Gas
- Pennsylvania Public Utilities Commission/ Pennsylvania Power & Light
- California Public Utilities Commission/San Diego Gas & Electric Company.

Mergers and Acquisitions. Mr. Raab has been involved in a number of merger and acquisition studies throughout his career. Many of these were conducted as confidential studies and cannot be listed. Those in which his involvement was publicly known are:

- ONEOK, Inc./Southwest Gas Corporation
- Western Resources
- Constellation.

Costing and Rate Design Analysis. Mr. Raab has prepared generic rate design studies for the National Governor's Conference, the Electricity Consumer's Resource Council, the Tennessee Valley Industrial Committee, the State Electricity Commission of Western Australia, and the State Electricity Commission of Victoria. These generic studies addressed advantages and disadvantages of alternative costing approaches in the electric utility industry; the strengths and weaknesses of commonly encountered costing methodologies; future tariff policies to promote equity, efficiency, and fairness criteria; and the advisability of changing tariff policies. Mr. Raab has performed specific costing and rate design studies for the following companies:

- Aquila
- Oklahoma Natural Gas
- Semco Energy Gas Company
- Laclede Gas
- Western Resources
- Kansas Gas Service Company
- Central Louisiana Electric Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- KPL Gas Service Company
- Allegheny Power Systems
- Northern States Power
- Interstate Power Company
- Iowa-Illinois Gas & Electric Company
- Arkansas Power and Light
- Iowa Power & Light
- Iowa Public Service Company
- Southern California Edison
- Pacific Gas & Electric
- New York State Electric & Gas
- Middle South Utilities
- Missouri Public Service Company
- Empire District Electric Company
- Sierra Pacific Power
- Commonwealth Edison Company
- South Carolina Electric & Gas
- State Electricity Commission of Western Australia
- State Electricity Commission of Victoria, Australia
- Public Service Company of New Mexico
- Tennessee Valley Authority.

Depreciation and Life Analysis. Mr. Raab has extensive experience in depreciation and life analysis studies for the electric, gas, rail, and telephone industries and has taught a course on depreciation at George Washington University, Washington, DC. Representative clients in this area include:

- Champaign Telephone Company
- Plains Generation & Transmission Cooperative
- CSX Corporation (Includes work for Seaboard Coast Line, Louisville & Nashville, Baltimore & Ohio, Chesapeake & Ohio, and Western Maryland Railroads)
- Lea County Electric Cooperative, Inc.
- North Carolina Electric Membership Cooperative

- Alberta Gas Trunk Lines (NOVA)
- Federal Communications Commission.

TESTIMONY

The following table summarizes Mr. Raab's testimony experience.

Jurisdiction	Docket Number	Subject
District of Columbia	834	Demand Side Planning
	905	Costing/Rate Design
	917	Costing/Rate Design
	921	Demand Side Planning
	922	Rate Design
	934	Rate Design
	989	Rate Design
	1016	Rate Design
Georgia	18300-U	Costing/Rate Design
Indiana	36818	Capacity Planning
Kansas	174,155-U	Retail Competition
	176,716-U	Costing/Rate Design
	98-KGSG-822-TAR	Rate Design
	99-KGSG-705-GIG	Restructuring
	01-KGSG-229-TAR	Rate Design
	02-KGSG-018-TAR	Rate Design
	02-WSRE-301-RTS	Cost of Service
	03-KGSG-602-RTS	Cost of Service/Rate Design
	03-AQLG-1076-TAR	Rate Design
Kentucky	9613	Capacity Planning
	97-083	Management Audit
Louisiana	U-21453	Restructuring/Market Power
Maryland	8251	Costing/Rate Design
	8259	Demand Side Planning
	8315	Costing/Rate Design
	8720	Demand Side Planning
	8791	Costing/Rate Design
	8920	Costing/Rate Design
	8959	Costing/Rate Design

Jurisdiction	Docket Number	Subject
Michigan	U-6949 U-13575	Load Forecasting Costing/Rate Design
Missouri	GR-2002-356	Rate Design
Nebraska	NG-0001, NG-0002, NG-0003	Rate Design
Nevada	81-660	Load Forecasting
New Jersey	OAL# PUC 1876-82 BPU# 822-0116	Load Forecasting
New Mexico	2087	Capacity Planning
New York	27546	Costing/Rate Design
Ohio	81-1378-EL-AIR	Load Forecasting
Oklahoma	27068	Load Forecasting
Tennessee	PURPA Hearings	Costing/Rate Design
US Tax Court	4870 4875	Life Analysis Life Analysis
Virginia	PUE900013 PUE920041 PUE940030 PUE940031 PUE950131 PUE-2002-00364	Demand Side Planning Costing/Rate Design Costing/Rate Design Costing/Rate Design Capacity Planning Costing/Rate Design
West Virginia	79-140-E-42T 90-046-E-PC	Capacity Planning Demand Side Planning
Wisconsin	05-EP-2	Capacity Planning

In addition, Mr. Raab has presented expert testimony before the Michigan House Economic Development and Energy Committee and the Province of Saskatchewan. He is a member of the Advisory Board of the Expert Evidence Report, published by The Bureau of National Affairs, Inc.

EDUCATION

Mr. Raab holds a B.A. (with high distinction) in Economics from Rutgers University and an M.A. from SUNY at Binghamton with a concentration in Econometrics. While attending Rutgers, he studied as a Henry Rutgers Scholar.

PUBLICATIONS AND PRESENTATIONS

Mr. Raab has published in a number of professional journals and spoken at a number of industry conferences. His publications/ presentations include:

- "Responses to Arrearage Problems From High Natural Gas Bills," American Gas Association Rate and Regulatory Issues Seminar, Phoenix, AZ, April 8, 2004.

- "Factors Influencing Cooperative Power Supply," National Rural Utilities Cooperative Finance Corporation Independent Borrower's Conference, Boston, MA, July 3, 1997.

- "Current Status of LDC Unbundling," American Gas Association Unbundling Conference: Regulatory and Competitive Issues, Arlington, VA, June 19, 1997.

- "Balancing, Capacity Assignment, and Stranded Costs," American Gas Association Rate and Strategic Planning Committee Spring Meeting, Phoenix, AZ, March 26, 1997.

- "Gas Industry Restructuring and Changes: The Relationship of Economics and Marketing" (with Jed Smith), National Association of Business Economists, 38th Annual Meeting, Boston, MA September 10, 1996.

- "Improving Corporate Performance By Better Forecasting," 1996 Peak Day Demand and Supply Planning Seminar, San Francisco, CA, April 11, 1996.

- "Natural Gas Price Elasticity Estimation," AGA Forecasting Review, Vol. 6, No. 1, November 1995.

- "Assessing Price Competitiveness," Competitive Analysis & Benchmarking for Power Companies, Washington, DC, November 13, 1995.

- "Avoided Cost Concepts and Management Considerations," Workshop on Avoided Costs in a Post 636 Gas Industry: Is It Time to Unbundle Avoided Cost? Sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, Milwaukee, WI, June 29, 1994.

- "Estimating Implied Long- and Short-Run Price Elasticities of Natural Gas Consumption," Atlantic Economic Conference, Philadelphia, PA, October 10, 1993.

- "Program Evaluation and Marginal Cost," The Natural Gas Least Cost Planning Conference, Washington, DC, April 7, 1992.

- "The New Environmentalism & Least Cost Planning," Institute for Environmental Negotiation, University of Virginia, May 15, 1991.

- "Development of Conditional Demand Estimates of Gas Appliances," AGA Forecasting Review, Vol. 1, No. 1, October 1988.

- "The Feasibility Study: Forecasting and Sensitivities," Municipal Wastewater Treatment Facilities, The Energy Bureau, Inc., November 18, 1985.

- "The Development of a Gas Sales End-Use Forecasting Model," Third International Forecasting Symposium, The International Institute of Forecasting, July 1984.

- "New Forecasting Guidelines for REC's - A Seminar," (Chairman), Kansas City, Missouri, June 1984.

- "A Method and Application of Estimating Long Run Marginal Cost for an Electric Utility," Advances in Microeconomics, Volume II, 1983.

- "Forecasting Under Public Scrutiny," Forecasting Energy and Demand Requirements, University of Wisconsin - Extension, October 25, 1982.

- "Forecasting Public Utilities," The Journal of Business Forecasting, Vol. 1, No. 4, Summer, 1982.

- "Are Utilities Underforecasting," Electric Ratemaking, Vol. 1. No. 1, February, 1982.

- "A Polynomial Spline Function Technique for Defining and Forecasting Electric Utility Load Duration Curves," First International Forecasting Symposium, Montreal, Canada, May, 1981.

- "Time-of-Use Rates and Marginal Costs," ELCON Legal Seminar, *March 20, I980.*

- "The Ernst & Whinney Forecasting Model," Forecasting Energy & Demand Requirements, University of Wisconsin - Extension, October 8, I979.

- "Marginal Cost in Electric Utilities--A Multi-Technology Multi-Period Analysis" (with Frederick McCoy), ORSA/Tims Joint National Meeting, Los Angeles, California, November 13-15, 1978.

EXHIBIT 2 (PHR-2)

Distribution Rate of Return at Proposed Rates

Classes Limited to 25% ROR

Line No.	(A)	System (B)	Residential (C)	Residential Heating (D)	Residential Add-On Heat Pump (E)	General Small / General Medium (F)	General Medium Heating (G)	General Large (H)	General Large Heating (I)	Large (J)	High Voltage Power Service (K)	Architectural Lighting (L)	Street Lighting Energy (M)	Street Lighting Municipal (N)	Street Lighting Highway (O)	Municipal Traffic Signals (P)	Private Area Lighting (Q)
1	Tariff Revenue at Proposed Rates	423,625	204,520	13,602	1,364	89,421	7,115	66,533	8,826	21,025	393	1	939	9,159	123	520	84
2	Wholesale, Other	14,282	8,259	670	68	2,315	216	1,707	281	553	25	-	35	133	1	15	3
3	Total Distribution Revenue	437,907	212,779	14,272	1,432	91,736	7,331	68,241	9,107	21,578	418	1	974	9,292	124	535	87
4																	
5	Operating Expenses	166,290	106,837	8,785	936	23,259	2,239	12,773	2,389	4,122	228	1	152	2,410	35	111	19
6	Depreciation	66,400	35,405	3,320	295	11,715	1,263	8,503	1,627	2,751	34	1	89	1,320	20	48	8
7	General Taxes	7,997	4,639	390	37	1,337	136	847	161	274	9	-	9	149	2	6	1
8	Gross Receipts Tax	25,237	12,267	824	83	5,288	423	3,934	525	1,244	24	0	56	528	7	30	5
9	Total Expenses	265,924	161,148	13,319	1,350	41,600	4,055	28,057	4,702	8,391	295	2	305	4,407	64	195	33
10																	
11	Return before Income Taxes	171,983	51,632	953	82	50,136	3,276	42,183	4,404	13,187	123	(1)	669	4,885	60	340	54
12	Income Tax	60,089	18,040	333	29	17,517	1,145	14,738	1,539	4,607	43	(0)	234	1,707	21	119	19
13	After-Tax Return	111,894	33,592	620	54	32,619	2,131	27,445	2,866	8,579	80	(1)	435	3,178	39	221	35
14																	
15	Distribution Rate Base	1,232,857	630,118	62,030	5,369	222,791	24,641	170,729	33,138	55,307	321	16	1,740	25,244	388	885	140
16																	
17	After-Tax ROR	9.08%	5.33%	1.00%	1.00%	14.64%	8.65%	16.08%	8.65%	15.51%	24.99%	-4.29%	25.00%	12.59%	10.09%	25.00%	25.00%
18																	
19	Relative Rate of Return	100.0%	58.7%	11.0%	11.0%	161.3%	95.3%	177.1%	95.3%	170.9%	275.4%	-47.3%	275.4%	138.7%	111.1%	275.4%	275.4%

EXHIBIT 3 (PHR-3)

Distribution Rate of Return at Proposed Rates
Classes Limited to 200% of System Average ROR

Line No.	(A)	System (B)	Residential (C)	*Residential Heating* (D)	Residential Add-On Heat Pump (E)	General Small / General Medium (F)	General Medium Heating (G)	General Large (H)	General Large Heating (I)	Large (J)	High Voltage Power Service (K)	Architectural Lighting (L)	Street Lighting Energy (M)	Street Lighting Municipal (N)	Street Lighting Highway (O)	Municipal Traffic Signals (P)	Private Area Lighting (Q)
1	Tariff Revenue at Proposed Rates	423,625	204,692	13,602	1,367	89,496	7,121	66,589	8,833	21,042	358	1	745	9,167	123	422	68
2	Wholesale, Other	14,282	8,259	670	68	2,315	216	1,707	281	553	25	-	35	133	1	15	3
3	Total Distribution Revenue	437,907	212,951	14,272	1,435	91,811	7,337	68,296	9,114	21,595	383	1	780	9,300	124	437	71
4																	
5	Operating Expenses	166,290	108,837	8,785	935	23,259	2,233	12,773	2,389	4,122	228	1	152	2,410	35	111	19
6	Depreciation	66,400	35,405	3,320	295	11,715	1,263	8,503	1,627	2,751	34	1	89	1,320	20	48	8
7	General Taxes	7,997	4,639	390	37	1,337	136	847	161	274	9	-	9	149	2	6	1
8	Gross Receipts Tax	25,237	12,276	825	83	5,293	423	3,937	525	1,245	22	0	44	528	7	25	4
9	Total Expenses	265,924	161,157	13,320	1,350	41,604	4,056	26,061	4,702	8,392	293	2	294	4,407	64	190	32
10																	
11	Return before Income Taxes	171,983	51,794	952	86	50,207	3,282	42,236	4,411	13,203	90	(1)	485	4,892	60	247	39
12	Income Tax	60,089	18,096	333	30	17,542	1,147	14,757	1,541	4,613	31	(0)	170	1,709	21	86	14
13	After-Tax Return	111,894	33,697	619	56	32,665	2,135	27,479	2,870	8,590	58	(1)	316	3,183	39	161	25
14																	
15	Distribution Rate Base	1,232,857	630,118	62,030	5,369	222,791	24,641	170,729	33,138	55,307	321	16	1,740	25,244	388	885	140
16																	
17	After-Tax ROR	9.08%	5.35%	1.00%	1.04%	14.66%	8.66%	16.10%	8.66%	15.53%	18.14%	-4.29%	18.15%	12.61%	10.10%	18.15%	18.15%
18																	
19	Relative Rate of Return	100.0%	58.9%	11.0%	11.4%	161.5%	95.5%	177.3%	95.4%	171.1%	199.9%	-47.3%	200.0%	138.9%	111.3%	200.0%	200.0%

State of Pennsylvania

Before the Public Utility Commission

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. 00061346**
Duquesne Light Company	)	

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Citizens for Pennsylvania's Future
Statement 1

Direct Testimony of John Hanger

July 7, 2006

Q: Please state your name and business address.

A: My name is John Hanger. My business address is 610 North Third Street, Harrisburg, PA 17101.

Q: By Whom Are You Employed And In What Capacity?

A: I have been President and Chief Executive Officer of Citizens for Pennsylvania's Future ("PennFuture") since it was founded in 1998.

Q: Please describe your education and professional experience.

A: I am a 1979 graduate of Duke University and a 1984 graduate of the University of Pennsylvania School of Law. From April 1993 to June 1998, I was a Commissioner with the Pennsylvania Public Utility Commission. During that time, I served on the Electricity Committee, the Consumer Affairs Committee, and the Committee on Energy Resources and the Environment of the National Association of Regulatory Utility Commissioners (NARUC). Prior to becoming Commissioner, I was legal counsel to Pennsylvania Public Utility Commissioner Joseph Rhodes from 1988 to 1993. From 1984 to 1988 I worked at Community Legal Services, Inc. of Philadelphia, serving as Public Advocate representing 500,000 municipal customers of the City of Philadelphia's municipal gas, water, and sewer utilities.

Q: What are your responsibilities as President and CEO of Pennfuture?

A: I am responsible for all aspects of the work of the organization, which has a staff of 16 at offices in Philadelphia, West Chester, Pittsburgh and Harrisburg.

PennFuture engages in a wide range of activities, through litigation, public education, public policy and other means to improve the environment and economy of Pennsylvania.

A major objective of PennFuture is to promote efficient restructured electricity markets and to integrate cleaner electricity solutions into the electricity system. I work on these issues on a daily basis. I am frequently asked by the press to comment on such issues. I have been regularly asked by policymakers for information and recommendations on electricity policy. I have testified before the United States Congress and state legislatures. I have authored numerous articles, written leading regulatory decisions and lectured to diverse audiences.

Q: What has happened to residential electricity prices in the Duquesne Light service territory since passage in 1996 of the Electricity Generation Customer Choice and Competition Act?

A: Put simply, residential electric rates are substantially lower. In fact, the results have been extraordinary, as I will discuss in detail below.

To put into context what has happened to residential electricity prices in the Duquesne Light Company service territory since 1996, it is useful to understand that prices in general have increased for a variety of services during this time period.

Since 1996, the price has increased for cable television by 56 percent; the price for water service from some Pennsylvania water utilities prices has increased by approximately 100 percent; the price of college tuition increased by 69.7 percent; and the price of prescription medicines has increased by 43.6 percent. While prices have increased, it is also worth noting that since 1996 nominal dollar incomes have increased for most Pennsylvanians. For example, Social Security payments have increased by 37.5 percent.

In 1996 Duquesne Light's residential customers were paying among the highest electric rates in the country and the second highest in Pennsylvania. Indeed, the average price for electricity in Pennsylvania was approximately 15 percent above the national average at that time. In 1996, nearly 40 percent of Pennsylvania's residential customers were paying as much as 50 percent more than the national average for electricity, with only a smaller number paying less than the national average.

When the PUC unbundled rates in 1996, residential customers of the six largest electric utilities were paying the following prices just for generation and transmission service:

COMPANY	1996 Rates	1996 Rates in 2006 Dollars
Duquesne	8.75¢	11.20¢
PECO	8.65¢	11.07¢
PPL	6.26¢	8.01¢
MetEd	5.70¢	7.30¢
Penelec	5.40¢	6.91¢
Allegheny	5.30¢	6.78¢

(all rates expressed in cents per kilowatt-hours)

Comparing the above 1996 rates in both nominal and constant dollars to the 2006 competitive residential price of 6.6 cents per kilowatt-hour offered by Dominion in Duquesne Light service territory and the Duquesne Light residential provider of last resort rate, that is only slightly higher, indicates that both are lower in constant dollars than the historic regulated rates in many parts of the Commonwealth.

Q: **How do the current electric prices for residential consumers in the Duquesne Light service territory compare to rates in 1996?**

A: Duquesne Light residential electric prices are substantially lower now in the Duquesne Light service territory in constant dollars, and even in nominal dollars, than they were in 1996. Residential customers have benefited enormously from restructuring, with savings for them averaging $170 per year for non-electric heating customers and $440 per year for electric heating customers. The PUC, the

Office of Consumer Advocate, Duquesne Light, PJM Interconnection and competitive suppliers like Dominion all deserve credit for this remarkable success.

In May 2006, Dominion offered residential customers a price of 6.6 cents per kilowatt-hour, and Duquesne Light's provider of last resort price was only slightly higher. This price compares to the 8.75 cents per kilowatt-hour residential customers paid to Duquesne Light in 1996.

In the Duquesne Light territory, today's residential prices are about 25 percent lower in nominal dollars and 45 percent lower in constant dollars. In fact, the current Dominion residential competitive price is lower in constant dollars than any of Pennsylvania's utilities' unbundled 1996 residential generation rate.

Q: What steps can Duquesne Light take to ensure that rates remain low for its customers?

A: Duquesne Light should increase the supply of electricity, especially new generation that does not burn fossil fuels, and boost energy conservation to reduce demand from what it would otherwise be. Boosting supply, reducing demand - especially peak demand - and diversifying the fuels used to make electricity will exert a downward pressure on prices.

Marginal increases in supply, especially supply that does not rely on currently expensive and nearly always volatile fossil fuel prices, and marginal decreases in demand, especially peak demand, can reduce prices. PJM has calculated that small reductions in peak demand can lead to much larger reductions in peak price. For example, PJM has estimated that a one per-cent reduction in peak demand can lead to a 10 percent reduction in peak price.

Q: What is renewable energy?

A: For purposes of this testimony, I consider renewable energy to be Tier I resources identified in the Alternative Energy Portfolio Standard (AEPS) law. These include wind, solar photovoltaic, incremental hydro power, biomass and biogas, including that derived from methane gas produced from the digestion of animal manure.

Q: Can you summarize the benefits of renewable energy to consumers of electricity?

A: Renewable energy technologies offer substantial benefits to the electricity consumer. Renewable energy is produced in a manner that benefits the environment, helps protect public health, and reduces the reliance on coal, natural gas and oil. Renewable energy helps diversify how electricity is made, reducing reliance on fossil fuels and their volatile prices, which benefits electricity consumers. This is especially true when one consider that prices for natural gas, coal and oil all have sharply increased in the last five years and that natural gas plants have become more frequently the plants that are on the margin. Renewable energy uses fuel that is domestic and not subject to foreign fuel security issues. In the case of wind power, solar, methane capture, and hydroelectric power, renewable energy technologies produce electricity with a fuel that has virtually no cost. This new technology sector also provides new jobs and economic growth to the region in which it is located.

The Pennsylvania General Assembly recognized the benefits of renewable energy by passing Act 213, the Alternative Energy Portfolio Standard (AEPS) law, which mandates a schedule of advanced energy purchases by electric distribution companies (EDCs) over its 15-year horizon, including an 8% requirement for Tier I categories of renewable energy and a 10% requirement for Tier II advanced energy resources including energy efficiency and demand side management.

For wind and solar power, there is no fuel cost to be incorporated into the price of electricity, which provides price stability over the life of the project. At a time when the Commission has just opened hearings on rate cap relief, when First Energy has petitioned to break its generation rate cap, and when the recent annual PJM "Markets Report" indicated the LMP prices increased over 40% in 2005 due to fuel cost increases, especially natural gas, the ability to diversify a portfolio with zero-cost fuel provides obvious and substantial benefits to ratepayers.

Q: Can you describe in more detail the societal benefits of renewable energy?

A: When compared to conventional sources of generation in Pennsylvania, clean, renewable energy is very beneficial. It does not deplete the supply of existing fuels; it is domestic and secure supply that reduces the dependence on foreign sources; it reduces air and global warming pollution; and it reduces the health related impacts of airborne particulates and contaminants. Renewable energy is also fast growing and is creating jobs and economic development.

Pennsylvania competes with neighboring states in developing this emerging technology market. Many states have significant public incentive programs that support renewable energy and energy conservation. These states with well-funded programs supporting renewable energy also often have renewable energy portfolio standards.

Two government programs in Pennsylvania support the development of renewable energy: the Pennsylvania Energy Development Authority and the Energy Harvest Program. In 2005, annual funding for PEDA and Energy Harvest was about $10 million and $5 million respectively. In comparison, New Jersey ($140 million per year) and New York ($175 million per year) invested substantially more to develop renewable energy and conservation projects. As a result, Pennsylvania is currently at a competitive disadvantage in developing new sources of renewable energy that would be available for distribution to residential customers.

Part of any resolution to this case should be increased funding for energy conservation and renewable energy for the reasons that both renewable energy and conservation benefit consumers, the environment, public health, and create jobs.

Q: What effect does developing renewable energy have on Pennsylvania's economy?

A: It has been demonstrated that renewable energy creates new jobs and spurs economic development.

For example, a 50 megawatts wind farm located in Pennsylvania will produce 137,500,000 kilowatt-hours of clean energy annually (enough to supply some 18,975 average Pennsylvania homes); avoid 522 tons of acid rain-producing sulfur dioxide annually; avoid 75,488 tons of the global warming gas carbon dioxide annually; and provide close to 1000 job years of employment over a 20 year life. (Source: Economic Impact of Renewable Energy in Pennsylvania; available at www.cfalleghenies.org/images/EnergyStudy1.pdf)

The PJM pipeline for potential new generation projects lists 2300 megawatts of wind energy in Pennsylvania. If all of these projects are built, they would bring about $4 billion of capital investment to Pennsylvania. These are potential projects that have many hurdles before them, including competition from other states for turbines and investment. Over half may not materialize in Pennsylvania, unless Pennsylvania can offer incentives that allow these projects to compete for investment with sites in other states.

Q: Has development of renewable energy created jobs in Pennsylvania?

A: The emergence of the Pennsylvania wind energy market has already resulted in the creation of some 200 new first shift jobs at the Gamesa wind blade manufacturing plant in Ebensburg, which is located in Penelec's territory. Gamesa has also sited its North American headquarters in Philadelphia, and has broken ground on three assembly plants in Bucks County. The Ebensburg plant has been sized for additional shifts to be added as production increases. The company is forecast to provide 1000 new jobs in the Commonwealth over the next three years and is well on its way to achieving that milestone. Many more indirect jobs will be created as the multiplier effect of a new manufacturing facility works through the local supplier and service economy.

Q: How does renewable energy assist electricity customers seeking distributed generation?

A: Most renewable energy technologies can be connected to the grid or deployed as distributed generation projects that benefit customers by improving reliability and reducing stress on distribution systems. The distribution benefits of distributed generation, or DG projects, are widely recognized. For example, an A.D. Little whitepaper entitled "Reliability and Distributed Generation (available at www.encorp.com/dwnld/pdf/whitepaper/wp_ADL_4.pdf; p. 16) notes that DG can provide policymakers, regulators, wires companies, and customers with multiple options to increase reliability. DG can be installed within the distribution system or at a customer's site, as a separate solution or in combination with market-driven incentives such as interruptible programs, to improve reliability by adding generation capacity at the customer site for continuous power and backup supply; adding system generation capacity; freeing up additional system generation, transmission and distribution capacity; relieving transmission and distribution bottlenecks; and supporting power system maintenance or restoration operations with generation of temporary backup. A.D. Little, p. 16 (citation omitted). The General Assembly recognized the critical importance of renewable sources of distributed generation with a special provision in Act 213 that preferred net metering treatment of micro grids to provide electric power to critical facilities during emergencies.

Q: What forms of renewable energy do you consider to be most important now?

A: I endorse all of the renewable energy sources in Tier I of Act 213. Methane capture and wind energy are currently among the lowest cost. Pennsylvania is emerging as the leading wind power state along the east coast. We currently have more wind generation than any other Eastern state, except New York. In June, Pittsburgh hosted 5000 attendees at the American Wind Energy Association annual meeting and in October Philadelphia will host the Department of Energy annual Renewable Energy Finance Forum. Pennsylvania is becoming recognized as the East Coast leader in the emerging renewable energy market. Though it is just a small beachhead when compared to conventional power, it is exciting to lead in an emerging technology that has such strong potential for growth, that benefits the environmental and public health, and creates jobs and economic development at the same time.

Q: Please describe the status of the wind energy markets in Pennsylvania.

A: The potential Pennsylvania market for wind power is approximately 5,000 megawatts. This represents about $8.5 billion in new capital investment, with resultant environmental, human health, system security, and economic benefits.

We need more incentive funding to support this market development and to better compete with neighboring states for projects. The market is still in its early adoption stage and is fragile.

To illustrate, our wind market is now largely driven by the Renewable Energy Portfolio Standards (RPS) of eastern states, especially those in PJM. These markets are complex and still in formation. Renewable Energy Credits (REC), identified as Alternative Energy Credits (AEC) in Pennsylvania, are the means to monetize the portfolio standard requirements. They trade in a free market system. Although the AEPS rules have not been finalized, it is likely that Pennsylvania utilities will be free to buy RECs from anywhere in PJM, including Illinois.

On average, the Illinois wind resource is superior to that for Pennsylvania projects. There is a 5000 megawatt PJM wind pipeline in Illinois, twice that of Pennsylvania. The Illinois projects have operating efficiencies, called capacity factors, in the approximately 38% range compared to 33% in Pennsylvania. With the same cost to develop a project, this 15% wind resource advantage allows them to produce RECs that can be sold cheaper than those from Commonwealth projects. Since Illinois does not have a RPS, hence no requirement for Illinois utilities to buy these cheaper RECs, it is likely they will be sold into states like Pennsylvania that do have a renewable portfolio standard.

Such a scenario would favor Illinois wind development over Pennsylvania. Our Pennsylvania markets are very encouraging but still need assistance. They still require both financial and public policy support.

Q: Where does solar energy fit in?

A: Act 213 has a specific solar set-aside that, according to solar industry representatives, will require approximately 600 to 800 megawatts of installed capacity, the only specified technology carved out in the AEPS. This is currently one of the largest solar requirements in the country. The solar requirement steps up gradually over the life of the 15 year compliance period. This recognizes the comparatively high current cost of solar technology and its declining cost record as the technology advances.

The initial portfolio requirement is for only about 4 megawatts, one megawatt per year for four years. It is very important to provide further incentives for early stage demonstration projects so that consumers and service providers may develop. Incentives are the proven means that have worked in every solar market that has been successfully developed.

Solar energy systems at small scale cost about $8 per watt installed. New Jersey has a generous subsidy program of $5 per watt. It has given rise to a robust solar market, a key component of their renewable energy market strategy. They have almost 12 megawatts installed and have seen over 100 small companies emerge to support the market. In Pennsylvania we have had only a small $4 million subsidy program, administered by the Sustainable Development Fund, in the PECO territory, resulting from the PECO-Unicom merger. Those funds are now expended. We have less than 1 megawatt installed capacity across the state, with most in the PECO territory, resulting from that successful program.

Although the AEPS will require Electric Distribution Companies to purchase solar AECs, the rules are not yet finalized. We need to jumpstart the market with subsidy and transition to utility purchase, with cost recovery, via AEPS compliance.

There is a significant solar opportunity in Pennsylvania, but it requires careful encouragement during this early development.

Q: Can you explain biomass and methane recovery?

A: The capture of methane gas from landfills is currently an important source of renewable energy and becomes more attractive as natural gas prices increase. These facilities are almost at economic parity with conventional power. As micro-turbine technology advances the use of methane gas from sewage treatment plants will become technically and economically more feasible.

Currently, it is very important to continue to provide financial incentives and remove market barriers, in the form of net metering rules, for agricultural manure bio-digestion and subsequent production of Tier I electricity. Both the Pennsylvania Department of Environmental Protection and the Department of Agriculture have provided incentive grants to a few farms, but net metering rules must support these projects. The importance of this policy adoption lies not only in the power produced but also in the additional benefits of water pollution and nuisance odor control. We do need demonstration projects to show farmers the value of this energy production.

Q: How does energy efficiency and demand side management (DSM) relate to renewable energy?

A: Energy efficiency and DSM are best considered in tandem with renewable energy. The cleanest electron is one not used. In addition to my recommendations regarding renewable energy, PennFuture also addresses energy efficiency and DSM separately in this proceeding through the respective testimony of our experts, Mr. John Plunkett and Mr. Paul Chernick.

Q: Did PennFuture participate in the rulemaking that addressed the energy efficiency provisions of Act 213?

A: Of the nineteen parties submitting recommendations, Commission staff adopted PennFuture's recommended plan as the basis for the recently promulgated rule for Tier II Energy Efficiency and Demand Side Management. Mr. Plunkett, who presents testimony in this case, worked with PennFuture on this issue.

Q: Does Act 213 provide all of the funding needed to develop renewable energy in Pennsylvania?

A: No. Many states like New York and New Jersey with which Pennsylvania is competing for renewable energy investment have both renewable energy portfolio requirements and large incentive programs. The Pennsylvania General Assembly enacted Act 213, because the utilities were not including renewable energy sources into their generation portfolios in a significant way. It was intended to be a floor to encourage renewable energy development, and not a ceiling. It is the minimum required, not the amount desired.

Act 213 allows for full recovery of costs for complying with its requirements but does not provide a separate appropriation to support projects planned by renewable energy developers. A great deal of private and public capital will be required, approximately $10 billion. The Tier I renewable technologies are often more expensive than conventional power generation. In order to achieve a diverse mix of renewable energy sources, some incentive funding will be necessary to level the playing field and allow many technologies to achieve a foothold, and for future market forces to determine the most advantageous mix.

Additionally, there are several reasons why we need more incentive for renewable energy sooner. For instance, the penalty phase for noncompliance does begin until 2011. Also, a force majeure provision allows for relief of requirements if an adequate supply of a given technology is unavailable.

Pennsylvania projects will also need to compete with those in neighboring states for the attention of project developers. Those states, with strong renewable energy incentive programs, will attempt to win projects over those in the Commonwealth.

We will need to be adept at allocating incentives over time. Some forms of clean energy will require financial and policy assistance for many years; fuel cells, the foundation of the future "hydrogen economy", are an example.

Others technologies, and wind is a good example, will become more economically competitive with conventional power as fuel and other costs continue to escalate. However, this technology is still exhibiting early adoption characteristics. While the long term, cost trend for wind turbines is declining, the past 18 months have seen significant cost escalation, sometimes as much as 5 % per month, resulting from commodity steel cost pressure from China, and the on again off again uncertainty of the federal PTC (Production Tax Credit), as well as strong demand for turbines. Incentive financing remains necessary to develop a diverse renewable energy infrastructure and establish the foundation for a new, healthier energy technology mix.

Q: What are the Metropolitan Edison, Penelec, PPL, and Exelon Sustainable Energy Funds?

A: As part of the restructuring settlement agreements, sustainable development funds were created in the Exelon, PPL, Allegheny Energy, and the MetEd and Penelec service territories. For example GPU agreed to provide funding equivalent to .01

cents per kilowatt-hour that would be administered by independent agencies with boards comprised of representatives of the Intervening Parties and the company. These funds have made supported wind power projects, methane digester projects, energy conservation projects, solar power projects, and many more clean energy initiatives. Each of these funds received total funding from initial ratepayer sources of approximately $10 million to $20 million.

Q: Is there currently any dedicated fund to support renewable energy and energy conservation projects that benefit the Duquesne Light service territory?

A: No. As a result of a quirk of the restructuring process, the Duquesne Light service territory is the only major electric service territory that does not have a sustainable development fund that supports renewable energy and conservation projects. The electric restructuring process created such a fund in the Exelon, PPL, First Energy, and Allegheny Energy service territories. It is past time to correct the disparate and unfair treatment of the Duquesne Light service territory by creating a fund to support renewable energy and energy conservation projects that would benefit the Duquesne Light service territory.

Q: Have other clean energy programs been developed in Pennsylvania since restructuring created the sustainable energy funds?

A: There are two: the Department of Environmental Protection Energy Harvest Grant program and the Pennsylvania Energy Development Authority (PEDA), both of which are specifically focused on clean energy areas.

Q: Please describe the Energy Harvest and PEDA in more detail.

A: Energy Harvest is an annual grant program administered by DEP. It is focused on developing clean energy projects versus studies. It has to date completed three funding rounds, granting close to $16 million to over 100 projects, in the process leveraging another $43.7 million. The last round of EH funding went to 34 projects that are projected to conserve 37,800 megawatt hours per year of electricity.

PEDA has recently been reactivated by Executive Order. It has made its first year funding with a total of 41 awards of $15 million in grants and loans, leveraging an additional $228,695,765 and creating up to 1558 permanent and construction jobs, generating 3.5 million megawatt-hours of clean electricity and conserving another 526,225 megawatt-hours of electricity.

PEDA and Energy Harvest funding has been used as grants or loans to support a range of clean energy projects including: solar emergency backup systems, community scale wind, fuel cell development, waste coal to energy, utility scale wind farms, renewable energy marketing, expansion of solar manufacturing businesses, electric motor efficiency improvements, micro scale hydro-electric projects, a residential energy efficiency loan program, technology improvement for polymer solar cells, conversion of foundry waste heat to power, manure digestion to power projects, and more.

PEDA has the authority to provide some grants, but its primary mission is to develop tax-free revenue bonds for advanced energy projects. As such, energy projects that it approves must receive their primary funding from other institutions and/or retail investors buying revenue-backed bonds through brokerage houses. While authorized for up to $300 million in bonding capacity, PEDA needs seed money to jumpstart the market.

Both PEDA and Energy Harvest need additional funding. PECO, as part of its settlement agreement in the PSEG merger, has agreed to provide $20 million to PEDA.

Q: Are there programs that the company could voluntarily adopt that would support renewable energy and benefit the company?

A: PECO has partnered with Community Energy of Wayne, Pennsylvania to offer the PECO Wind product to its customers. It has signed up 25,000 customers to date, with the potential for 40,000. Though this program was part of a settlement agreement, PECO appears satisfied with the results. The product offers customers the opportunity to sign up via a bill stuffer and pay a fee of $2.54 per 100 kilowatt-hour blocks as part of the monthly bill payment for PECO Wind. The DOE has recognized this as one of the ten most effective programs of its kind in the country. Duquesne Light could begin a similar program.

Duquesne Light could commit to converting their vehicle fleet to a significant portion of hybrid vehicles. With the emergence of Pennsylvania indigenous biofuels, the company could sign long-term purchase agreements to purchase biodiesel fuel, currently at price parity with conventional diesel, for their transportation and heating fuels.

PPL built their new corporate headquarters in Allentown as a high technology energy efficient and environmentally benign exemplar, a LEED (Leadership in Environmental and Energy Design) Gold standard building. Schools, municipal buildings, bank retail outlets and many others have adopted LEED building standards. As long as the owner has more than a speculative interest, the 3-4% increase in capital costs is rapidly returned in lower operating costs.

PPL replaced all of its customer meters with advanced technology meters that are capable of producing data that documents usage at particular times of the day. Advanced meters would enable Duquesne Light to offer demand side management products.

Q: Considering your testimony, do you have recommendations that you would like the Commission to consider in this proceeding?

A: I recommend that the Commission order a total of $15 million in incentive funding for the development of renewable energy that benefits the Duquesne Light service territory for the period January 1, 2007 to December 31, 2010. This funding should be allocated as follows: $5 million for solar projects; $5 million for wind power; and $5 million for methane and other Tier 1 AEPS technologies. My preference would be to collect this revenue through rates on a per kilowatt-hour basis across all customer classes. But I would support other methodologies that raise the $15 million.

Q: Do you have a recommendation of administration of the funds?

A: It would be appropriate to have PEDA administer these funds. PEDA has been effective in a short time. It is a public fund and accountable that is administered by Governor Rendell's Administration and a board that includes legislators from both parties. The full implementation of the AEPS will require an investment of $10 billion in new capital in the Commonwealth. Many of the renewable energy technologies currently cost more than conventional power. We need to be able to compete effectively with neighboring states with continuous funding streams from system benefit charges. New York and New Jersey each have approximately $ 175 to 140 million per year respectively in clean energy funding.

The $15 million administered by PEDA will allow the Duquesne Light service territory to better compete for a full share of this emerging technology sector and for ratepayers to benefit sooner from environmental and power system improvements.

The $5 million for solar development in the Duquesne Light service territory would jumpstart the solar industry in the Pittsburgh region to the benefit of environment, ratepayers, and the local economy.

Q: In addition to the funding you have described, what policy changes do you recommend be adopted by Duquesne Light?

A: I have one recommendation and three suggestions.

I recommend that Duquesne Light partner with an organization with expertise in marketing renewable energy to consumers and offer a product similar to PECO Wind, or other renewable energy product. That product should be comprised of at least 75% AEPS Tier I qualified resource, generated in Pennsylvania. They should introduce the product no later than January 2008.

The program should be modeled upon the PECO Wind initiative. This program would be counted as the voluntary market, not that required by the AEPS. The company would make money and its would develop wind energy capacity above the minimum required by the AEPS, yet all of it demanded and paid for by customers willing to pay more, voting with their money for more clean energy. If the Company will not initiate such a program voluntarily, the PUC should order it to do so.

I have three suggestions. First, the Company should commit to having 20% of their eligible transportation vehicles be hybrid vehicles. Second, the Company should commit to purchasing Pennsylvania refined biodiesel fuel for 20% of its total transportation and other diesel fuel needs. Third, the Company should commit to a LEED Silver standard for one half of all of its new building construction or existing building rehabilitation, for which LEED standards exist.

That concludes the direct testimony of John Hanger.

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John Hanger is the president and CEO of Citizens for Pennsylvania's Future (PennFuture), a public policy research and advocacy organization devoted to improving Pennsylvania's environment and economy. Since 1998, Hanger has been building PennFuture and its membership and advancing its mission to create a just future where nature, communities and the economy thrive. As president of PennFuture, Hanger supervises a staff of 16 in offices in Philadelphia, Harrisburg, West Chester and Pittsburgh. PennFuture serves as a watchdog of state government to enforce existing environmental laws and to transform markets in order to conserve Pennsylvania's natural resources. PennFuture focuses on issues in four areas: energy and the environment, mining, watershed protection and air quality.

Hanger is particularly involved with PennFuture's work to promote clean energy technologies and to increase the supply and demand for clean electricity products. PennFuture and Hanger played a major role in drafting and enacting in November 2004 Pennsylvania's Alternative Energy Portfolio Standards Act. PennFuture also co-chaired the campaign that passed the $625 million Growing Greener bond question on the ballot in May 2005.

In January 2003, Hanger was appointed co-chair of Governor Rendell's Energy and Telecommunications Transition Team.

From April 1993 to June 1998, Hanger was a commissioner with the Pennsylvania Public Utility Commission (PUC). Hanger served on the Electricity Committee, the Consumer Affairs Committee, and the Committee on Energy Resources and the Environment of the National Association of Regulatory Utility Commissioners (NARUC). He advocated for policies that allow consumers to choose their electric, gas, and telephone companies, for policies that assist low-income families and those that benefit the environment, such as net metering, energy conservation and renewable energy.

As an expert on energy and environment issues, public utility regulation, and competition in the electricity, gas and telephone industries, Hanger has testified before the U.S. Congress and many state legislatures. He has authored numerous articles, written leading regulatory decisions and lectured widely to diverse audiences.

Prior to becoming commissioner, Hanger served as legal counsel to Pennsylvania Public Utility Commissioner Joseph Rhodes from 1988 to 1993. From 1984 to 1988, he worked at Community Legal Services, Inc. of Philadelphia, serving as public advocate representing 500,000 municipal customers of the City of Philadelphia's municipal gas, water, and sewer utilities.

Hanger is a 1979 graduate of Duke University and a 1984 graduate of the University of Pennsylvania School of Law.

State of Pennsylvania

Before the Public Utility Commission

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. 00061346**
Duquesne Light Company	)	

Citizens for Pennsylvania's Future

Sur-Rebuttal Testimony of John Hanger

August 15, 2006

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is John Hanger. My business address is 610 North Third Street, Harrisburg, PA 17101.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I have been President and Chief Executive Officer of Citizens for Pennsylvania's Future ("PennFuture") since it was founded in 1998.

Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A: Yes, I have.

Q. WHAT IS THE SUBJECT OF YOUR SUR REBUTTAL TESTIMONY?

A: My sur rebuttal testimony responds to points raised in the rebuttal testimony of the following witnesses: 1) Mr. Stephen J. Baron on behalf of Duquesne Industrial Intervenors and the Industrial Energy Consumers of Pennsylvania; and 2) Mr. Brian Kalcic on behalf of the Office of Small Business Advocate.

Q. DO YOU AGREE WITH MR. BARON'S ARGUMENT THAT INCREASING RATES FOR A CLEAN ENERGY FUND SHOULD BE

REJECTED ON THE GROUNDS IT DOES NOT RELATE TO TRANSMISSION AND DISTRIBUTION?

A: No. This argument was recently dismissed in an August 4, 2006 decision by the Commonwealth Court of Pennsylvania regarding the proposed increase in PPL Electric Utilities Corporation's (PPL) retail distribution and transmission rates.

In that case, PP&L Industrial Customer Alliance (PPLICA) opposed the continued funding of the Sustainable Energy Fund (SEF) in PPL's service territory, contending that the cost was unrelated to distribution service and should therefore not be funded by distribution ratepayers. PPLICA also argued that any benefits from the SEF program related to generation service and not to distribution service.

The Court, however, upheld SEF's argument that their programs did directly relate to the distribution system. SEF explained in its testimony that:

"First, energy conservation and demand management projects funded by SEF benefit the distribution system by reducing customer load or shifting that load to lower-peak periods, thus, reducing the loading and stress on the distribution system extending its life and ending or delaying the need for expensive distribution system upgrades. SEF ST. No.1 at 13; R. 259a. The *distribution* benefits of energy conservation and demand management are widely recognized. A summary of these benefits is presented in a report entitled *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-*

Cost, and Efficient Electricity Services To All Retail Customers, portions of which appear in the evidentiary record at pages 13 through 15 of SEF Statement No. 1. R. 259a-R.261a."

I provided similar testimony in this case and explained the distribution benefits of funding alternative energy and conservation programs. The recent Commonwealth Court decision establishes that our proposal for increased funding to create a sustainable energy fund in the Duquesne Light territory does directly relate to transmission and distribution rates.

Q. MR. BARON STATES A UNIFORM KWH CHARGE TO FUND CLEAN ENERGY WILL CREATE AN UNREASONABLE BURDEN FOR LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS. DO YOU AGREE WITH THIS STATEMENT? WILL THIS AFFECT THEIR COMPETITIVENESS IN THE MARKETPLACE?

A: No. Commercial and industrial customers in the other electric service territories in Pennsylvania already incur a .01 cent per kWh charge to fund clean energy and conservation projects, and there is no evidence that the charge adversely impacts the economic viability of those customers. In addition, other commercial and industrial customers in the region face even higher surcharges. All six New England States plus New York and New Jersey have a system benefits charge on electric utility distribution services ranging from .014 to .030 cents per kWh.

Q. HAVE YOU REVIEWED MR. KALCIC'S REBUTTAL TESTIMONY ON BEHALF OF THE OFFICE OF SMALL BUSINESS ADVOCATE?

A: Yes I have.

Q. DO YOU HAVE ANY COMMENTS ON MR. KALCIC'S TESTIMONY?

A: Yes. I disagree with the statements Mr. Kalcic makes on page 8, lines 17 through 35 where he contends PennFuture wants to hold the company to a separate and distinct standard when the AEPS already requires Duquesne Light to acquire renewable energy.

The AEPS was created to boost jobs and economic development in Pennsylvania, increase investment for alternative energy technologies in Pennsylvania, improve the environment of Pennsylvania, reduce pollution, diversify the fuels used to make electricity in Pennsylvania, and build more generation that will increase reliability of the electric system in Pennsylvania. The AEPS creates a minimum requirement for clean energy generation. It does not preclude the establishment of other incentives that promote the development of alternative energy in Pennsylvania.

Q. DO YOU AGREE WITH MR. KALCIC'S STATEMENT THAT REQUIRING DUQUESNE TO INVEST IN CERTAIN TIER I AND TIER II RESOURCES IS INCONSISTENT WITH THE AEPS?

A. No. Mr. Kalcic states that PennFuture would like Duquesne to invest in certain technologies like wind, solar, and energy efficiency. He argues that providing incentives for some resources and not others will create a non-level playing field amongst Tier I and Tier II resources.

The AEPS is not premised on some mythic level playing field amongst Tier I and Tier II resources, as presumed by Mr. Kalcic. For example, the AEPS has a separate solar requirement in order to promote development of that particular technology and ensure that solar does not compete against other technologies. Similarly, the AEPS divides alternative energy technologies into two tiers to ensure that Tier 1 technologies do not compete with Tier 2 technologies.

In addition, Mr. Kalcic misinterprets PennFuture's position. PennFuture favors funding that broadly targets all Tier 1 technologies and energy conservation.

Q. DO YOU AGREE WITH MR. KALCIC'S ARGUMENT THAT ALTERNATIVE ENERGY CREDIT BANKING AND OTHER RENEWABLE PORTFOLIO STANDARDS ARE ENOUGH TO ASSURE ALTERNATIVE ENERGY RESOURCES ARE AVAILABLE TO UTILITIES BEFORE THEIR COMPLIANCE WITH THE AEPS BEGINS?

A. No. While Mr. Kalcic is correct that other states' renewable portfolio standards are beginning to drive the market for renewable energy, there is no direct incentive for this growth to occur in Pennsylvania. The Commonwealth needs to develop its own market to compete with those in neighboring states for the attention of project developers. States with strong renewable energy incentive programs will have an advantage at attracting clean energy projects and the economic benefits that those projects bring with them.

That concludes Mr. Hanger's Sur-Rebuttal testimony.

State of Pennsylvania

Before the Public Utility Commission

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. 00061346**
Duquesne Light Company	)	

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Citizens for Pennsylvania's Future
Statement 2

Direct Testimony of John J. Plunkett

July 7, 2006

Q: Please State your name and business address.

A: I am John Plunkett. I am a partner in the Green Energy Economics Group, 1002 Jerusalem Road, Bristol, Vermont 05443.

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

A: Citizens for Pennsylvania's Future ("PennFuture") is sponsoring my testimony.

Q: What is the purpose of your testimony?

A: My purpose is twofold. First, I estimate the range of economic and electricity savings the Pennsylvania Public Utility Commission ("the Commission") can expect if Duquesne Light ("the Company") invests in energy efficiency in its territory on a scale and at performance commensurate with ratepayer-funded energy-efficiency portfolios administered in other jurisdictions. Second, I recommend that the Commission direct Duquesne Light to invest $44 million over the next three years on a comprehensive portfolio of programs designed and implemented to achieve 35 MW and 176 GWh in summer peak demand and annual energy savings, respectively from energy-efficiency improvements in the homes and businesses of its customers.

Q: Summarize your qualifications.

A: I graduated Phi Beta Kappa with a B.A. in Economics, with Distinction, from Swarthmore College. I have twenty-eight years of experience in energy utility planning, concentrating on demand-side management as a resource and business strategy for electric and gas service providers. I recently co-founded Green

Energy Economics Group, a consultancy specializing in energy efficiency and renewable resource economics, with Francis Wyatt, my colleague since 1992. We provide technical and strategic assistance with energy-efficiency and distributed generation portfolio development, design, analysis, planning, administration, implementation management support, oversight, performance verification and evaluation, performance incentive mechanisms, and regulatory and ratemaking treatment. I have testified as an expert witness on energy efficiency as an electricity and gas supply alternative in regulatory proceedings in the U.S. and Canada, including New York, New Jersey, Connecticut, Indiana, Florida, Ontario and Quebec. I have led several major studies of economically achievable efficiency potential, including New York, Vermont, and Maine. I have also led collaborative teams in the estimation of electric, economic, and environmental impacts of energy-efficiency portfolios, including New Jersey, Maryland, and two Chinese provinces.

For the past six years I have served on the senior management team of Efficiency Vermont, the nation's first statewide electric efficiency utility, which has been responsible for managing Vermont's $70 million efficiency portfolio through 2005 since its inception in 2000. Efficiency Vermont has exceeded its energy and economic performance goals on or under budget during both its three-year contracts, and has just entered a third contract through 2008.

Since July 2003 I have led the Natural Resources Defense Council consulting team working with China's Jiangsu province to develop and implement Energy-Efficiency programs as "energy-efficiency power plants ("EPP"). I am leading an

Asian Development Bank consulting team to analyze the energy, economic, financial, and environmental prospects of launching an EPP in Guongdong province in 2007.

I have been leading the assessment and development of demand-side alternatives to transmission and distribution investments in Vermont's "southern loop" on behalf of Vermont Electric Power Company and Central Vermont Public Service (April 2005 – present). In parallel, I am leading development of first-stage implementation plans for possible deployment of targeted demand-side management programs on behalf of CVPS.

I led the economic analysis of the $150 million, five-year Clean Energy Initiative on behalf of the Long Island Power Authority in 1999; since 2002 I have advised LIPA on future energy-efficiency spending and performance goals, most recently involving long-term spending and savings goals for the next ten years. I have served as an economic advisor to Northeast Energy Efficiency Partnerships since 1998, for which I have led several analyses of a variety of regional utility energy-efficiency initiatives. In 2005 I served as NEEP's technical advisor on regional protocols for interstate Energy-Efficiency portfolio comparison. I have also been an economic advisor to the non-utility parties engaged in energy-efficiency collaboratives with Massachusetts electric and gas utilities since 1999. (Exhibit PF-JP_1 provides Mr. Plunkett's full resume).

Q: Have you testified previously before this Commission?

A: Last year I submitted testimony on behalf of PennFuture regarding Energy-Efficiency portfolio investment in the Exelon merger proceeding in Docket No. A-110550F0160. On behalf of the Office of Consumer Advocate ("OCA"), I testified in 1985 on the potential for energy efficiency to provide an economical alternative to completing and operating the second unit of Limerick nuclear power station. I again testified for OCA on prudence cost adjustments proposed concerning Limerick 1 in 1986.

Q: Have you done other work related to energy efficiency in Pennsylvania?

A: In 1990, I co-authored three volumes of the five-volume report on demand management planning commissioned by the Pennsylvania Energy Office. Most recently, I led the consulting team working on behalf of PennFuture that developed proposed methodology for counting efficiency credits in the Commission's rulemaking concerning the Alternative Energy Performance Standard ("AEPS").

Q: Please summarize your findings and conclusions in this matter.

A: Regulators in other states have directed utilities to fund, and in most cases, administer, comprehensive ratepayer-funded portfolios of programs designed and implemented to save electricity by improving the energy-efficiency of buildings, products and equipment used by their customers. Most of these portfolios have been operating for more than three years and are expected to continue under current and in some cases increased funding levels. Duquesne Light currently administers energy-efficiency programs limited to low-income customers. It is reasonable for the Commission to expect Duquesne Light to expand and intensify these limited efforts to procure electricity savings from efficiency programs at costs well below the value of avoided electricity supply.

I draw on a range of recent experience by demand-side management portfolio administrators in the northeastern United States since 2002 to estimate a range of spending and savings within which Duquesne Light can reasonably be expected to perform. I estimate that the Company should be capable of administering a portfolio at least on the relative scale of Maine, which has the most limited funding of the jurisdictions examined. At the upper end of a reasonable investment range for Duquesne Light would be a portfolio sized and performing comparably to that of Massachusetts utilities. Well within this range would be spending and savings commensurate with what New Jersey has accomplished from 2002 to 2004.

I apply the sector-level spending and savings of energy-efficiency portfolios observed in these states over the past few years to projected sales by the Company to estimate the range of energy-efficiency portfolio funding and associated savings that Duquesne Light should be able to manage over the next three years. New Jersey spent $204 million (2005 dollars) from 2002 to 2004 on electricity demand-side management statewide through the NJ Clean Energy Programs. This is part of the billion-dollar, eight-year portfolio investing in comprehensive energy efficiency (and solar) programs serving all New Jersey electricity and gas customers since 2001. Were Duquesne Light to spend an amount proportional to its electricity sales in its Pennsylvania territory, it could reasonably expect to reduce peak generating capacity requirements by 35 megawatts (MW) and 176 gigawatt-hours (GWh) in electricity generation.

It is reasonable for the Commission to expect energy-efficiency investment to cost more or less the same to Pennsylvania customers as it was found to be in New Jersey. Consequently, offering similar energy-efficiency to households and businesses in the Company's territory over the next 3 years (2007-2009) would reduce their electricity bills by a net $104 million in present value, i.e., the difference between the value of the savings ($144 million) and the costs recovered through rates to achieve them ($40 million).

I recommend that the Commission direct Duquesne Light to spend $14.8 million annually between 2007 and 2009, and to achieve savings over the three-year period of 35 MW and 176 GWh of summer peak demand and annual energy savings, respectively. Such cost-effective portfolio expenditures and performance can be expected to reduce total costs of electric service to the Company's customers. Accordingly, I recommend that the Commission include them in the Company's cost of service and to allow it to recover them through rates.

Q: Why do you recommend that the Commission require the Company to spend an amount comparable to that of New Jersey on an energy-efficiency investment portfolio as a condition of approval for the requested rate increase?

A: Acting in the best interests of its shareholders, the Company seeks permission to raise rates charged for electric service to recover increases in costs experienced since the time the rate caps took effect. It is fair and reasonable for the Commission to expect and direct the Company to take actions that will reduce the economic harm to customers caused by the rate increases it seeks. A sustained, well-managed energy efficiency portfolio producing cost-effective electricity savings will provide net economic benefits that partially offset the burden of higher rates that may be granted in this proceeding.

Q: Did you assess the range of spending and savings that Duquesne Light could expect in implementing energy-efficiency portfolios?

A: Yes. We began by comparing energy-efficiency portfolio depth and yield for various jurisdictions in the Northeastern US.

Q: What states did you include in your comparison of energy-efficiency portfolios?

A: I chose states with jurisdictions implementing energy-efficiency programs in the Northeast United States, including: Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, and Vermont.

Q: For which years were you able to obtain spending and savings data, and for which jurisdictions?

A: For most jurisdictions I found spending and savings data from 2001 to 2004. Data was not available in the early years for three of the jurisdictions. Data was missing for 2001 and 2002 for Efficiency Maine and New Hampshire and for 2001 for New York State Energy Research and Development Authority (NYSERDA).

Q: What did your comparison reveal?

A: First, the energy-efficiency spending and savings levels vary widely across the Northeast states. Second, savings depth (MWh savings per MWh sales) generally increased as spending depth (energy-efficiency spending per MWh sales) increased. Third, savings yield (kWh savings per energy-efficiency spending) tended to decrease as savings depth increased.

The tables in Exhibit PF-JP_2 provide the residential and non-residential spending depth, savings depth and savings yield for eight Northeast jurisdictions. These same tables will be part of the forthcoming ACEEE 2006 Summer Study.

Q: Explain the relationship between spending/savings depth on the one hand and savings yield on the other.

A: The laws of diminishing marginal returns apply to energy efficiency investment as it does in the rest of the marketplace. Every customer can be thought of as having a supply curve for efficiency savings with each increment of efficiency costing more than the last. All potential savings achievable for less than the cost of avoided supply are cost-effective. Portfolios concentrating on the easier and cheaper efficiency opportunities will yield high savings per dollar invested; deeper investments reach farther up the supply curve among technologies and customers and therefore will produce lower aggregate yields. For example, residential efficiency programs that focus on lighting tend to provide high savings yield because the compact fluorescent technology is relatively inexpensive for the high energy savings it provides.

Q: Did you use this information to project a range of Duquesne Light energy-efficiency portfolio spending and savings.

A: Yes.

Q: How do you define your range of reasonable performance expectations for Duquesne Light?

A: I looked at the range of energy-efficiency spending and savings bracketed by the comparison of energy-efficiency portfolios in the Northeast. From that range I chose representative jurisdictions for low, medium and high energy-efficiency scenarios. I chose Efficiency Maine for the low end of the range with its low spending and savings, but high yields due to cream skimming. I selected Massachusetts for the high end of the range, since it was among the highest in spending and savings. For medium energy-efficiency performance I chose New Jersey, because its spending and savings fell in the middle of the range and also because it is a neighboring state to Pennsylvania.

Q: How much should the commission expect Duquesne Light to spend and save over the entire range of performance you have established from these three other states?

A: If Duquesne Light were to implement efficiency programs in its territory, it could expect to spend between $9 and $141 million with savings between 44 to 424 annual GWh over three years. Exhibit PF-JP_3 shows the spending and savings for Duquesne Light under low, medium and high performance scenarios.

Q: Of the states reviewed, which did you use as a primary projection for the Duquesne Light service territory?

A: We used the New Jersey Clean Energy Portfolio.

Q: What is the New Jersey Clean Energy Portfolio?

A: The New Jersey Clean Energy Portfolio includes electric and natural gas energy-efficiency programs that are managed by New Jersey's seven investor-owned electric and natural gas utilities since 2001. The Portfolio also encompasses renewable energy programs initially managed by the utilities now run by the New Jersey Office of Clean Energy. Exhibit PF-JP_4 lists the 2004 statewide program spending and savings results by sector for the programs managed by the utilities.

Q: On what economic basis does New Jersey justify investing in this portfolio?

A: New Jersey's support for energy-efficiency investments is based on an understanding of the market barriers facing their customers preventing them from investing in cost-effective efficiency. New Jersey's efficiency portfolio creates economically achievable efficiency potential that can be procured with strategies targeted to overcome these market barriers.

Q: Would the same economic rationale apply in Pennsylvania?

A: *Yes. The same market barriers stand in the way of lowering the Commonwealth's* total electricity costs. Overcoming these barriers with successful market strategies produces major electric savings to and economic benefits to consumers in the form of lower electricity bills. Helping Pennsylvania households and businesses save money by saving energy helps the Commonwealth's economy.

Q: Do you believe that these programs would be effective in Duquesne Light *territory?*

A: Yes. Everywhere else that efficiency portfolio administrators have deployed best practices in market strategies, they have succeeded and produced large and highly cost-effective electricity savings. This is true elsewhere in North America where comprehensive efficiency portfolios have been deployed, particularly in the neighboring states of New Jersey, New York, and Maryland. Ample evidence from New England, Wisconsin, California, and the Pacific Northwest demonstrates that best practices in demand-side management program design and implementation can produce large and cost-effective electricity savings.

Q: How much money would it take to fund a portfolio of electric efficiency programs of comparable scale in Duquesne Light's territory?

A: It would require a total of $44 million over the next three years, or an average per year of $14.8 million.

Q: How did you arrive at this estimate?

A: The Duquesne Light spending is proportional to the projected spending on electric energy efficiency through the New Jersey Clean Energy Program, based on MWh sales. The residential and non-residential portions of spending were separately scaled using the sales from each respective sector. For example, since the Duquesne Light residential sales were 5% of 3 years of New Jersey's residential sales, Duquesne Light's estimated residential energy-efficiency spending is also 5% of New Jersey's three-year residential spending (adjusted for inflation).

Q: Is this reasonable?

A: Yes, this is a reasonable and an unbiased method for establishing efficiency portfolio funding requirements for Duquesne Light given New Jersey's clean energy spending. It accurately reflects the different split between Duquesne Light's and New Jersey's residential and nonresidential customers by extrapolating the New Jersey spending per kWh sold between residential and nonresidential customers.

Q: How much electricity would Duquesne Light customers save if Duquesne Light invested the same amount relative to its electricity sales on energy efficiency as does New Jersey?

A: Duquesne Light could expect to acquire 35 Summer Peak MW and 176 GWh cumulative annual savings in three years.

Q: Explain the basis for your estimate of electricity savings in Duquesne Light's territory from comprehensive efficiency investment.

A: The Duquesne Light savings were estimated by multiplying the estimated Duquesne Light spending times the New Jersey MWh savings per dollar spent. I assumed the average incremental MWh savings per dollar spent from the New Jersey Clean Energy actual results for the years 2002, 2003 and 2004. The residential and non-residential savings per dollar figures were calculated separately and multiplied times the respective residential and non-residential energy-efficiency budget estimates for Duquesne Light.

Q: Why is it reasonable to assume that Duquesne Light customers would realize the same electricity savings yield from efficiency programs that New Jersey achieved from its investment?

A: I cannot think of a valid reason to expect that program delivery or efficiency technology costs would necessarily vary decisively between adjoining states and interconnected markets. Experience strongly suggests otherwise. For example, electricity yields per dollar between Massachusetts utilities vary widely, but not enough to influence decision-making.

Q: How much would these electricity savings be worth to Duquesne Light's customers?

A: These programs could provide a net present value of $104 million in electric system net benefits – $144 million in electric benefits and $40 million in electric utility costs – with an overall electric system benefit/cost ratio of 3.58.

Q: On what do you base your estimate of economic net benefits?

A: I first estimated the Duquesne Light territory utility costs as described above – applying New Jersey energy-efficiency spending depth to Duquesne Light sales. I then calculated the electric benefits from the net present value of electricity savings based on avoided costs from Duquesne Light Rider No. 8 – Fixed Price Service, using GL rates for the estimate of avoided costs.

Q: Why did you choose to use these rates for your estimate of avoided costs?

A: I believed that these reasonably represented current market prices, because they were recently issued in May 2006 and are based on generation charges from a competitive request for proposal. These rates will understate the avoided costs, because avoided transmission and distribution capacity costs are not included.

Q: Based on your findings from your analysis, what do you recommend to the Commission?

A: As a condition of its approval of any rate increase in this proceeding, I recommend that the Commission require the Company to commit to $14.8 million in annual funding for a comprehensive efficiency portfolio serving Duquesne Light's customers over the next three years. The Commission should order Duquesne Light to enter a collaborative settlement process whereby it and other interested parties would develop an action plan for design, planning and administering, and overseeing the efficiency investment portfolio. The Commission should direct the parties to submit a joint proposal for settlement of these issues within six months of the date of its order in this rate case. The Commission should then approve, reject, or modify the proposed settlement as it sees fit. Within three months of the Commission's order approving or modifying the joint settlement proposal, I recommend that the Commission order the signatories to make a compliance filing establishing the contents of the portfolio, electricity and economic savings goals, a funding mechanism, and an administrative and oversight structure.

Q: Why should the Commission adopt these recommendations in this proceeding?

A: These recommendations will ensure that Duquesne Light ratepayers pay for and receive just and reasonable service after the rate case is concluded. The process I recommend for achieving this objective is similar to that leading up to and resulting from the recent decision by the NY PSC approving a settlement between Con Ed, PSC Staff, NRDC and others. That decision calls for Con Edison to spend $250 million over the next three years on demand-side management beyond the statewide efforts administered in its service territory by NYSERDA.

Q: In your opinion should the Commission adopt New Jersey's current programs "as is"?

A: No, not necessarily. It may be appropriate to modify these programs or target different markets. The crucial point is that the efficiency portfolio serving Duquesne Light's customers should be designed and implemented to yield maximum electric and economic savings in the long run. The Commission ultimately must decide how the portfolio will be administered. Responsibility for administration of New Jersey's clean energy portfolio is transferring to independent contractors, selected through a competitive bidding process.

Q: In you opinion should the Commission direct Duquesne Light to adopt your estimated savings for resource planning purposes?

A: No. The goals established pursuant to the action plan I recommend should be integrated into Duquesne Light's planning for generation, transmission and distribution.

Q: Wouldn't the budgets necessary to support efficiency investment in Duquesne Light's territory raise rates?

A: Not when considered over the lifetime of the portfolio's investments. This is because the portfolio can be expected to yield 3.6 times more benefits in terms of electricity supply cost savings than the present worth of program spending funded through rates. How much rates rise or fall due to the portfolio in any one year depends on the cost recovery period for the efficiency portfolio expenditures relative to the lifetime of the efficiency portfolio yield. Program costs may raise rates during the three years of program implementation if they are fully recovered in the years they are incurred. Extended recovery to more closely reflect the life of the portfolio's savings could lower rates over the entire period.

That completes the direct testimony of Mr. John J. Plunkett.

RESUME

John J. Plunkett
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Trained as an economist, I have 27 years of experience in energy utility planning, concentrating on energy-efficiency as a resource and business strategy by energy service providers. I have played key advisory and negotiating roles for clients on virtually all aspects of electric and gas utility demand-side management, including residential, industrial and commercial program design, implementation, oversight, performance incentives, and monitoring and evaluation planning, and their respective roles in business, regulatory, ratemaking, resource planning and policy decisions. I have also led and/or prepared numerous analyses and reports on the achievable potential for cost-effective efficiency and renewable resources. I have testified as an expert witness in regulatory proceedings throughout North America.

PROFESSIONAL EXPERIENCE

November 2005-present
Partner, **Green Energy Economics Group, Inc.**, Bristol, VT
Consultancy specializing in energy-efficiency and renewable resource portfolios investing in electricity and gas savings, co-founded with Francis Wyatt, PE, a co-worker since 1992. Technical and strategic assistance with portfolio development, design, analysis, planning, administration, implementation management support, oversight, performance verification and evaluation, performance incentive mechanisms, and regulatory and ratemaking treatment. Current assignments include:

- Leading Natural Resources Defense Council consulting team working with China's Jiangsu province to develop and implement "energy-efficiency power plants." (July 2003 – present)
- Senior policy advisor to and senior management team member of Efficiency Vermont, the nation's first statewide energy-efficiency utility. (2000-present)
- Economic advisor under subcontract with Optimal Energy, Inc. to develop a business plan for Long Island Power Authority to invest in 500 megawatts of energy efficiency resources over ten years. In progress.
- Leading assessment and development of demand-side alternatives to transmission and distribution investments in Vermont's "southern loop" on behalf of Vermont Electric Power Company and Central Vermont Public Service, including implementation planning. (April 2005 – present)

On these and other assignments I work closely on design, planning, and implementation support.with Optimal Energy on commercial/industrial efficiency investments and with Vermont Energy Investment Corporation on residential and renewable investments.

1996 – 2005

Partner, **Optimal Energy, Inc.**, Bristol, VT.

Strategic planning, implementation management and regulatory support on energy-efficiency investment by regulated and unregulated businesses. Lead technical consultant for Natural Resources Defense Council (NRDC) on demand-side management portfolio design and economic analysis in Shanghai and Jiangsu province. Part of Efficiency Vermont senior management team responsible for administering statewide energy efficiency portfolio from inception through third three-year contract. Lead author and expert witness on report recommending revamped performance incentive for Connecticut efficiency program administrators, on behalf of Office of Consumer Counsel. Led statewide efficiency and renewable potential study for New York and efficiency potential study for Vermont. Lead author and expert witness on assessment of economically achievable transmission capacity from efficiency resources, on behalf of Vermont transmission utility. Advisor on economic analysis of clean energy initiative for the Long Island Power Authority, and on program cost-effectiveness in Massachusetts and New Jersey collaboratives, and regional market transformation initiatives on behalf of Northeast Energy Efficiency Partnerships.

1990 – 1996

Senior Vice President, **Resource Insight, Inc.**, Middlebury, VT.

Provided analysis of DSM resource planning/acquisition and integrated resource planning in numerous states. Investigated regulatory and planning reforms needed to integrate demand-side resources with least-cost planning requirements by public utility commissions. Prepared, delivered and/or supported testimony on wide variety of IRP, DSM, economic, cost recovery and other issues before regulatory agencies throughout North America. Consulted and provided technical assistance regarding utility filings. Responsible for presentations and seminars on DSM planning and evaluation.

1984 – 1990

Senior Economist, **Komanoff Energy Associates**, New York, NY.

Directed consulting services on integrated utility resource planning. Testified on utility resource alternatives, including energy-efficiency investments and independent power. Examined costs and benefits of resource options in over twenty-five proceedings. Supported major investigation into utility DSM investment and integrated resource planning. Designed and co-wrote microcomputer software for evaluating the financial prospects of customer-owned power generation. Wrote and spoke widely on integrated planning issues. Contributed to least-cost planning handbooks prepared by the National Association of Regulatory Utility Commissioners and by the National Association of State Utility Consumer Advocates.

1978 – 1984

Staff Economist, **Institute for Local Self-Reliance**, Washington, D.C.

Project development and management for a non-profit consulting firm specializing in energy and urban economic development. Project manager and economist for an investigation into the economic impact on small generators from electric utilities' grid-interconnection requirements. Coordinated research by three electrical engineers, and analyzed the impact of interconnection costs on wind, hydroelectric and cogeneration projects in seven utility service areas in New York. Provided technical coordination in cases before the District of Columbia Public Service Commission involving gas and electric utility demand management investment, non-utility generation pricing, both for the D.C. Office of People's Counsel.

EDUCATION

B.A., Economics *with Distinction, Phi Beta Kappa*, Swarthmore College, Swarthmore, PA, 1983. Adams Prize in Quantitative Economics.

HIGHLIGHTS OF PROJECT EXPERIENCE

EFFICIENCY PORTFOLIO DESIGN AND PLANNING

- Consulting team leader on development, assessment, and implementation of demand-side management investment portfolios for China, for the Natural Resources Defense Council. (July 2003 – present) Responsible for framing and conducting benefit/cost analysis of efficiency program portfolios for Jiangsu province and Shanghai municipality, including assessment of 300-MW Efficiency Power Plants for prospectus by Asian Development Bank; co-authoring portfolio analysis report; and program implementation planning and support. Led development and application of program and portfolio economic analysis tool based on model developed with Optimal Energy for U.S. DSM planning. Assisting Jiangsu Province with design and planning for first-stage implementation of two Efficiency Power Plant (EPP) programs investing 100 million RMB in 2006 on high-efficiency retrofits to industrial motors and drives and commercial lighting and cooling.

- Senior Policy Advisor and member of senior management team, Efficiency Vermont, the world's first Energy Efficiency Utility, currently operating under a US$52 million three-year contract with the Vermont Public Service Board to deliver statewide energy-efficiency programs for the customers of Vermont's twenty-one electric utilities. Senior management team member from inception in 2000 to present; policy advisor, 2002-present; led program development and planning, 2000-2002. Responsibilities included leading development and negotiation of energy-efficiency portfolio performance goals and performance incentive mechanism for three successive contracts totaling US$127 million over nine years.

- Advisor to consulting team leader on planning and management support for Long Island Power Authority's Clean Energy Initiative, which is currently investing US$40 million annually (January 2003 – present). Assisting with development and economic analysis of ten-year US$700 million efficiency power plant portfolio. Previously, consulting team leader on energy-efficiency program planning and implementation management support. (July 1998 – January 2001). Coordinated development of core energy-efficiency and renewable programs in LIPA's first five-year clean energy portfolio, investing US$160 million in efficiency, load-management, and solar power programs.

- Consulting team leader for assessment of economically achievable potential for distributed resources to solve a variety of transmission and distribution contingencies in the "southern loop" of Vermont, on behalf of the Vermont Electric Power Company and Central Vermont Public Service. 2005-present.

- Leading program planning for local, accelerated targeted efficiency investment demonstration in Vermont's southern loop, on behalf of Central Vermont Public Service (in progress)

- Economic advisor to Northeast Energy Efficiency Partnerships (NEEP) on cost-effectiveness of regional market-transformation initiatives. Most recently served as technical advisor on a report assessing need for and approaches to standardizing protocols for estimating DSM savings throughout the northeastern US. (1998-present)

- Co-author (with Optimal Energy and Vermont Energy Investment Corporation), Comments on Efficiency Maine's 2006-2008 Program Plan, on behalf of Maine's Office of Public Advocate, September 2005.

- Leader of analysis of economically achievable potential for energy-efficiency resources to offset loss of output in the event of early retirement of the Indian Point nuclear generation station, on behalf of the National Academy of Sciences. May-October 2005.

- Co-author (with Paul Chernick) of testimony assessing planned energy-efficiency investments by British Columbia Hydro, on behalf of the British Columbia Sustainable Energy Association and British Columbia Sierra Club, August 2005.

- Written testimony recommending energy-efficiency portfolio investment levels and savings goals in utility merger application before the Pennsylvania Public Utility Commission, Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group with and into Exelon Corporation, on behalf of the Pennfuture Parties, June 28, 2005.

- Co-author of and expert witness supporting "Getting Results: Review of Hydro Quebec's Proposed 2005-2010 Energy Efficiency Plan," before the Quebec Energy Board, on behalf of a coalition of business, municipal, and environmental groups (January-March 2005)

- Testimony (with Ashok Gupta) before the New York Public Service Commission supporting joint settlement proposal for 300 MW of additional efficiency investment in Con Edison territory, on behalf of the Natural Resources Defense Council, Pace Energy Project, and the Association for Energy Affordability (December 2004 – January 2005).

- Report and testimony on performance incentives for administrators of conservation and load management programs in Connecticut, on behalf of Connecticut Office of Consumer Counsel. (February 2003 – August 2004). DPUC adopted recommended performance incentive mechanism for 2006 program year.

- Project leader, including report and testimony, for consulting team projecting potential for demand-side resources to defer the need for major transmission upgrades, on behalf of Vermont Electric Power Company. (November 2001 – December 2004)

- Report and testimony on Opportunities for Accelerated Electrical Energy Efficiency in Quebec 2005 – 2012, on behalf of Regroupment National des Conseils Regionaux de L'environnement du Quebec, Regroupment des Organisms Environnementaux en Energie and Regroupment pour la Responsabilite Sociale des Entrepreses. (March – June 2004)

- Project leader for consulting team assessing technical, achievable and economic potential for energy-efficiency and renewable resources in New York State and five sub regions over 5, 10 and 20 years, on behalf of New York State Research and Development Authority. (January 2002 – August 2003)

- Project leader for consulting team updating statewide projection of economically achievable efficiency potential for state of Vermont, on behalf of the Vermont Department of Public Service. (October 2001 – 2003)

- "A Conservation Contingency Plan for Indian Point: Using California's Success Beating Blackouts to Replace Nuclear Generation Serving Greater New York," prepared for the Natural Resources Defense Council, October 2003.

- "The Achievable Potential for Electric Efficiency Savings in Maine." Projected and compared 10-year C&I costs, savings and benefits (based on technical potential analysis prepared by Exeter Associates). Expert testimony on behalf of the Office of Public Advocate, before the Maine PUC. (October 2002)

- Project leader for consulting team supporting utilities in targeting demand-side resources to optimize distribution investment planning in statewide distributed utility planning collaborative, on behalf of the Vermont Department of Public Service. (September 2001 – December 2002) Led development of DSM scoping tool, an MS Excel spreadsheet for preliminary analysis of the economically achievable potential for energy-efficiency to defer or displace planned distribution investments.

- Advisor on economic analysis for program planning and implementation of multi-year statewide energy-efficiency programs in the New Jersey Clean Energy Collaborative involving all the state's electric and gas utilities and the Natural Resources Defense Council. (April 2000 – June 2003, on behalf of NRDC). Co-directed collaborative work on program development, planning, and implementation for Conectiv. (November 1996 – 2000)

- Policy and economic advisor for Massachusetts energy efficiency collaboratives, focusing on regulatory, cost-effectiveness, shareholder incentives and other policy issues and strategies, on behalf of Massachusetts Collaborative Non-Utility Parties. (January 1999 – present)

- Economic advisor to Northeast Energy Efficiency Partnerships, a not-for-profit regional consortium of utilities pursuing market transformation in efficiency markets. Economic analysis and report on cost-effectiveness of NEEP initiatives involving high-efficiency motors, clothes washers, and residential lighting. (1998 – in progress)

- "Examining the Potential for Energy Efficiency in Michigan: Help for the Economy and the Environment," for American Council for an Energy-Efficient Economy (ACEEE). Analysis and report projecting costs and benefits of aggressive energy-efficiency investment. (January 2003)

- Led consulting team in the preparation of detailed recommendations for implementing strategic plan for acquiring clean power resources for the Jacksonville Electric Authority. (May – September 2001)

- Consultant to Citizens Utilities Corporation, supporting planning and management of investments pursuing maximum achievable levels of optimally cost-effective energy-efficiency in its Vermont Electric Division. (1997 – 2001)

- Consultant to PEPCo Energy Services on building energy-efficiency into retail service offerings. (2000 – 2001)

- Consultant to California Board for Energy-Efficiency, the agency responsible for administering wires-charge funded statewide energy-efficiency programs. Technical service consultant on nonresidential program design. (1997 – 1999)

- Lead consultant on energy product development for consumer energy cooperative, on behalf of Vermont Energy Futures, a non-profit organization spearheading development of a consumer-owned energy cooperative that will bundle electricity with energy-efficiency, renewables, and fossil fuels for residential, low-income, and small non-residential customers. One of key team members who prepared grant application to federal Health and Human Services Department for $800,000 grant supporting development of the co-op. (1997 – 2000)

- Led feasibility analysis and prepared preliminary business plan for bundling electricity, fuel, efficiency services, and green power initially targeting low-income and environmentally-conscious consumers, on behalf of the Energy Coordinating Agency and Conservation Consultants, Inc. (July – December 1997). Consultant on energy and business strategy and planning for Energy Cooperative Association of Pennsylvania, a buyers' cooperative offering electricity, fuel oil, energy-efficiency, and renewable energy to residential and non-profit consumers in eastern and western Pennsylvania. (1998 – July 1999)

- Lead consultant on energy efficiency program designs and planning for Maryland Office of People's Counsel and Maryland Energy Administration. Led research, analysis, and program descriptions and budgets for use in restructuring workshops and legislative development on efficiency and renewable programs supported by system benefits charge. (1998)

- Consultant on various energy-efficiency program, planning, and policy issues for Maryland utilities including Potomac Electric, Baltimore Gas and Electric, Potomac Edison, Delmarva Power and Light, Southern Maryland Electric Cooperative, Washington Gas, on behalf of Maryland Office of People's Counsel. Coordinator and lead negotiator on DSM collaboratives for Washington Gas, Potomac Electric, Baltimore Gas and Electric, Delmarva Power and Light and Potomac Electric. Projects have included resource planning and allocation, program design, policy, cost recovery, mechanism design, and monitoring and evaluation planning. (1989 – 1997)

- Lead consultant for the Vermont Department of Public Service regarding energy-efficiency investment during and after the transition to electricity restructuring. Lead author of *The Power to Save: A Plan to Transform Vermont's Efficiency Markets*, the DPS filing which calls for development of centrally delivered statewide core programs by an efficiency utility. Prepared written testimony, on behalf of the Vermont Department of Public Service in Docket 5980. (1997 – 1999)

- Support to the Burlington (VT) Electric Department in developing energy efficiency programs and policies as part of their resource and business planning. (November 1996 – May 1997)

- Prepared written report to the Ontario Energy Board assessing the 1997 DSM Plan filed by Union and Centra Gas LTD in light of prior OEB decisions, as well as specific program plans for residential and non-residential customers. The report also addressed potential changes in gas DSM regulation, cost recovery, and incentives. [*Assessment of the Centra/Union Gas Fiscal 1997 DSM Plan*, Plunkett, Hamilton, and Mosenthal, August 30, 1996.] Also testified before the OEB concerning the report's findings and recommendations. Union/Centra Rate Case, EBRO 493/494. Also prepared a report and testified on Union Gas's DSM program design in EBRO 496/94/95. (July 1996 – November 1996)

- Support to the Iowa Office of Consumer Advocate with the review and analysis of MidAmerican's, Interstate Power's and Iowa Electric Services' existing energy efficiency plans. Developed proposals for changes to and modifications of the utilities commercial and industrial energy efficiency programs. (1995 – 1996)

- Prepared testimony and supported the Iowa Office of Consumer Advocate in settlement negotiations re IES Utilities C/I DSM programs. Docket No. EEP-95-1. (February 1996)

- Supported Florida Power Corporation with development of alternative DSM programs for commercial and industrial customers. (1995 – 1997)

- Supported the development of testimony and discussions regarding DSM program alternatives for Carolina Power & Light, on behalf of the Southern Environmental Law Center. Docket No. 92-209-E. (1995 – 1996)

- Reviewed and commented on Consumer Gas' C/I DSM programs on behalf of the Green Energy Coalition. (1995)

- Support to the Vermont Department of Public Service in negotiation settlement with Green Mountain Power regarding DSM program design and planning, focusing on target retrofits in load centers under T&D capacity constraints, and increased participation and comprehensiveness of lost-opportunity programs. (1995)

- Consulting services and expert testimony concerning Ontario Hydro's DSM plans and acquisition of lost-opportunity resources on behalf of the Green Energy Coalition. Before Ontario Energy Board H.R. 22. re: Ontario Hydro 1995 Rates and Spending. (1994) and re: Ontario Hydro's Bulk Power Rates for 1993. Ontario Energy Board HR-21. (1992)

- Coordinated testimony assessing the planning process, screening analyses, and cost-recovery proposals of the Detroit Edison Company for its demand-side management programs. Estimated potential levels of savings; identified improvements to the utility's proposed cost-recovery, lost-revenue, and incentive mechanisms; and recommended regulatory signals consistent with least-cost planning. Provided economic and regulatory advice, consulting services, and oversaw preparation of testimony. Michigan PSC Case No. U-10102. (1992)

- Economic and regulatory advice, consulting services, and oversaw preparation of testimony.

Provided technical services encompassing demand-side management program monitoring and evaluation, cost recovery, and review of second efficiency plans. Before the Iowa Utilities Board, Iowa Power and Light Docket No. EEP-91-3 and Interstate Power Company Docket No. EEP-91-5. (1992)

- Consulting on policy and resource-allocation issues on behalf of the Vermont Department of Public Service as part of DSM-program-design collaboratives with Vermont Gas. (1990 – 1991), Citizens Utilities (1990 – 1991), Central Vermont Public Service Corporation (1990) and Green Mountain Power. (1990)

ENERGY AND REGULATORY POLICY

- Team leader providing technical assistance supporting rulemaking to implement energy-efficiency provision of renewable portfolio standard for Pennsylvania, on behalf of Citizens for Pennsylvania's Future (PennFuture). Lead consultant on development of protocols for measuring savings from energy-efficiency investments as tradable credits toward the electricity resource portfolio standard. Protocols adopted by the Pennsylvania Public Utilities Commission. 2005. (February – September 2005)

- Analysis and testimony before the Connecticut Siting Council on integrating potential demand reductions from targeted demand-side resources into need assessment for transmission upgrades, on behalf of the Connecticut Office of Consumer Counsel. Docket No. 217. (February 2002 – present)

- Advice and negotiation on policy and scope of utility activities regarding targeted DSM to optimize distribution investment planning, involving Consolidated Edison, PECO Energy, and Orange and Rockland Utilities, on behalf of the Natural Resources Defense Council (Con Ed and PECO) and Pace Energy Project (O&R). (1999 – 2000)

- Consultant to Vermont Senate Natural Resources and Finance Committees on efficiency and renewable policies in restructuring legislation passed by the Senate but not adopted by the House. Provided technical assistance to support drafting and passage of utility restructuring legislation (S.62). (1997)

- Provided direct testimony and cross-examination relating to the future of DSM under the proposed BG&E/PEPCo utility merger. Case No. 8725 In the matter of Application of BGE, PEPCo & Constellation Energy Corporation for Merger. (1996)

- Reviewed Tennessee Valley Authority programs and environmental planning for the Tennessee Valley Energy Reform Coalition. (November 1994 – July 1995)

- Prepared and defended direct testimony on gas and electric Demand-Side Management/Integrated Resource Planning guidelines before the North Carolina Public Utilities Commission. Evaluated DSM activities in light of market barriers, total-resource-cost-effectiveness, and rate impacts. Docket No. E-100, SUB 64A in the matter of Request by Duke Power Company for Approval of a Food Service Program, Docket E-100, SUB 71 In the matter of Investigation of the Effect of Electric IRP and DSM Programs on the Competition Between Electric Utilities and Natural Gas Utilities. (1994)

- Prepared and defended expert testimony and led analyses of demand-side management and fuel switching opportunities in Central Vermont Public Service territory, on behalf of the Vermont Department of Public Service. Project involved detailed analysis of measure costs, savings, and cost-effectiveness. Vermont Public Service Board, Docket 5270-CVPS-1&3. (1994)

- Prepared and defended expert testimony for the Vermont Department of Public Service on prudence of demand-side management in CVPS rate case. Vermont Public Service Board, Docket 5724. (May – August 1994)

- Directed and supported the preparation of joint testimony for Enersave, an efficiency service provider. Before the New York Public Service Commission, Case No. 94-E-0334. (September 1994)

- Joint testimony with Jonathan Wallach for the New York Public Utility intervenors reviewing 1994 LILCo DSM Plan. Before the New York Public Service Commission. P.S.C. Case No. 93-5-1123. (May 1994)

- Contributed to the critique of PECO Demand-Side Management Plan for the Nonprofits Energy Savings Investment Program. (February 1994)

- Provided direct testimony in a proceeding to investigate restrictions on DSM that could give one utility (gas or electric) an unfair competitive advantage over another (electric or gas, respectively). Before the Louisiana Public Service Commission Docket No. U-20178 Re: Louisiana Power & Light Company Least Cost Resource Plan. (1994)

- Provided expert testimony in support of PEPCo's DSM implementation. Before the Public Service Commission of the District of Columbia. Case No. 929. (1993)

- Comprehensive assessment of Ontario Hydro's 25-year resource plan. Directed work by over a dozen consultants. The study encompassed load forecasting; assessing DM potential and costs; resolving DM-implementation, resource-integration, and institutional issues; assessing all resource costs, including externalities; assessing costs of all supply resources, including non-utility generators; and estimating avoided costs. (1990 – 1992)

- Support to the Pennsylvania Energy Office in its evaluation of Pennsylvania electric utility demand-management plans by preparing testimony and co-authoring a comprehensive, five-volume study of all aspects of demand management. This document surveys issues related to integration of demand-management resources into utility planning, and reconciling least-cost planning objectives with rate-impact constraints; discusses strategies for utility intervention to remove market barriers to energy conservation; evaluates cost-recovery mechanisms for demand-management expenditures by utilities; explores issues related to the screening demand-management measures and programs; and examines direct costs, risk, and externalities avoidable through demand management. (1991 – 1993)

- Provided analysis of 1991 - 1992 New York electric utility DSM plans, and support for the analysis of 1993 - 1994 DSM Plans on behalf of Pace University Center for Environmental and Legal Studies, and Vladeck, Waldman, Elias & Engelhard, P.C., Counsel for the Class of LILCo Ratepayers in County of Suffolk *et al.* v. LILCo *et al.* Proceeding to Inquire into the

Benefits to Ratepayers and Utilities from Implementation of Conservation Programs that will reduce Electric Use, New York Public Service Commission Case No. 28223. (1990, 1992, 1994)

- Reviewed Demand Side Management regulations and DSM compliance filings of four New Jersey utilities on behalf of the New Jersey Division of Rate Counsel. Demand Side Management Resource Plan of Jersey Central Power & Light Company. Docket No. EE-92020103. (1992)

- Advisor to the Vermont Public Service Board. Supported formulating issues, conducting hearings, deciding policy, and drafting opinions and orders on DSM planning programs, and ratemaking. Advised the Board's hearing officer on numerous decisions concerning policy and process, including cost-benefit analysis, design and coverage of utility energy-efficiency programs and integrated planning requirements. Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy, Docket No. 5270. (1988 – 1990)

- Provided technical and policy advice for the South Carolina Department of Consumer Affairs in PSC investigation into Electric Utility Least-Cost Planning, Docket No. 87-223-E. (September 1987 – November 1992)

RESOURCE PLANNING AND ASSESSMENT

- Support to the Vermont Department of Public Service in assessing the performance and expenditures of Green Mountain Power's commercial and industrial DSM programs. Also provided support to the DPS in the evaluation of GMP's actions surrounding the Vermont Joint Owners contract with Hydro Quebec including prudence. (1997)

- Prepared testimony and supported settlement negotiations concerning the DSM Plan of Jersey Central Power and Light on behalf of the Mid Atlantic Energy Project and New Jersey Public Interest Research Group. Analyzed DSM policy and commercial and industrial programs. Docket No. EE9580349 In the matter of Consideration and Determination of Jersey Central Power and Light Company's Demand Side Management Resource Plan filed pursuant to N.J.A.C. 14:12. (1995)

- Prepared written testimony for the Maryland Office of People's Counsel analyzing potential for demand-side resources offset need for power for proposed coal-fired plant. Delmarva Power & Light Company Dorchester Power Plant Certificate of Public Convenience and Necessity. Maryland PSC Case No. 8489. (January 1993)

- Provided technical assistance and advice on behalf of the South Carolina Department of Consumer Affairs on all aspects of Integrated Resource Planning and DSM planning including cost-effectiveness tests for South Carolina PSC investigation into Electric Utility Least-Cost Planning, Docket No. 87-223-E. (1987 – 1992)

- Identified energy-efficiency resources missing from FPL's resource plan that could provide economical substitutes for proposed power supply option. Expert testimony also addressed environmental costs avoided by DSM. Florida PSC Docket No. 920520-EG, In Re: Joint

Petition of Florida Power and Light and Cypress Energy Partners, Limited Partnership for Determination of Need. (1992)

- Provided technical consulting services for the Indiana Office of Utility Consumer Counselor, including expert testimony. In the matter of the Petition of Indianapolis Power & Light Company for a Certificate of Public Convenience and Necessity for the Construction by it of Facilities for the Generation of Electricity and Submission and Request for Approval of Plan to meet future needs for Electricity. Cause No. 39236. (August 1991 – May 1992)

- Provided technical consulting services for the Indiana Office of Utility Consumer Counselor, including expert testimony. In the matter of the Petition of PSI Energy, Inc. Filed Pursuant to the Public Service Commission Act, as Amended, and I.C. 8-1-8.52 for the Issuance of Certificates of Public Convenience and Necessity to Construct Generating Facilities for the Furnishing of Electric Utility Service to the Public and for the Approval of Expenditures for such Facilities. Cause No. 39175. (June 1991 – February 1992)

- Testimony and surrebuttal for the Delaware PSC Staff. Before the Delaware Public Service Commission Staff, In the Matter of the Application of Delmarva Power & Light Company for Approval of 48 MW Power Purchase Agreement with Star Enterprise, PSC Docket No. 90-16. (January 1991)

- Prepared comments on IRP principles and objectives for the Southern Environmental Law Center. Commonwealth of Virginia State Corporation Commission Order Establishing Commission Investigation to Consider Rules and Policy Regarding Conservation and Load Management Programs, Case No. PUE900070. (1991)

- Prepared and defended expert testimony for the Indiana Office of Utility Consumer Counselor on potential for DSM to defer need for new generating capacity. Petition of Southern Indiana Gas and Electric Co. for Approval of Construction and Cost of Additional Electric Generation and for Issuance of a Certificate of Need Therefore, Indiana Utility Regulatory Commission, Cause No. 38738. (September 1989)

- Prepared and defended expert testimony for the Illinois Citizens Utility Board on adequacy of Commonwealth Edison's DSM efforts. Rulemaking Implementing Section 8-402 of the Public Utilities Act, Least-Cost Planning, Illinois ICC Docket No. 89-0034. (July 1989)

- Supported the Vermont Public Service Board with analysis, findings, and conclusions regarding the need for power based on potential DSM resources. Application of Twenty-Four Electric Utilities for a Certificate of Public Good Authorizing Execution and Performance of a Firm Power and Energy Contract with Hydro-Quebec and a Hydro-Quebec Participation Agreement, Docket No. 5330. (1989 – 1990)

- Cost-benefit analysis for the City of Chicago examining alternatives to the renewal of Commonwealth Edison's franchise. (1989)

- Advisor for the South Carolina Department of Consumer Affairs. Assessed costs and benefits of long-term power contract. In the Matter of Duke Power Company, Federal Energy Commission, Docket No. ER89-106-000. (January 1989 – March 1990)

- Analyzed and provided expert testimony on the economic potential for cost-effective DSM to substitute for capacity and energy from a combined cycle generating plant. Testimony. Application of Potomac Electric Power Company for Certificate of Public Convenience and Necessity for Station H, Maryland PSC Docket No. 8063 Phase II. (1988)

- Examined, compared, and recommended appropriate cost-effectiveness tests for the DSM portion of the Massachusetts Department of Public Utilities investigation into the Pricing and Ratemaking Treatment to Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities. Docket No. 86-36. (1988)

- Testimony for the District of Columbia on electric and gas utility least-cost planning. Application of the Potomac Electric Power Company for Changes to Electric Rate Schedules, D.C. PSC Formal Case 834 Phase II. (April and June 1987)

- Stood cross-examination for the Connecticut Division of Consumer Counsel to defend KEA's financial assessment of CL&P's ability to withstand Millstone 3 disallowance. Investigation into Excess Generating Capacity of Connecticut Light & Power Company, Connecticut DPUC Docket No. 85-09-12. (April 1986)

- Cross examination for the Connecticut Division of Consumer Counsel to defend financial and statistical model supporting KEA's findings of CL&P construction imprudence. Retrospective Audit of the Prudence of the Construction of Millstone 3, Connecticut DPUC Docket 83-07-03. (March 1986)

- Cross-examination for the Pennsylvania Office of Consumer Advocate, defended quantification of imprudence findings by O'Brien/Kreitzberg & Associates regarding PECO's construction management of the Limerick 1 project. Pennsylvania PUC v. Philadelphia Electric Company Docket R-850152. (February 1986)

- Prepared and defended direct and surrebuttal testimony for the Pennsylvania Office of Consumer Advocate critiquing utility conservation and cogeneration assumptions and presented alternative 20-year electricity sales projection. Pennsylvania PUC Limerick 2 Investigation Docket I-840381. (April 1985)

LOW-INCOME ENERGY PROGRAMS

- Technical advisor to the Public Utility Law Project of New York. Recommended economic principles for planning utility DSM investment for low-income customers in New York. Proceeding on Motion of the Commission to Determine Whether the Major Gas and Combination Gas and Electric Utilities Subject to the Commission's Jurisdiction Should Establish and Implement a Low-Income Energy Efficiency Program, Case 89-M-124. (1990).

RENEWABLE ENERGY

- Co-author (with J. Wallach) of *The Power Analyst*, integrated spreadsheet-based software for projecting the economic and financial performance of renewable and cogeneration projects, for the New York State Energy Research and Development Authority. Project manager, economic analysis. (1989)

- Technical and economic analysis of small-generator grid interconnection of seven New York electric utilities for the New York Energy Research and Development Authority. Project manager, economic analysis. (1983)

- Written testimony on behalf of the Alaska Public Interest Research Group implementing PURPA 210. Before the Alaska PUC. (1981)

- Written and oral testimony in oversight hearings on state implementation of PURPA 210. U.S House of Representatives Subcommittee on Energy Conservation and Power. (1981)

- Written and oral testimony in rulemaking for PURPA on behalf of the Institute for Local Self-Reliance, before the Federal Energy Regulatory Commission. (1979)

PUBLICATIONS/PRESENTATIONS

"Charting New Frontiers with Vermont's Deployment of Demand-Side Transmission and Distribution Resources," ACEEE National Conference on Energy Efficiency as a Resource, Berkeley, CA, September 27, 2005.

"Energy Efficiency and Renewable Energy Resource Potential In New York State: Summary of Potential Analysis Prepared For the New York State Energy Research and Development Authority", invited presentation to the National Academy of Sciences Committee On Alternatives to Indian Point, Washington, DC, January 2005.

"Estimating and Valuing Energy-Efficiency Resource Contributions: Toward a Common Regional Protocol," presented at the Northeast Energy Efficiency Partnerships conference on regional efficiency policy, November 2004.

"The Economically Achievable Energy Efficiency Potential in New England," presented at the Northeast Energy Efficiency Partnerships conference on regional efficiency policy, November 2004.

"Rewarding Successful Efficiency Investment In Three Neighboring States: The Sequel, the Re-Make and the Next Generation (In Vermont, Massachusetts and Connecticut)," (with P. Horowitz and S. Slote), 2004 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2004.

"Measuring Success at the Nation's First Efficiency Utility" (With B. Hamilton), 2002 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2002.

"New Jersey's Clean Energy Collaborative: Model or Mess?" (with D. Bryk and S. Coakley), 2002 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2002.

"Yes, Virginia, You Can Get There From Here: New Jersey's New Policy Framework For Guiding Ratepayer-Funded Efficiency Programs" (with S. Coakley and D. Bryk), *2000 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2000.

"Integrated Market-Based Efficiency and Supply for Small Energy Consumers: The Consumer Energy Cooperative" (with B. Sachs and E. Belliveau) *2000 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2000.

"Comprehensive Energy Services At Competitive Prices: Integrating Least-Cost Energy Services to Small Consumers through a Retail Buyer's Cooperative" (with B. Sachs), *1998 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 1998.

"Capturing Comprehensive Benefits from Commercial Customers: A Comparative Analysis of HVAC Retirement Alternatives" (with P. Mosenthal and M. Kumm), *1996 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 1996. 5.169.

"Joint Delivery of Core DSM Programs: The Next Generation, Made in Vermont" (with S. Parker), *1996 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 1996. 7.127.

"Retrofit Economics 201: Correcting Common Errors in Demand-Side Management Cost-Benefit Analysis" (with R. Brailove and J. Wallach) *IGT's Eighth International Symposium on Energy Modeling,* Atlanta, Georgia, April 1995.

"DSM's Best Kept Secret: The Process, Outcome and Future of the PEPCo-Maryland Collaborative" (with R. D. Obeiter and E. R. Mayberry), *Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings,* Monterey, California, August 1994. 10.199.

Louisville Gas and Electric Company. Invited to make presentation on commercial program design. March 10, 1994.

'DSM for Public Interest Groups,"Seminar coordinator and presenter. DSM Training Institute, Boston, Massachusetts, October 1993.

DSM Training Institute - *Training for Ohio DSM Advocates: Effective DSM Collaborative Processes.* Seminar co-presenter. Cleveland, Ohio, August 1993.

"Demand-Management Programs: Targets and Strategies," Vol. 1 of "Building Ontario Hydro's Conservation Power Plant" (with J. Wallach, J. Peters, and B. Hamilton), Coalition of Environmental Groups, Toronto, ONT, November 1992.

"DSM Program Monitoring and Evaluation: Prospects and Pitfalls for Consumer Advocates," *Proceedings from the Mid-Year NASUCA Meeting,* Saint Louis, Missouri, June 8, 1993.

"Twelve Steps To Comprehensive Demand-Management Program Development: A Collaborative Perspective", *Proceedings from the IRP Workshop: The Basic Landscape, NARUC-DOE Fourth IRP Conference,* Burlington Vermont, September 1992. 45.

"Demand-Side Cost Recovery: Toward Solutions that Treat the Causes of Utility Under-

Investment in Demand-Side Resources" (with P. Chernick), *Proceedings from the Third NARUC Conference on Integrated Utility Planning*, Santa Fe, New Mexico, April 1991.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy?" (with P. Chernick and J. Wallach), *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference*, Columbus, Ohio, September 1990.

"Where Do We Go From Here? Eight Steps for Regulators to Jump-Start Least-Cost Planning" (with M. Dworkin), *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference*, Columbus, Ohio, September 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with P. Chernick) *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference*, September 1990. Also published in *Proceedings from the Canadian Electric Association's Demand-Side Management Conference*, St. John, Nova Scotia, September 1990.

"Carrots and Sticks: Do Utilities Need Incentives to Do the Right Thing on Demand-Side Investment?", *Proceedings from the National Association of State Utility Consumer Advocates* Santa Fe, New Mexico, June 1990.

"New Tools On the Block: Evaluating Non-Utility Supply "Opportunities with the Power Analyst" (with J. Wallach), *Proceedings from the Fourth National Conference on Microcomputer Applications in Energy*, Phoenix, AZ, April 1990.

"Breaking New Ground in Collaboration and Program Design," *The Rocky Mountain Institute Competitek Forum* (Moderator), Aspen, Colorado, September 1989.

"Lost Revenues and Other Issues in Demand-Side Resource Evaluation: An Economic Reappraisal" (with P. Chernick), *1988 Summer Study on Energy Efficiency in Buildings*, American Council for an Energy Efficient Economy, Pacific Grove, California, September 1988.

"Pursuing Least-Cost Strategies for Ratepayers While Promoting Competitive Success for Utilities", *Proceedings from the Least-Cost Planning Conference, National Association of Regulatory Utility Commissioners*, Aspen, Colorado, April 1988.

"Balancing Different Economic Perspectives in Demand-Side Resource Evaluation", Workshop on Demand-Side Bidding, Co-sponsored by New York State PSC, ERDA, and Energy Office, Albany, New York, March 1988.

"There They Go Again: A Critique of the AER/UDI Report on Future Electricity Adequacy through the Year 2000" (with C. Komanoff, H. Geller and C. Mitchell), Presentation NASUCA (also debated AER/UDI co-author before NARUC annual meeting), New Orleans, Louisiana, November 1987.

"Saying No to the No-Losers Test: Correctly Assessing Demand-Side Resources to Achieve Least-Cost Utility Strategies", *Proceedings from the Mid-year NASUCA meeting*, Washington, D.C., June 1987.

"The Economic Impact of Three Mile Island" (with C. Komanoff), *Proceedings from the American Association for the Advancement of Science symposium*, May 1986.

"Facing the Grid" (with D. Morris), *New Shelter*, May - June 1981.

Energy Efficiency Portfolio Performance Comparison

Nonresidential		Spending Depth (4) / (5)	Savings Yield (6) / (4)	Savings Depth (6) / (5)	Data		
State	Year	(1) $ Spent (2005$) per Retail Sector MWh Sales	(2) Annual kWh Savings per $ Spent (2005$)	(3) Annual MWh Savings per Retail Sector MWh Sales	(4) Spending (Nominal $ millions)	(5) Retail Sector Sales (MWh)	(6) Annual MWh Savings
Connecticut	2004	$1.5	5.7	0.76%	$23.4	16,779,631	127,385
	2003	$1.2	6.1	0.63%	$18.6	16,756,800	105,700
	2002	$1.7	5.1	0.73%	$26.2	16,622,278	122,036
	2001	$1.7	5.5	0.76%	$26.1	16,867,301	128,200
Efficiency Maine	2004	$0.3	6.4	0.17%	$2.0	7,462,290	12,338
	2003	$0.1	8.5	0.05%	$0.5	7,462,290	3,909
	2002	-	-	-	NAV	NAV	NAV
	2001	-	-	-	NAP	NAV	NAP
Massachusetts	2004	$3.4	3.2	1.10%	$68.6	19,173,983	210,152
	2003	$2.9	4.7	1.18%	$56.2	21,030,110	247,488
	2002	$3.4	3.5	1.02%	$63.4	20,247,516	205,856
	2001	$3.4	5.2	1.44%	$60.5	19,728,983	284,286
New Hampshire	2004	$1.3	5.7	0.65%	$7.6	6,457,719	41,879
	2003	$1.2	6.7	0.70%	$6.9	6,241,509	43,412
	2002	-	-	-	NAV	NAV	NAV
	2001	-	-	-	NAP	NAV	NAP
New Jersey	2004	$0.7	7.8	0.50%	$27.2	32,295,198	204,144
	2003	$0.7	7.6	0.48%	$27.6	41,105,248	197,347
	2002	$0.9	4.5	0.32%	$35.4	45,129,424	144,635
	2001	$0.3	2.9	0.07%	$11.8	43,671,352	30,943
Long Island Power Authority (LIPA)	2004	$0.8	3.7	0.27%	$7.2	9,666,377	25,828
	2003	$0.9	2.8	0.22%	$7.9	9,593,209	20,884
	2002	$0.9	4.0	0.31%	$7.5	9,026,264	27,542
	2001	$0.9	3.0	0.22%	$7.3	9,002,154	19,510
New York State Energy Research and Development Authority (NYSERDA)	2004	$1.3	9.0	1.21%	$52.5	37,897,275	456,900
	2003	$0.6	12.3	0.69%	$24.7	41,500,182	284,500
	2002	$0.6	10.1	0.49%	$25.8	48,471,686	239,100
	2001	-	-	-	NAV	NAV	NAV
Efficiency Vermont	2004	$1.6	6.0	0.86%	$4.9	3,294,004	28,410
	2003	$1.9	5.7	0.93%	$5.4	3,069,837	28,453
	2002	$1.6	4.6	0.63%	$4.9	3,291,679	20,630
	2001	$1.3	5.5	0.56%	$3.8	3,293,986	18,572

Notes:

1. NAV = Information Not Available; NAP = Not Applicable (No Program)
2. 2001, 2002, 2003 and 2004 sector sales as reported by US EIA
3. Maine sales are from Bangor Hydro (2003), Central Maine Power (2004) and Maine Public Service (2002); in addition, all others are assumed to be 5% of these sales
4. U.S. Bureau of Labor and Statistics Consumer Price Index Inflation Calculator used to calculate present worth in 2005$
5. Connecticut programs were suspended for part of 2003
6. 2003 Connecticut savings are for United Illuminating only
7. New Hampshire annual savings = lifetime savings / assumed average 15 year measure life
8. Vermont data excludes Burlington Electric Department

Energy Efficiency Portfolio Performance Comparison

Residential		Spending Depth (4) / (5)	Savings Yield (6) / (4)	Savings Depth (6) / (5)	Data		
State	Year	(1) $ Spent (2005$) per Retail Sector MWh Sales	(2) Annual kWh Savings per $ Spent (2005$)	(3) Annual MWh Savings per Retail Sector MWh Sales	(4) Spending (Nominal $ millions)	(5) Retail Sector Sales (MWh)	(6) Annual MWh Savings
Connecticut	2004	$1.4	5.1	0.65%	$16.4	12,366,484	80,617
	2003	$1.2	1.9	0.20%	$14.4	12,331,116	25,000
	2002	$1.7	4.3	0.62%	$18.3	11,772,238	72,460
	2001	$2.0	5.1	0.81%	$20.2	11,446,846	92,550
Maine	2004	$0.4	4.0	0.13%	$1.5	4,359,020	5,580
	2003	$0.1	4.6	0.04%	$0.4	4,359,020	1,918
	2002	-	-	-	NAV	NAV	NAV
	2001	-	-	-	NAP	NAV	NAP
Massachusetts	2004	$3.3	4.3	1.29%	$51.7	16,430,880	211,781
	2003	$2.3	2.8	0.55%	$34.6	16,114,567	88,913
	2002	$1.8	2.3	0.36%	$25.9	15,522,546	55,241
	2001	$2.2	2.5	0.45%	$30.1	15,159,987	68,291
New Hampshire	2004	$1.7	2.3	0.35%	$6.9	4,218,015	14,896
	2003	$1.7	2.2	0.32%	$6.5	4,129,405	13,344
	2002	-	-	-	NAV	NAV	NAV
	2001	-	-	-	NAP	NAV	NAP
New Jersey	2004	$1.5	3.5	0.46%	$37.4	26,947,140	124,369
	2003	$1.5	2.6	0.33%	$36.7	26,384,718	88,230
	2002	$1.1	1.0	0.09%	$26.8	26,598,261	24,161
	2001	$1.0	1.1	0.09%	$23.0	24,783,958	22,882
Long Island Power Authority (LIPA)	2004	$2.0	2.8	0.51%	$16.1	9,182,520	43,312
	2003	$2.7	2.7	0.64%	$21.8	8,489,702	54,742
	2002	$2.8	2.3	0.54%	$21.6	8,489,702	46,102
	2001	$2.4	2.7	0.52%	$17.3	8,143,069	42,574
New York State Energy Research and Development Authority (NYSERDA)	2004	$1.4	1.9	0.24%	$44.8	33,582,007	80,900
	2003	$0.7	3.3	0.19%	$20.3	33,260,213	62,700
	2002	$0.6	3.5	0.17%	$17.9	33,305,596	57,800
	2001	-	-	-	NAV	NAV	NAV
Vermont	2004	$3.6	4.3	1.44%	$7.0	2,016,715	29,026
	2003	$3.4	3.3	0.99%	$6.1	1,917,142	18,969
	2002	$3.2	3.8	1.02%	$5.7	1,955,203	19,991
	2001	$2.7	4.4	0.99%	$4.7	1,919,617	18,917

Notes:

1. NAV = Information Not Available; NAP = Not Applicable (No Program)
2. 2001, 2002, 2003 and 2004 sector sales as reported by US EIA
3. Maine sales are from Bangor Hydro (2003), Central Maine Power (2004) and Maine Public Service (2002); in addition, all others are assumed to be 5% of these sales
4. U.S. Bureau of Labor and Statistics Consumer Price Index Inflation Calculator used to calculate present worth in 2005$
5. Connecticut programs were suspended for part of 2003
6. New Hampshire annual savings = lifetime savings / assumed average 15 year measure life
7. Vermont data excludes Burlington Electric Department

Exhibit PF-JP-3

Range of Energy-Efficiency Portfolio Spending and Savings Expected for Duquesne Light
Based on 2002-2004 Portfolio Performance in Selected Jurisdictions

	Average 2002-2004		Duquesne Light						
				2007-2009 Projections					
					Average Annual Energy-Efficiency Electric Savings				
	Spending Depth	Savings Yield	Projected 2007 Sales	Average Annual Energy-Efficiency Budget	Energy Savings	% of 2007 Sales	Three-Year Total Energy-Efficiency Budget	Three-Year Total Energy-Efficiency Electric Savings
Jurisdiction	$ Spent (2005$) per Retail Sector MWh Sales	Annual kWh Savings per $ Spent (2005$)	GWh	2005$ (thousands)	MWh		Nominal $ (thousands)	MWh
Maine 2003-2004								
Residential	$0.23	3.74	4,054	$ 931	3,487	0.09%	$ 3,010	10,460
Commercial/Industrial	$0.18	6.20	10,146	$ 1,781	11,045	0.11%	$ 5,755	33,135
Total			14,200	$ 2,712	14,532	0.10%	$ 8,765	43,595
New Jersey 2002-2004								
Residential	$1.34	2.21	4,054	$ 5,445	12,008	0.30%	$ 17,595	36,025
Commercial/Industrial	$0.81	5.67	10,146	$ 8,252	46,748	0.46%	$ 26,664	140,243
Total			14,200	$ 13,697	58,756	0.41%	$ 44,258	176,268
Massachusetts 2002-2004								
Residential	$2.47	2.99	4,054	$ 10,030	30,019	0.74%	$ 32,411	90,057
Commercial/Industrial	$3.32	3.31	10,146	$ 33,661	111,359	1.10%	$ 108,768	334,077
Total			14,200	$ 43,691	141,378	1.00%	$ 141,180	424,135

Exhibit PF-JP_4

New Jersey Clean Energy Portfolio - Statewide Actual Results - 2004				
data from NJ Clean Energy Programs Report - Submitted to NJ BPU May 6, 2005	**Spending Thousand $**		**Installed Savings (kW)**	**(MWh)**
Residential Programs				
Residential HVAC – Electric and Gas	$	15,564	13,065	15,499
Residential New Construction	$	21,736	14,869	4,551
ENERGY STAR® Products				
Maintenance	$	1,654	-	-
Room Air Conditioning	$	397	1,441	1,377
Lighting and Other	$	6,048	5,089	95,947
Home Energy Audit	$	350	-	-
Appliance Cycling	$	496	173,164	-
Residential Low Income				
Comfort Program	$	13,974	770	6,786
Senior Weatherization Pilot	$	292	50	209
Refrigerator Turn-In	$	16	-	-
STAC Evaluation	$	1	-	-
Home Performance with ENERGY STAR®	$	6	-	-
Sub-total Residential	**$**	**60,534**	**208,448**	**124,369**
Commercial/Industrial				
Commercial/Industrial Construction				
Commercial & Industrial Construction	$	3,902	6,380	31,538
Commercial & Industrial Retrofit	$	22,686	33,751	163,631
New School Construction & Retrofit	$	3,073	3,199	8,975
Pay for Performance	$	32	-	-
Special Studies/Pilot Studies	$	8	-	-
Cool Cities	$	2,429	-	-
Combined Heat and Power Incentives	$	32	-	-
EDA Programs				
Pubilc Entity Financing	$	56	-	-
Sub-total Commercial/Industrial	**$**	**32,219**	**43,330**	**204,144**
TOTAL ENERGY EFFICIENCY PROGRAMS	**$**	**92,753**	**251,778**	**328,513**

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00061346

Duquesne Light Company

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Sur-rebuttal of John J. Plunkett
On Behalf Of
Citizens for Pennsylvania's Future

August 15, 2006

Q: **Please State your name and business address.**

A: I am John Plunkett. I am a partner in the Green Energy Economics Group, 1002 Jerusalem Road, Bristol, Vermont 05443.

Q: **Did you submit direct testimony on July 7, 2006 in this proceeding?**

A: Yes, I did.

Q: **What is the purpose of your sur-rebuttal testimony?**

A: I respond to the rebuttal testimony submitted by Mr. Kalcic on behalf of the Small Business Advocate, and that of Mr. Baron on behalf of the Duquesne Industrial Intervenors and the Industrial Energy Consumers of Pennsylvania.

SBA

Q: **Is Mr. Kalcic correct in characterizing your recommendations regarding Duquesne's funding of energy-efficiency investment?**

A: No. Mr. Kalcic erroneously contends that requiring Duquesne to invest $44 million in energy efficiency investment would "hold Duquesne to a separate and distinct standard" that would conflict with the Alternative Energy Performance Standard (AEPS), (Kalcic rebuttal at 8).

Q: **Why do you dispute these contentions?**

A: First, there is no "separate and distinct" standard involved in requiring Duquesne to fund investments in energy efficiency that would lower the total cost of electric service to its customers. While I am not an attorney, I understand that all EDCs franchised in the Commonwealth carry an obligation to provide safe and reliable electric service at the lowest reasonable cost. As my direct testimony clearly establishes, the recommended efficiency investment portfolio would save electricity at costs well below the supply costs it would avoid.

Second, there is absolutely no "conflict" with the intent of Act 213. The AEPS establishes a minimum standard of performance. From my perspective, I do not see anything in the Act that leads me to believe that it precludes utilities from investing beyond the minimum requirements mandated in order to fulfill their obligations to consumers.

DII / IECP

Q: Why does DII witness Barron oppose your recommendation that the Commission require Duquesne to fund investments in cost-effective energy-efficiency?

A: Mr. Barron appears to objects to ratepayer-funded efficiency investment for three reasons:

1. Such investments do not guarantee a distribution of benefits precisely equal to the distribution of costs between and within individual customer classes, and would therefore be inequitable
2. Such investments are not cost-effective if customers wouldn't have made them on their own, i.e., without the programs, and would therefore presumably be economically inefficient
3. Most if not all of the supply costs avoided by the energy-efficiency investments would be from generation, whereas the costs of the

investments would be recovered through distribution rates, which would be inappropriate.

Q: Is there any merit to Mr. Barron's reasoning?

A: No, as I will explain, the Commission should disregard all three of Mr. Baron's objections. First, a well-designed energy-efficiency portfolio will offer all customers the opportunity to take advantage of the services and incentives provided. While Mr. Baron is correct that I did not recommend a particular allocation of efficiency portfolio costs between classes, this is not a valid reason for forfeiting the benefits of the portfolio. The manner in which portfolio costs are recovered is one of the many important details that can and should be worked out later, preferably as part of the collaborative design process I recommend in my direct testimony. Such a draconian standard of distributional equity would preclude all sorts of utility investments routinely made by and expected of utilities such as Duquesne. For example, this logic would prevent Duquesne from making investments to improve reliability of its distribution system in some areas merely because all customers' service would not be made equally reliable at the same time.

Second, Mr. Baron conflates the individual investment decision-making of customers with the economics of utility supply investment decisions. Mr. Baron is correct that industrial customers – indeed all customers – have their own unique investment criteria. It is well established that these criteria tend to be much more restrictive with regard to saving energy than the cost-effectiveness criteria utilities employ when making transmission, distribution, and generation investments on behalf of these same customers. These more stringent customer requirements are understandable and rationale given the pervasive array of market barriers standing in the way of investments that save electricity for far less than the cost of supplying it. There is ample, indisputable evidence that well-designed and well-executed efficiency programs can overcome these barriers, making efficiency investments highly attractive to all kinds of customers – especially including large industrial users, for whom the potential for saving electricity for less than it costs to produce and deliver it is abundant.

Finally, it would be a serious mistake for the Commission to embrace Mr. Baron's apparent proscription against distribution investments that save generation costs. Such a policy would preclude distribution investments that reduce line losses, such as reconductoring to increase voltage. Such investments, which often make up a significant portion of EDC capital budgets, have as one of their primary benefits the reduction of generation costs incurred by customers Duquesne serves as the POLR.

Q: Does this complete your sur-rebuttal testimony?

A: Yes.

STATE OF PENNSYLVANIA

BEFORE THE PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	**Docket No. 00061346**
Duquesne Light Company	)	

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PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Citizens for Pennsylvania's Future

Statement 3

Direct Testimony of Paul L. Chernick

July 7, 2006

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TABLE OF EXHIBITS

I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further detailed in Exhibit PLC_quals.pdf, attached hereto.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately two hundred times on utility issues before various regulatory, legislative, and judicial bodies in the United States and Canada. These testimonies are listed in my resume.

Q: Have you testified previously on utility rate design issues?

A: Yes. Since 1978, I have testified approximately twenty times on rate design, including time-of-use and real-time pricing.

Q: Have you testified previously before the Pennsylvania PUC?

A: Yes. I testified in the following cases:

- Docket R-842651 on costs and cost-recovery for Susquehanna 2,
- Docket R-850152 on costs and cost-recovery for Limerick 1,
- Docket R-850290 on Philadelphia Electric Auxiliary Service Rates
- Dockets I-900005, R-901880 on DSM cost recovery mechanism

In various proceedings, I testified on behalf of the Pennsylvania Consumer Advocate, the Utility Users Committee, the University of Pennsylvania, Albert Einstein Medical Center, AMTRAK, and the Pennsylvania Energy Office.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by Citizens for Pennsylvania's Future (PennFuture).

Q: What is the purpose of your direct testimony?

A: I have been asked to recommend a policy for Duquesne's implementation of real-time pricing and other time-dependent pricing.

Q: What is the purpose of time-dependent pricing?

A: There are at least four categories of benefits from time-dependent pricing:

- If customers are given incentives to reduce energy use at the times when energy is most expensive, they can reduce the costs of their energy use and their energy bills.
- Reducing customer usage in high-price, high-load periods will tend to reduce capacity requirements to the customer's power supplier (Duquesne or a competitive supplier), and hence generation capacity costs. These costs may become much larger, depending on the outcome of on-going negotiations and litigation at FERC over PJM's rules for setting capacity prices and requirements.
- Reducing customer consumption at high-load periods will tend to reduce critical loads on the transmission and distribution systems and hence the cost of those systems.
- Reducing energy loads will tend to reduce market prices, resulting in lower energy bills for all consumers in the region.

Q: Are all time-dependent rate designs equally capable of reflecting the variation in costs?

A: No. Prices for any time interval vary unpredictably, so no fixed time schedule can reflect the actual variation in prices. In order to give customers accurate price signals, the prices must change to reflect conditions on an hourly or daily basis. To the extent feasible, load must be metered and priced on the same basis as market prices change; that is, hourly.

The technology for market-responsive metering will generally include remote-reading technology, reducing the costs of meter-reading.

Q: What actions should the Commission take in this proceeding?

A: The Commission should establish a policy of providing all customers with the most responsive metering system justified by the level of the customer's load and potential for load-shifting. Since all of Duquesne's large commercial and industrial customers already have hourly real-time meters, Duquesne should be cost-effective real-time pricing programs for its larger customers in the small-commercial, medium commercial-industrial and residential classes. These programs would include:

- Comparing the costs of metering, controls and communication equipment with the possible savings to participants and non-participants from reduced consumption of high-cost energy, reduced capacity requirements, and from reductions in market prices due to reduced load levels.
- Installing metering and associated equipment for customers whose size appears to justify the additional costs.

- Designing delivery rates to take advantage of the improved metering and reflect the varying contributions to peak transmission and distribution loads.
- Designing POLR rates to use the improved metering and reflect varying energy costs and contributions to generation capacity requirements.
- Collecting analyzing data on price response to monitor the effectiveness of the program design and identify (and correct) problems promptly.

Q: What can Duquesne do to improve participation and customer response in time-dependent pricing programs?

A: Duquesne should develop:

- Real-time pricing rate designs appropriate to the size and sophistication of a range of customers.
- Effective education and marketing. Especially for companies too small to have staff dedicated to power procurement, it is vital that the utility explain the benefits to potential participants and get the attention of senior management.
- A simple, effective system to assist customers in managing price risk and hedging costs, without damping incentives to conserve or shift load at times of high costs.
- Methods for providing participants with data on their hourly usage, so they can modify usage patterns and understand their bills.

Q: Is this an appropriate time for Duquesne to expand its real-time pricing offerings?

A: Yes. Duquesne's current POLR supply contracts run through 2007. At some point in 2007, Duquesne will need to contract for new POLR supply. By that time, Duquesne should have designed new real-time rates, estimated the number of customers for whom the rates would be cost-effective, started parallel billing for some of the eligible customers, and have some preliminary results on the response of customers to real-time rates. Those preparations would allow Duquesne to solicit POLR bids consistent with the rate designs, in terms of the number and timing of fixed periods and the time and pricing of market-responsive rates.

III. Options for Time-Dependent Pricing

Q: How can prices be set on a time-dependent basis?

A: There is a whole spectrum of time-dependent pricing from time-of-use at one end to real-time pricing (RTP) in 15 minute increments at the other. For example, utilities and competitive suppliers may implement:

- Traditional TOU with fixed prices over fixed period: California's experiment in real-time pricing includes a TOU rate with a fixed premium price for pre-determined critical peak hours.
- Critical peak pricing: In this approach, which California is also exploring, the timing of the critical hours is allowed to vary based on short-term (hour-ahead or day-ahead) conditions, but the premium price is fixed in advance. The critical hours may be determined by energy prices, load levels, or reliability of the supply and delivery systems.
- Variable peak pricing: The timing of the peak periods is fixed and the peak price is variable (essentially, the reverse of critical-peak pricing in reverse).

- Full real-time pricing: The price is set for every hour, typically based on market prices posted either the day before or on the real-time prices determined by the ISO in the hour.

Q: Should time-dependent rates reflect variability in all costs?

A: Time-dependent rates should vary, as much as feasible, with all the costs that vary over time. For generation supply, rates would ideally reflect variation of prices for energy and ancillary services, and varying contributions to determining the required generation capacity. Delivery rates should vary over time to reflect the likely contribution to peak loads and other critical conditions on the transmission and distribution systems.[1]

Q: Why is real-time pricing preferable to time-of-use pricing?

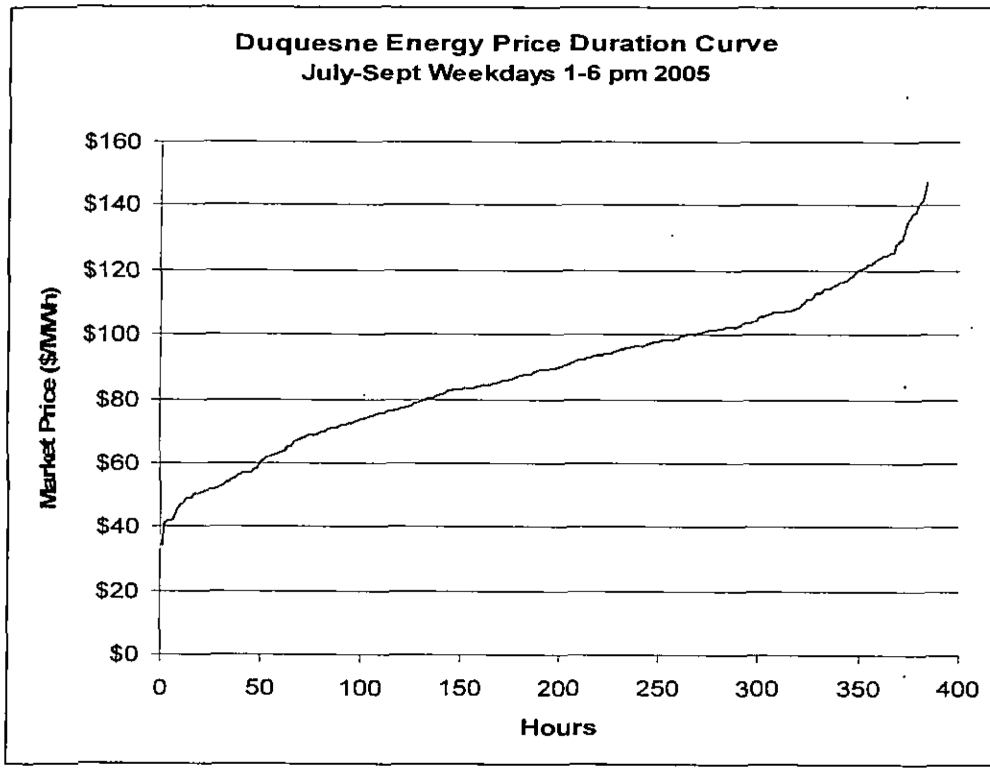
A: While energy costs tend to be higher in some months than in others, higher on weekdays than weekends, and higher at some hours than others, costs still vary widely within any pre-defined pricing period.

For example, for PJM's Duquesne pricing zone, prices were over $120/MWh in 35 weekday hours during July to September 2005, all between noon and 6 PM.[2] Prices in those hours averaged $129/MWh. In the same noon–6 PM hours in those three months, there were 349 hours with prices less than $120/MWh, averaging

[1]Allocating delivery costs as a function of load is more complicated and judgmental than observing market prices for energy, but imperfect time-differentiation of delivery costs is better than none.

[2] That is, in the hours ending 1 PM through 6 PM. One of these hours was on a Saturday.

$84/MWh. The prices were spread rather smoothly from about $65/MWh to $110/MWh, as shown in the following figure:



Thus, a time-of-use rate could not signal customers that power cost $147/MWh at 4 PM on September 22, and just $51/MWh at the same hour one week later, or $144/MWh at 5 PM on July 25 and $70/MWh on July 29.

Duquesne Market Energy Prices Over $120/MWh, Summer 2005

	Hour Ending					
Date	**13**	**14**	**15**	**16**	**17**	**18**
7/25/2005	$120	$129	$137	$141	$144	$138
7/26/2005		$124	$129	$123	$122	$124
8/4/2005				$124	$124	
8/8/2005					$121	
8/9/2005					$122	$122
8/12/2005					$125	$123
9/12/2005			$128	$135	$137	$133
9/13/2005			$125	$138	$142	$131
9/19/2005				$120		
9/22/2005		$128	$141	$147	$140	$123
9/23/2005		$125	$125	$121		
Hours >$120/MWh	1	4	6	8	10	7
other weekday hours	63	60	58	56	54	57
Average price						
on days >$120/MWh	$120	$127	$131	$131	$130	$128
on other weekdays	$76	$81	$86	$86	$88	$85

Q: How does real-time pricing benefit consumers in a restructured generation market?

A: There are three types of benefits. First, consumers on real-time pricing rates can save money in the short term, by reducing usage in the highest-priced hours. Second, all electricity users will benefit from improved reliability. To the extent that hours with low operating reserves tend to have high energy prices, even real-time pricing driven entirely by the energy will tend to reduce loads at the times that the bulk-power system is most stressed. Third, real-time pricing will tend to reduce market prices for energy and operating reserves, and perhaps capacity as well, depending on the eventual structure of the market. Fourth, line losses are highest at high load levels; reducing customer loads at high-load, high-price hours will reduce losses paid by all consumers. Fifth, transmission and distribution costs remain under cost-of-service regulation; reducing peak loads will tend to reduce the need for T&D additions and replacements, reducing T&D costs. Thus, both participating and non-participating Duquesne customers, and other Pennsylvania electric consumers, will benefit from appropriately-designed real-time pricing.

IV. Variable Delivery Charges in Real-Time Pricing

Q: Why should T&D costs be recovered through variable charges?

A: First, capacity limitations on Duquesne's T&D system generally occur in the summer. Therefore, the average kWh sold in peak periods, and especially during summer peak periods, result in higher transmission and distribution costs than energy sold in other periods.

Second, fixed charges are not an efficient way of recovering delivery costs. Charging more for summer usage and less for winter and shoulder use may provide customers with more appropriate price signals than demand charges that are constant over the year. Shifting revenues onto the summer would increase customers' incentive to control summer loads that determine the need for distribution-system capacity.

Q: In what ways do summer peak loads affect T&D costs?

A: Most of the large and expensive distribution elements—substations, subtransmission lines, feeders—experience their peak loads in the summer. The capacity of distribution equipment is generally lower under the weather conditions of summer peak loads than winter peak load. The capacities of transformers and underground power lines are limited by the build-up of heat created by the electric energy losses in the equipment itself, and the equipment heats up faster when the air and soil are already warm. The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with summer peak conditions of high air temperatures, light winds and strong sunlight.

In addition to driving the sizing of equipment, summer energy use tends to shorten the life of lines and transformers by overheating and degrading the insulation.

While load in the peak hour for any particular piece of equipment is important, so are loads in other high-load hours around the peak, since they contribute to the heating that reduces the load-carrying capacity of the equipment in the peak hour. Even off-peak energy use during a heat wave will contribute to overloading and degradation, by keeping the equipment from cooling off overnight.

For the minority of distribution costs that are not driven by summer loads, extreme winter loads would drive most of the remaining costs.

For most portions of the distribution system—a line transformer serving by a few or dozens of customers, a feeder serving hundreds or thousands of customer, or a substation serving many thousands—an additional kWh of load in the summer will impose higher costs on the system than an additional in other seasons. Winter energy use, particularly on-peak use, imposes higher costs than shoulder usage.

Q: How do transmission costs vary among time periods?

A: While some transmission costs were incurred to tie large remote generators into the power grid, or to allow for economic exchanges of energy with other regions, peak loads are certainly a major driver of transmission costs. On a time-of-use basis, transmission costs should be allocated primarily to the summer peak period or to the highest-price period in real-time pricing approaches.

Q: Why are fixed (or demand) charges not well suited to recovery of distribution or other costs, particularly in rate designs that include time-dependent rates?

A: Demand charges are particularly inefficient means for giving price signals, for the following reasons:

- Demand charges are not generally very effective at reflecting costs. The customer's peak hour is not likely to coincide with the peak hour of the other customers sharing the equipment it uses: the secondary system, line transformer, primary tap, feeder, substations, sub-transmission lines, and transmission lines.
- Demand charges are not effective in shifting loads off high-cost hours, and may even cause customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.
- The sizing of transformers and underground lines is also driven by the energy use on the equipment in high-load periods, in addition to maximum hourly loads.
- Demand charges and limit customers' control over the size of their bills.

Most of these problems flow from the fact that demand charges are difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour. Some of the problems with demand charges result from (1) the diversity among customers' individual peak load measured by demand meters and (2) the differences between those peaks and the coincident demands on utility equipment that determine costs.

Q: Please explain the importance of the diversity of consumer peak demands.

A: The investment in distribution equipment depends in large part (although not entirely) on the peak load on that equipment. If demand charges measured the contribution of customers to the peak loads on the distribution equipment, they would be very useful in providing price signals. Unfortunately, they do not.

The diversity of demand among a group of customers results in a group peak demand that is less than the sum of customers' individual maximum demands. In general, utilities size plant to meet the group peak, not the sum of customers' individual maximum demands.

Q: What pricing signals do demand charges give to customers?

A: Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs.

Demand charges provide little or no incentive to control or shift load from those times which are off the customer's peak hours but which are very much on the distribution peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the transmission peak, or on the peak load hour of the utility or other load-serving entities serving Duquesne consumers.

Q: How should delivery costs be recovered in RTP rates?

A: All system, regional, substation and feeder costs should be transferred to on-peak energy charges. Demand charges may make sense for recovering the costs of equipment used only (or primarily) by a single customer, but they should rarely be used otherwise. The additional revenues currently collected through demand charges can instead be collected through peak-period energy charges. This will encourage reduction of usage in high-load periods, when transmission and distribution equipment is heavily loaded.

V. Effective Real-Time Pricing Design

Q: What factors are important in developing effective real-time rate designs?

A: The key issues in creating effective real-time pricing include

- Effective education and marketing.
- A simple, effective system to assist customers in managing price risk and hedging costs.
- Designing the real-time pricing rate design for each class, recognizing the level of complexity the customers can tolerate and the metering can support.
- Providing participants with data on their hourly usage, so they can modify usage patterns and understand their bills.

- Cost-effective design of RTP programs, comparing the costs of metering, controls and communication equipment with the savings to participants and non-participants from reduced consumption of high-cost power and from reduction in market price due to reduced load levels
- Collection and analysis of data on price response to monitor the effectiveness of the program design and identify (and correct) problems promptly.

Especially for companies too small to have staff dedicated to power procurement, it is vital that the utility explain the benefits to potential participants and get the attention of senior management.

Q: What is the point of hedging in a real-time rate design?

A: The objective of real-time pricing is to give customers clear signals regarding when to use power, or avoid using it, to allow customers to decide which load-reducing measures they are willing to undertake at any particular time, given the cost of purchasing power at that time. At the same time, it is not desirable to expose customers to the risks of price volatility and unexpectedly high prices. Hedging reconciles these two objectives.

Q: How can customers be hedged against price volatility, without destroying the real-time price incentives?

A: The basic principle is that the customer should be eligible for a pre-determined amount of energy (the baseline) at the hedged price and should pay the real-time price for consumption above that amount or receive a credit for using less than that amount. This principle can be implemented in two ways. For a customer with a baseline of H MWh at $$h$/MWh and an actual load of R MWh at $$r$/MWh real-time price, the bill can be computed as either by

- Charging the customer the real-time price for all its consumption ($r \times R$) and crediting the customer for the difference between the real-time and hedged prices for the baseline ($[r-h] \times H$), for a net cost of $r \times R - [r-h] \times H$.
- Charging the customer the hedged price for the hedged amount ($h \times H$), plus the real-time price for the difference between the actual and baseline consumption ($r \times [R-H]$), for a net cost of $h \times H + r \times [R-H]$.

The first approach follows the pricing of conventional third-party hedges, in which the customer purchases a commodity (such as natural gas) in the forward market and sells that supply into the market to moderate the cost of its actual service. The second approach may be easier to explain to smaller customers. In any case, the two approaches produce identical net costs.[3]

Hedging thus protects customers from price fluctuations, without damping incentives to conserve or shift load at times of high costs.

Q: How should the baseline amount of hedged energy be determined?

A: Various programs have used variations on one of two approaches: either the baseline is set automatically based on the customer's previous use, or the customer selects the baseline.

Customers in the medium commercial-industrial class may be able to deal with the complications of selecting the level and shape of energy supply they want

[3] Both price formulas simplify to $h \times H + r \times R - r \times H$.

to lock in. For smaller customers, the utility will need to apply some mechanism for automatically determining the baseline (such as the customer's average load in some earlier period). Baselines can be set at a fixed time (a year ahead or a month ahead), or the customer can be given several opportunities to select hedges. For example, Duquesne could post forward prices every season for peak and off-peak hours in each the following four seasons, based on supplier bids. Customers would have one day to nominate the MWh of energy per hour they wish to hedge at that time. For example, in late October 2007 Duquesne might post prices for winter 2007–08 (December–February), Spring 2008 (March–May), Summer 2008 (June–September) and Fall 2008 (October–November). Each customer could select the amount of forward energy it wishes to hedge for each of those periods; for all except winter 2007–08, the customers would have another hedging opportunity in January 2008.

Baseline quantities can vary by hour, or can be equal across the hours within each pricing period (e.g., on-peak, nights, and weekend daytime).

Q: How could Duquesne design the real-time pricing rate for each class to recognize the level of complexity the customers can tolerate?

A: Large customers, with staff dedicated to building operations and energy purchasing, can follow hourly (or even 15-minute) real-time price signals, and respond as appropriate. This category may include some large companies with multiple facilities, even if the individual customer accounts are modest. For example, a fast-food chain with twenty restaurants in the Duquesne territory (or in other parts of PJM West with real-time pricing) may be able to centrally monitor real-time prices and remotely control lighting and other loads at the individual locations. For such customers, tracking energy prices on the PJM web site would probably not be burdensome.

While full hourly real-time pricing is the theoretic ideal, many customers may be overwhelmed by the prospect of tracking hourly prices and deciding how to react to each change in price.[4] Two alternative approaches have been developed that preserve much of benefit of real-time pricing for mitigating the highest prices, while simplifying the rate design.

- Critical-peak pricing. This approach, which has been applied to residential and small commercial customers in California, includes fixed time-of-use prices for two or three periods, with a fixed super-peak rate (e.g., $0.50/kWh) activated at variable times as justified by market conditions. This approach simplifies the rate design and may find greater acceptance with customers, who only need to decide how they will respond to a few price levels. But it still provides powerful incentives for load reductions at times of high costs or reliability problems. Hedging can be automatic, with customers charged or credited the super-peak price for the difference between their usage at the time the super-peak is invoked and their usage at comparable times on similar days. Metering and billing can be simplified by the limitation of rates to three or four pre-defined rates, as opposed to a wide range of hourly prices.

[4] The metering may also be too expensive, compared to the potential load shifts of smaller customers.

- Variable-peak pricing. This approach, which has been advocated by the New England ISO, uses entirely fixed time-of-use periods, with fixed prices for all the periods except a super-peak period, for which the super-peak rate determined by market conditions. Customers would know that the really high retail rates would occur only in the super-peak period, and that a single super-peak price would be posted for each day. Thus, they could schedule routine activities to avoid the super-peak, and decide which additional usage reductions to undertake based on the daily price. If high energy prices reliably occur in a narrow time period (e.g., noon to 4 pm), this approach may capture most of the potential benefits of real-time pricing, while being easier for customers to understand and adapt to.

Q: How would expansion of real-time pricing by Duquesne affect retail competition in its service territory?

A: Expanded real-time pricing should enhance retail competition, in several ways. First, Duquesne should provide competitive suppliers with access to all the data collected from the advanced meters, and work with competitive suppliers to develop meter-reading protocols that maximize the value of the data to competitive suppliers in serving their customers. Second, competitive suppliers will be able to offer variants on the real-time pricing approach, which may be more attractive to some customers than Duquesne's rate design. Third, some customers may prefer to have less price variability, and may choose competitive suppliers to move to a time-of-use rate. Fourth, real-time pricing will tend to reduce market prices and price volatility, making competitive supply less risky and more attractive.

VI. Benefits and Costs of Real-Time Pricing

Q: Why should electricity prices vary from hour to hour and month to month?

A: Costs of energy supply vary from hour to hour; the contribution of loads to the need for generation, transmission and distribution capacity also varies from hour to hour. Hence, supplying usage at some times is much more expensive than supplying that usage at other times. If customers are charged the same price in every hour, they have no incentive to reduce usage at high-cost times, and total costs of supplying customer loads will be higher than necessary.

Q: What does real-time pricing provide that conventional time-of-use rates do not?

A: Time-of-use rates price generation at a fixed price averaged over hours within defined periods of time. Real-time pricing allows customers to respond to variation in peak market prices that is not reflected in the on-peak price of a TOU rate.

Q: What magnitude of peak reductions might be possible with simplified real-time pricing for small customers?

A: In California, critical-peak pricing reduced peak usage on the critical days in 2003 and 2004 by almost 16 percent, about 25 percent more than for time-of-use rates. Adding some enabling technologies, such as smart thermostats, increased the critical peak-period reduction to 27 percent.[5] While Duquesne results would vary

[5] "Final Report: Impact Evaluation of the California Statewide Pricing Pilot," prepared for California Energy Commission Working Group 3 by Charles River Associates, March 16, 2005, page 9.

with the size and type of customers, climate, price variability, and details of rate design, the potential appears to be significant.

Q: Would customers on real-time pricing benefit from lower costs?

A: Yes, if the program is properly designed, and the participating customers are properly chosen. Real-time pricing, in any variation, should be applied only to customers who are large enough that potential savings from their load responses could cover the incremental costs of the real-time metering.[6] The program should also include hedging and revenue-neutrality, so that the average customer who did not respond to the real-time price signals would experience no significant bill change. With that background, if a customer chooses to reduce its usage in high-cost hours, its bill would decline.[7]

Q: Can real-time pricing benefit customers who are not on the real-time rates?

A: Yes. Customer response to real-time pricing would tend to reduce a number of costs for all customers:

- Real-time pricing customers will tend to reduce their use in high-price hours, allowing the ISO to back out the most expensive generators, reducing market energy prices, and probably prices for operating reserves.

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[6] Some customers, such as traffic signals, will clearly not respond to real-time prices, and should not be transferred to more expensive metering.

[7] Some customers with particularly expensive load shapes have been imposing higher-than average costs on Duquesne and other customers. Those customers would experience some increase in their bills unless they change their usage patterns. Conversely, the customers whose load have been less expensive than average to serve would experience lower bills with real-time pricing, even before they respond to the pricing signals.

- By reducing loads at highest cost hours and when price spikes occur, real-time pricing will reduce the ability of generators to exercise market power.
- Whether real-time price signals are used to signal customers when loads are likely to increase generation requirements, or only to signal high energy prices, real-time pricing is likely to reduce loads at the peak hours that increase capacity requirements. Reducing capacity demand will tend to reduce the market price.[8]
- Similarly, whether or not real-time pricing targets hours of stress on the transmission and distribution, it will tend to reduce loads at those times. Reducing future transmission and distribution investments will tend to reduce rates for all customers.
- Reduced electric load will tend to reduce the upward pressure on natural-gas prices, reducing costs for all gas consumers.[9]

Q: What are the costs of real-time pricing?

A: The categories of costs are

- Metering, which can be as much as $586 for a full real-time meter capable of recording every hour's use independently, but is also reported to be less than

[8] The PJM capacity-pricing method is currently in litigation before FERC.

[9] See "Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies," Elliot, RN, et al, American Council for an Energy-Efficient Economy, Report E032, December 2003, and "Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis," Elliot RN and Shipley AM, ACEEE Report E052, April 2005.

$100 for meters that would be suitable for critical-peak pricing or variable-peak pricing, and perhaps full real-time pricing.[10]

- Basic communications, which may be by phone line or various wireless technologies, to allow daily reading of the meter and/or remote signaling of the meter of the timing of the critical peak period.
- Advanced communications and controls, including equipment to signal customers of the time or pricing of super-peak periods, or to remotely control customer equipment, such as resetting thermostats, interrupting water heaters, dimming lighting, or cycling cooling equipment. This can be the most expensive component of real-time pricing; these advanced features should be added only where (1) they are useful for data collection or demonstration projects, (2) they are likely to be warranted by customer response, or (3) where the customer is willing to pay for the feature.

[10] The $586 value is the price Duquesne currently charges for a real-time meter (IR CPF-I-42(e)). The price of less than $100 is reported in Jurgen Weiss (LECG, LLC), "Time-Based Rates in Vermont," Workshop on Smart Meters and Time-based Rates, Montpelier VT, March, 15, 2006; Chris King, eMeter Corporation, "Advanced Metering Infrastructure (AMI): Overview of System Features and Capabilities," presentation in California Energy Commission Demand Response Workshop, October 5, 2004; U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act*, February 2006, page 25.

VII. Duquesne Experience

Q: Does Duquesne have any time-dependent rates?

A: Yes. Duquesne's time-dependent tariffs are Rider No. 8—Fixed Price Service, and Rider No. 9—Hourly Price Service. Rider No. 8 will terminate in May 31, 2007.

Q: What customers are eligible for service under Rider No. 9

A: Rider No. 9 is the default rate for large commercial and industrial users, although they may choose to be served under Rider No. 8. No other customer classes are eligible for service under this tariff.

Q: Please provide a summary description of Rider No. 9

A: Rider No. 9 is a flow through of PJM real-time market charges (e.g. energy, capacity, ancillary services) (IR CPF-II-7). Rider No. 9 has the following features:

- The tariff does not allow the customer a baseline consumption that would be charged at a hedged price; the participant pays market price for all usage.The basis for the energy charge is thePJM locational marginal prices for the Duquesne Zone or Duquesne Residual Zone as applicable. The charges for capacity, determined from the PJM daily capacity market are a direct flowthrough of costs based on customers' coincident demands, not customer maximum demands.
- Delivery and any other costs are priced under the customer's standard rate (either GL, GLH, L or HVPS).

Q: Has Rider No. 9 been effective?

A: The Rider has attracted 91 active participants on Rider 9 and only 4 customers on Rider No. 8 (IR CPF-I-42(c), CPF-I-46(c-d)). However, despite customers' interest in Rider No. 9, the Company has not "collected detailed information nor conducted a detailed evaluation" of the response to hourly pricing (IR CPF-I-42(d, f)). And it has no future plans to analyze the cost-effectiveness of RTP on its system (Penn-I-40)

Q: What is your evaluation of Duquesne's efforts to implement RTP ?

A: Three of the most serious weaknesses are:

- Duquesne has no stake in improving its RTP program. It is not currently marketing the rate (IR Penn-I-36). It has no formal plans to expand the program (IR Penn-I-35). It has no plans to develop new RTP programs in the future (IR Penn-I-22). It has no plans to install additional hourly meters needed to provide market pricing to more customers. (IR Penn-I-35, 37).
- Duquesne's real-time price does not give participants time to respond to price. The Company should consider giving the customers the option of hour-ahead or day-ahead PJM prices, so that they could have some advanced notice of price swings.
- Since Rider No. 9 charges market price for all energy, it fully exposes participants to risk. Yet, Duquesne has not provided any risk management services, including hedging (IR PennFuture-II-7).

Q: What is Duquesne's rationale for its reluctance to expand real-time rates to other customers?

A: The Company seems to indicate that it has limited interest in aggressively pursuing any time-dependent rates, let alone real-time pricing. The Company is only "beginning to evaluate time-of-use and seasonal rates." The Company appears to believe that implementation of new time-dependent rates is not worthwhile until after its current POLR III plan expires at the end of 2007.

Q: Does Duquesne have a valid rationale for delaying implementation real-time pricing and other time-dependent rates until after 2007?

A: No. As explained above, preliminary estimates of the price-response to expanded real-time pricing and other new time-dependent rates should be available to Duquesne when it solicits POLR bids.

VIII. Conclusions and Recommendations

Q: What are your conclusions?

A: Real-time pricing, both as full hourly pricing (as in Duquesne's Rider 9) and in various simplified forms, has significant potential for reducing costs to customers and improving the efficiency of the competitive market. Compared to full hourly real-time pricing, simplified real-time pricing may be both less expensive and more acceptable to customers. These rate designs would benefit both participating and non-participating Duquesne customers, whether they are served by Duquesne POLR or competitive suppliers, as well as other Pennsylvania electric consumers.

Q: What are your recommendations?

A: My principal recommendation is that the Commission instruct Duquesne to expand its offerings of market-responsive rates, to include smaller customers. This process would include:

- Working with a workgroup of shareholders (e.g., PennFuture, OCA, OSBA and representatives of competitive suppliers) to evaluate the cost-effectiveness of alternative real-time metering and select appropriate metering options and protocols for sharing metering data with competitive suppliers.
- Working with PennFuture, OCA, OSBA and other advocates for residential and small to medium commercial and industrial consumers to develop alternative real-time rate designs for delivery and POLR rates, including POLR hedging mechanisms, effective education and marketing.
- Installing appropriate improved metering for all customer groups for which the metering appears to be cost-effective.
- Seeking approval from the Commission for new rate designs.
- Providing customers with bill comparisons between standard and real-time rates.
- Collecting load and cost data and performing rigorous evaluation of the results of the rate redesign.

Q: How should Duquesne recover the costs of these activities?

A: The Commission should order Duquesne to defer the incremental costs of studies, new meters and other equipment and projects required to implement effective real-time pricing. Duquesne should also track any operating-cost savings from the improved meters. Duquesne should report to the Commission every six months on actual expenditures and projected expenditures, as those are clarified.

The Commission should allow Duquesne to propose a mechanism for recovering the balance of the program costs, either by deferral until the next rate case or filing a reconciling rate adjustment, if necessary.

That concludes the testimony of Paul Chernick

Exhibit PLC-1

PAUL L. CHERNICK

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SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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EXPERT TESTIMONY

1. **MEFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **MEFSC** 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **MEFSC** 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27 1978.

Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. **MDPU** 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

STATE OF PENNSYLVANIA

BEFORE THE PUBLIC UTILITY COMMISSION

In the Matter of the Duquesne	)	Docket No. 00061346
Light Company Base Rate Case	)	

SURREBUTTAL TESTIMONY OF

PAUL L. CHERNICK

ON BEHALF OF

CITIZENS FOR PENNSYLVANIA'S FUTURE

Resource Insight, Inc.

AUGUST 15, 2006

TABLE OF CONTENTS

I. Introduction

Q: Did you submit direct testimony in this proceeding?

A: Yes.

Q: What is the purpose of your supplemental testimony?

A: I respond to real-time pricing and other rate design issues raised in rebuttal testimony sponsored by Duquesne, the Office of Trial Staff, and the Office of Small Business Advocate:

- Time-differentiated delivery charges are not appropriate (Pfrommer at 9).
- Real-time pricing is ineffective and burdensome for small business customers (Kalcic at 10).
- Higher customer charges do not reduce incentives to conserve (Gruber at 2).
- Elimination of declining block charges may have disruptive bill impacts. (Gruber at 3-4).

In addition, I respond to the Directed Questions of Vice Chairman Cawley.

II. Time-Dependent Rate Issues

Q: Why does Duquesne oppose time-differentiation of distribution charges?

A: In the Company's view, time-dependent and energy-based distribution charges should be rejected because (1) they do not serve the "primary goal of rate design [to] provide recovery of revenue requirement" and their implementation would increase business risk (Pfommer at 9) and (2) they do not reflect cost causation, because distribution costs do not vary with energy or time of use.

Q: Do you agree with the Company's arguments?

A: No. First, the Company's desire for revenue stability to the exclusion of all else is antithetical to the goal of conservation, cost-based rate design, and reduction of system costs.

Second, inexplicably, the Company rejects time-differentiated distribution rates, even though it clearly understands that on-peak demands in the summer are a significant driver of distribution costs.

Third, super-peak energy charges, not demand charges, best reflect costs that are driven by peak demands and energy. Transferring cost recovery off demand charges onto peak-period energy charges will encourage customers to reduce usage in high-cost, high-load periods, when transmission and distribution equipment is heavily loaded. I discussed this matter at length in my direct testimony.

Q: What is the basis for Mr. Kalcic's assertion that real-time pricing is not cost-effective or acceptable to customers?

A: First, Mr. Kalcic asserts that small business customers are unable to shift or reduce their load in response to real-time pricing:

> retail business must generally be conducted during normal business hours. For example, a restaurant is not in a position to switch its hours of operation from 11:00 am through 10:00 pm to, say, 6:00 pm through 5:00 am, just to avoid the bulk of PJM's on-peak period (Kalcic at 10).

Second, Mr. Kalcic cites the Company's claims that even large C&I customers dislike real-time pricing because (1) only 10% of Duquesne's large C&I customers had the financial ability and sophistication to administer it effectively, and (2) real-time pricing exposes to them to volatility and financial uncertainty.

Q: Does Mr. Kalcic provide sufficient support for his rejection of real time pricing?

A: No. There are a number of flaws in Mr. Kalcic's argument. First, the market-responsive rate designs should be appropriate to the size and sophistication of the customers. Full real-time pricing would not be applied to small commercial customers, because the potential savings from their load responses are unlikely to cover the real-time metering costs. A simplified real-time pricing, such as critical peak pricing (where the timing of the critical hours varies based on short-term conditions, but the premium price is fixed in advance) and variable peak pricing (where the timing of the peak periods is fixed and the peak price is variable), may be appropriate for small customers, or if not, a three-period time-of-use rate with a super-peak period with pre-established time periods and charges.

Second, Mr. Kalcic does not appear to understand how real-time pricing operates. He assumes that the restaurant must "switch its hours of operation from 11:00 am through 10:00 pm to, say, 6:00 pm through 5:00 am." In actuality, the periods with the highest energy costs and restricted capacity are much less frequent than Mr. Kalic assumes. If rates are designed with a narrow super-peak period that signal the highest cost hours, many small customers, perhaps even restaurants, would be able to shift load off the highest cost periods.

Third, some business customers are just as frustrated by existing fixed charges—demand charges and especially customer charges—that reduce their control over the size of their bills. Demand charges are particularly confusing, since the concept of charging for maximum hourly demand has little parallel in other commercial relationships.

Fourth, the Company can improve customer's ability to respond to market-responsive rates by providing an effective educational resources, providing information to the customer about its individual usage patterns, and assisting customers in managing price risk.

Q: Does Mr. Kalcic's description of Rate HPS experience demonstrate that real-time pricing is ineffective?

A: No, for two basic reasons. First, according to its response to discovery, the Company has not "collected detailed information nor conducted a detailed evaluation" of the response to hourly pricing (IR CPF-I-42(d, f)). Therefore, the Duquesne finding that only 10% of customers has not been documented.

Second, Duquesne's real-time pricing program has at least two serious design flaws that could discourage some participants:

- Duquesne's real-time pricing does not give participants time to respond to price. The Company should consider giving the customers the option of hour-ahead or day-ahead PJM prices, so that they could have some advanced notice of price swings.
- Rider No. 9 charges market price for all energy; therefore, it fully exposes participants to risk. Neither has Duquesne has not provided any risk management services, including hedging (IR PennFuture-II-7).

Q: Why does Mr. Gruber believe that shifting revenue recovery onto customer charges will not affect customers' incentives to conserve?

A: In Mr. Gruber's view, customers do not understand their rates and respond only to the total amount of their bill. Only with an "intensified customer education" program would customers realize that their savings from conservation depend on the size of the variable charges, not the total bill.

Q: Do you agree with Mr. Gruber's argument?

A: No. Mr. Gruber's argument assumes implausibly that customers are so ignorant that they will make even large energy-efficient investments without a careful evaluation of savings and will not notice when their conservation efforts fail to reduce their bills.

Q: Do you have any comments regarding Mr. Gruber's concern that eliminating declining block charges will have disruptive bill impacts and hurt the business environment?

A: Almost any rate-design change will increase the bills of some customers, at least in the short term. This is a reality that has faced the Commission in every rate-design decision it has ever made, including mandating TOU rates for large customers. In the longer term, better rate design should reduce total costs and may benefit virtually all customers.

If some customers with expensive-to-serve load shapes are harmed, others who are inherently less expensive to serve (and have been overcharged) will be helped by real-time pricing. Since customer response to properly designed market responsive rates should decrease total bills for Duquesne customers, and will certainly provide improved opportunities for customers who wish to control their bills to do so, the net effect should be fewer business closures, not an increase.

Finally, as with any rate design chane, the elimination of tail block charges can be phased in to limit disruptive bill impacts.

III. Directed Questions of Vice Chairman Cawley

Q: With respect to the first question, do fixed charges for residential and small or medium commercial customer distribution services discourage conservation of energy? If so, what other revenue decoupling models can be implemented that would optimally meet the dual needs of providing incentives for consumers to conserve energy, while providing reasonably stable revenues for utilities?

A: Yes, fixed charges for distribution services discourage conservation of energy, compared to recovering the same revenue through energy charges. The higher the portion of the bill recovered through fixed charges, the lower the energy charges, the less the customer saves from energy conservation, the lower the incentive to conserve. The effect on the level of energy charges is most pronounced for residential and small or medium commercial customers, where fixed charges tend to be the highest percentage of total distribution revenues.

Duquesne proposes a 50% increase in its residential rates in line with:

> [its] long-term plan ...to migrate toward rates that reflect the services provided by a delivery company that are more reflective of the way the transmission and distribution systems are designed and operated, and the way in which fixed costs are incurred. (Statement 12, p. 9).

The Company is incorrect.

Fixed charges are not appropriate vehicles for recovering most distribution costs, since many distribution costs vary with load levels and energy use. As discussed in my direct testimony on behalf of PennFuture (pp. 10-14), distribution costs are driven by a combination of:

- the coincident peak load on each piece of equipment.
- high short-term loads, even if they are below peak, because they contribute to the heating that reduces the load-carrying capacity of the equipment in the peak hour and keeps the equipment from cooling off overnight.
- energy use, especially on days with high peaks. Summer energy use tends to shorten the life of distribution equipment by overheating and degrading the insulation.

If the PUC wishes to decouple Duquesne's revenues from its sales level, the most direct way to do so would be to set up a decoupling mechanism (also frequently called a revenue adjustment mechanism or RAM). Typically, a RAM would consist of the following components, all set by the PUC:

- A base distribution revenue target for Duquesne, which might just be the revenue requirements established in this rate case.
- Rules describing how that target would change with various indices, potentially including customer number, inflation, and some measure of economic activity. The objective would be to approximate the revenues that Duquesne would normally expect to receive. In the short run, sales

and hence sales tend to increase with customer number, usage trends and the local economy.[1] In the longer term, inflation tends to increase utilities' costs, and they file rate cases.[2] If the PUC intends that the decoupling delay rate-case filings, perhaps as part of performance-based ratemaking, inflation may be a significant consideration. If the PUC is content with more frequent rate filings, inflation should probably not be reflected in the adjustments to the target. Decoupling will automatically provide a form of weather normalization; if the PUC wants to avoid that outcome, it can adjust the revenue target for actual weather.

- The conditions under which the decoupling plan would be terminated, which might include a severe economic downturn, or dramatic changes in energy use per customer.
- The rules for the computation of the RAM balance, including the time period of each computation (e.g., monthly, quarterly), whether the RAM will be computed by class or in total, and whether interest will accrue on the balance. The importance of interest will depend in large part on how long the balance is allowed to accrue.

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[1] Care must be exercised to accommodate the possibility that new customers are really incremental load, and not just the result of remetering master-metered loads, and that new customers in a class are very different from the existing customers.

[2] Distribution costs also decrease as depreciation accumulates, and increase as new equipment is added to accommodate growth and to replace older (typically less-expense) equipment as it is retired.

The PUC could determine in advance how the RAM balance would be rolled into rates (through a periodic rate adjustment or through deferral to the next rate case), or it can leave that issue to be determined once the magnitude of balance and other factors are known. For example, if power costs are high, and the RAM balance is positive (i.e., ratepayers owe the shareholders), the PUC might prefer to defer an adjustment. If the RAM balance is negative, the PUC may choose to flow it through in a time of high power costs, to moderate total bills. Or if power costs drop, that might be a good time to flow through a positive balance.

Proper design of a RAM is not simple. The PUC might decide in this docket to initiate a proceeding to develop a decoupling mechanism for Duquesne; attempting to develop the mechanism within a rate case is probably ill-advised.

Q: With respect to the second question, do declining block rate designs remove the incentive for consumers, especially RA and RH residential consumers and small to medium sized commercial and industrial customers ("C&I"), to conserve energy? If so, should declining block rates for supply and distribution services be phased out over time?

A: Yes. Declining block rate structures reduce incentives to conserve by providing discounts for tail block usage. Tail block usage on the Duquesne system will be heavily summer peaking because:

- The customers are more likely to be in the tail block in the summer than in the winter;
- The residential and small to medium-sized C&I customers who have usage in the tail block are most likely to have individual peaks (e.g, due to air conditioning) that coincide with system peak or distribution peaks. The smaller customers in these rate classes tend to have better load factors.

Duquesne's rates with declining blocks in the summer months should be phased out over time. The traditional rationale for declining block rates is that the larger customers in a rate class should pay less because they have a better load factor or are more off-peak. If there are larger customers in a rate class that do have a better load factor or are more off-peak, time-of-use rates would capture these cost differences more effectively.

Q: With respect to the third question, do demand based charges, and in particular demand based charges for default supply service, remove the incentive for consumers, especially small to medium sized C&I customers, to conserve energy? If so, should demand based rates for such customers be phased out over time?

A: Yes. Like customer charges, demand charges for distribution services discourage conservation of energy, compared to recovering the same revenue through energy charges. Demand charges are determined by the customer's individual maximum demand. Therefore, they provide customers with little or no incentive to conserve or shift load from those times which are off the hours of the customer's maximum demand but which are very much on the distribution peak hours. The Company recognizes that "[r]elatively higher demand charges may encourage load management load management, while a higher weight of energy charges may encourage conservation." (Pfrommer at 27).

Second, most distribution costs are driven not by individual customers' maximum demands but by a combination of:

- the coincident peak load on each piece of equipment
- high short-term loads, even if they are below peak, and
- energy use, especially on days with high peaks.

For these reasons, demand charges should be phased out of rates and replaced by time-of-use rates.

Q: With respect to the fourth question, can and should rate designs vary among customer classes? For example, larger industrial and commercial ("C&I") customers generally have a much smaller percentage of their revenues attributable to distribution services. Given this dynamic, does the commodity design of supply service rates provide adequate incentive for larger C&I customers to conserve energy?

A: If properly designed, the real-time market prices charged to large C&I customers under Rider 9, or the market-based price charged by competitive suppliers, will give large customers an incentive to conserve equal to the cost of market supply. The supply service charges do not include the incremental costs on the distribution system due to increased load. Hence, Duquesne's large C&I distribution rates should also be structured to reflect the contribution of load to the sizing and aging of distribution equipment, with most of the costs recovered through energy and coincident-peak charges, rather than fixed customer charges or demand charges driven by the customer's own peak. Some distribution equipment close to the large customer, and typically sized to accommodate the customer's load, might be charged on a non-coincident billing demand.

The fact that distribution charges are a smaller share of the bill for the large C&I customers than for smaller customers means that appropriate distribution rate design is less important for the larger customers, but there is no reason not to structure all rates as efficiently as practical.

This concludes the Sur-Rebuttal Testimony of Paul Chernick

St. No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY OF
FRANK P. LACEY

On Behalf of Direct Energy Services, LLC

Duquesne Light Company Base Rate Case
Docket No. R-00061346

July 7, 2006

I. INTRODUCTION

Q. COULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Frank Lacey. I am the Director of Government and Regulatory Affairs for Direct Energy Services, LLC ("Direct Energy"). My business address is 263 Tresser Boulevard, 8th Floor, Stamford, Connecticut 06901. I live in McMurray, Pennsylvania. Within Direct Energy, I am responsible for the development of the competitive retail energy markets in the Commonwealth of Pennsylvania and other areas of the country.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. My Curriculum Vitae is attached as Appendix A.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have testified as an expert in two prior cases before this Commission. I have also testified in two separate roundtable proceedings before the entire Commission. Additionally, I have testified as an expert in proceedings before the PUC of Ohio, and the California PUC. I have also testified before the Maryland, New York and Michigan state legislatures.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Direct Energy Services, LLC.

Q. WHO IS DIRECT ENERGY SERVICES, LLC?

A. Direct Energy is Direct Energy is an EGS licensed to provide electricity and related services to retail customers throughout Pennsylvania, including Duquesne's service territory. Direct Energy is a subsidiary of Centrica, a leading provider of energy and other energy-related services to over 20 million households worldwide, with annual revenues of $33 billion and $17 billion in market capitalization, and over 38,000 employees. Direct Energy has over 5 million gas and electricity customer relationships in North America. Direct Energy has extensive experience serving customers of all classes, including residential customers.

II. OVERVIEW OF TESTIMONY

Q. COULD YOU PLEASE OUTLINE YOUR TESTIMONY?

A. My testimony will focus primarily in three areas. First, I will show that Duquesne Light Company ("Duquesne" or "Duquesne Light" or "Company") is attempting through this rate case to collect a substantial amount of generation-related costs in its distribution rates. From a policy and legal perspective, these costs must be collected not in the Company's distribution rates but in the charge for generation-related service -- its Provider of Last Resort ("POLR") or default service rates. I will show how the pricing approach advocated by Duquesne not only overcharges Duquesne's distribution service customers but, if permitted to continue, will drive competition for electricity supply out of the Duquesne Light service territory, with the end result being the creation of a de facto monopoly incumbent service provider. I will then describe the steps that the Commission should take to remedy this problem. If the necessary changes in distribution and POLR rates are not made until Duquesne implements its POLR IV plan in 2008, I recommend a series of measures that will mitigate the anticompetitive effects of the cost subsidies that are presently embedded in Duquesne's distribution rates, subsidies that will be exacerbated if Duquesne's proposed rate increase is granted. I recommend that the Commission implement other competition enhancing steps including ordering Duquesne to purchase the receivables of participating EGSs and implementing an advanced metering installation program.

Q. COULD YOU PLEASE PROVIDE AN OVERVIEW OF THIS CASE FROM YOUR PERSPECTIVE ?

A. It has been many years since Duquesne Light last had a distribution rate proceeding. In that time, restructuring and retail choice have become the policy of the Commonwealth. During the period since restructuring has been implemented, Duquesne has had several proceedings in which its POLR rates have been set, but the Company has *not* revised its distribution rates. Since, for many reasons, revising a utility's distribution rates to remove POLR-related costs is most appropriately done in a distribution rate proceeding, Duquesne's POLR rates have not been able to be adjusted to reflect all costs incurred to provide this service. In Duquesne's previous POLR proceedings there has been dialog and testimony about the need for a "retail adder" to neutralize the competitive imbalance created by Duquesne Light not unbundling all of its generation-related costs from its distribution rates. A retail adder is not a solution to the retail choice issues of cross-subsidization and discrimination against retail suppliers resulting from this misallocation of costs. The best approach is to reset both distribution and POLR rates in order to reflect an appropriate allocation of the current costs of providing each of these separate services.

III. IMPORTANCE OF APPROPRIATELY ALLOCATING DISTRIBUTION COSTS

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT THAT COSTS OF PROVIDING POLR AND DISTRIBUTION SERVICE ARE ALLOCATED AND RECOVERED IN THE APPROPRIATE RATE ELEMENTS ASSOCIATED WITH THOSE COSTS.

A. There are several reasons. First, it is a basic rule of rate structure/cost allocation that the costs of providing a particular utility service should be assigned to the customers or services that are causing the costs. Duquesne has claimed to follow this principle generally by allocating its overall revenue requirement between its federally regulated services (*i.e.*, transmission) and its PA-jurisdictional services, and then to the various retail customer classes that Duquesne serves. For example, the Company's jurisdictional allocation study to remove transmission costs from this rate case attempts to remove all costs associated with providing transmission service, including a small portion of A&G -- joint and common costs -- from the distribution revenue requirement.[1] Presumably the Company recognized that it would be inappropriate to attempt to recover transmission related costs in its distribution rates.

It is also fundamental accounting practice to match expenses as closely as possible with associated revenues. This accounting principle is referred to as the Matching Principle. The Financial Accounting Standards Board and generally accepted accounting principles require that revenues and expenses associated with those revenues be matched to determine the profitability of a business.

Q. ARE THERE ANY OTHER REASONS FOR APPROPRIATELY ALLOCATING GENERATION RELATED COSTS?

A. Yes. It is important to accurately calculate the cost of generation in order to assure that customers will receive accurate signals regarding the cost of using an additional unit of energy. If POLR-related costs are placed in non-bypassable "wires" charge, customers will receive false signals concerning the cost of electric energy. In turn, they may make uneconomic decisions about investing in conservation or energy efficiency, or about their choice of generation supplier on the basis of a skewed understanding of how much they are really paying for the electricity commodity.

By the same token, if POLR costs are recovered in Duquesne's distribution rates, distribution customers could easily pay too much or too little for the distribution service

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[1] DLC Exhibit LAC-2, page 9.

they receive. For example, if Duquesne's distribution rates reflect the uncollectible expense it is projected to incur for both POLR and delivery service, using an assumption that 75% of residential customers will take generation service from POLR, during the period in which the distribution rates will be in place Duquesne would overcharge distribution customers if the number of POLR customers drops to 25%. And the reverse will also be true: if all residential customers returned to POLR while these distribution rates are in place, Duquesne would be exposed to a jump in its uncollectible expense (compared to the amount embedded in its rates) and would have no way of recovering the shortfall, absent filing another rate case in order to adjust its distribution rates on a going forward basis.

Similarly, shopping customers will also be overpaying, since they will be required to pay twice for the same costs. They will pay for energy-related expenses in the energy charges they pay to the EGS and again in the distribution rate they must pay to Duquesne.

The most important reason for accurate cost allocation in this context, however, relates to the serious anticompetitive effect if Duquesne is able to continue to underprice its competitors -- EGSs like Direct Energy -- by being able to price its POLR product to recover only some of the costs that Duquesne incurs in providing the service. It should be obvious that Duquesne's competitors must recover all of the costs of serving customers in the price it charges to its customers. If one competitor has the ability to recover some of those costs in the charges for other products, it gives it a huge potential competitive advantage and significantly increases its ability to retain existing customers and lure back customers who may have shifted to a competitive supplier.

Q. HOW DOES THIS SUBSIDY WORK TO SUPPRESS COMPETITION?

A. It could work in several ways. First, it unduly burdens non-POLR customers with POLR-related costs. For example, if a customer chooses to use a competitive supplier (EGS), it has to pay its share of the competitive supplier's overhead costs, billing costs, credit costs, legal costs, supply costs and the like. It also has to pay those same costs to Duquesne Light in the form of distribution rates. So, if on the first day of a POLR period, the cost of energy was exactly the same for Duquesne and the competitive supplier, Duquesne would have the overall cost advantage, because Duquesne would be recovering its POLR costs through non-POLR related charges. The EGS needs to collect *these costs in its energy charges. Duquesne's cost recovery proposal is inherently anti-*competitive.

If as the market progresses, wholesale prices move lower than the POLR rate, then some suppliers might enter the market to offer savings. In that instance, because of customer migration, Duquesne Light would experience decreased POLR costs, but no decrease in recovery of those costs, because they are collecting all of these costs from the distribution customers. They could then use that excess recovery to invest in and pay for systems in a deregulated affiliate retail supply company like Duquesne Light Energy. Again, on the same day, the cost of energy should be the same for Duquesne Light Energy and a competitive supplier but, in this example, Duquesne Light Energy would have a cost advantage because of the subsidy embedded in the distribution rates used to fund the retail business. Again, Duquesne's cost recovery proposal is inherently anti-competitive. This over-collection of distribution costs effectively gives Duquesne an anti-competitive position in the provision of POLR service and in competitive markets.

Q. ARE THE POLR RATES DUQUESNE LIGHT CHARGES "BELOW MARKET" IF THE COSTS DISCUSSED ABOVE ARE NOT APPLIED APPROPRIATELY TO POLR AND REFLECTED IN ITS POLR RATES?

A. Yes. If these costs are not applied, POLR charges will always be "below market." In addition to the subsidy this creates as discussed above, it also sends the wrong price signals to consumers. Consumers believe the cost of electricity service is lower than it truly is, causing distortions in their decision making, including the decision to select a generation provider.

Q. DOES DUQUESNE HAVE AN INTEREST IN RETAINING OR INCREASING ITS POLR LOAD?

A. Yes it does. Duquesne's reports to shareholders and investment analysts show that its POLR service is quite profitable. In 2005 alone, Duquesne reported that it earned some $28.4 million (unadjusted) on its "POLR/supply" service. This represented some 25% of its total unadjusted earnings for that year of $112.9 million.[2] In recent reports to the financial community, it has made clear that its current goal is not only try to maintain POLR service as a profit center, but to try to "be the supplier of choice for customers" providing a "stable source of energy at a reasonable price,"[3] that is, to try to retain customers and grow the service. By assigning as few costs as possible to its POLR service, and, as a result, recovering all of its costs (other than purchased power costs) in

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[2] Direct Energy Exh. FPL-1 (Duquesne Response to Direct Energy Interrogatories, Set I-10 – March 2006 Financial Community Presentation, p. 29); *see also* DLC Attachment DFR-III-F-1B (Duquesne Holdings 2005 Form 10-K, p. 25).

[3] Direct Energy Exh. FPL-2 (Duquesne Response to Direct Energy Interrogatories, Set I-10 – Jefferies & Company Meeting, Jan 18, 2006, p. 9). The Company has reiterated this sentiment in describing its POLR service as "provid[ing] a viable option for smaller customers who want a basic service from their hometown utility that provides a stable source of energy at a reasonable price, without having to deal with the complexity and uncertainly of future markets." DLC Answer to CNE Interrogatory Set I No. 34.

its distribution rates, Duquesne will be able to continue to underprice its POLR service (in relation to costs) and retain or grow its market share through rates that are anti-competitive.

Q. HAS THE COMMISSION RECOGNIZED THAT ELECTRIC DISTRIBUTION COMPANIES SHOULD BE REVISING THEIR DISTRIBUTION RATES TO REMOVE POLR COSTS IN THE POST-TRANSITION ENVIRONMENT?

A. Yes. In its post-transition period POLR service notice of proposed rulemaking (NOPR), the Commission concluded that "all reasonable, identifiable costs associated with providing default service should be fully allocated to default service rates."[4] The Commission also concluded that "[t]he public interest is served by both the appropriate allocation of costs among customers and recovery of those costs through the correct rates."[5] To accomplish this, the Commission proposed a "Customer Charge" to recover the non-supply costs of providing post-transition POLR service. The non-supply costs and functions identified by the Commission are "billing, meter reading, collections, uncollectible debt, customer service, a return component, taxes, and other reasonable and identifiable costs."[6] The Commission concluded that these costs "may be more appropriately recovered through default service rates than distribution rates," stating that the reallocation of costs distribution and default service rates should be generally revenue neutral with respect to overall rates, that is, "[a]ny increase in default service

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4 *Rulemaking Re Electric Distribution Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant To 66 Pa. C.S. §2807(e)(2)*, Docket No. L-00040169, Order entered December 16, 2004, at 12.

5 *Id.* at 16.

6 *Id.*

rates resulting from reallocation should be matched by a near corresponding drop in distribution rates."[7]

Q. IS DUQUESNE'S DISTRIBUTION RATE COST ALLOCATION CONSISTENT WITH THE COMMISSION'S CONCLUSIONS IN ITS POLR NOPR?

A. No, and as the Commission's POLR NOPR is for utilities coming out of the transition period, Duquesne is actually well behind in following the Commission's conclusions because Duquesne is already out of the transition period.

Q. HAS THIS COST ALLOCATION ISSUE BEEN LITIGATED BEFORE WITH RESPECT TO DUQUESNE?

A. Not exactly. Unbundling billing and metering costs from distribution rates was addressed in Duquesne's restructuring proceeding, but the Commission decided to unbundle rates based on the previous cost of service studies and concluded that further unbundling of billing and metering costs was not appropriate at that time based on that record.[8] Duquesne was still in its transition in its POLR I case. Duquesne filed its POLR II case on June 30, 2000 and requested Commission approval by September 1, 2000. As a result, the stakeholders engaged in a collaborative process over the next few months culminating in the POLR II settlement approved by the Commission in November 2000. While the POLR II settlement rates became effective upon the expiration of competitive transition charges ("CTC") for each rate class, the settlement also capped Duquesne's transmission and distribution rates through 2003. In Duquesne's POLR III case, some EGSs argued that there were POLR-related customer

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[7] *Id.*

[8] *Application of Duquesne Light Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code*, Docket No. R-00974104, Order entered May 21, 1998, at 256, 261.

care costs and administrative expenses embedded in Duquesne's distribution rates, and proposed the recovery of these costs through retail adders in lieu of an unbundling proceeding. The Commission approved a small retail cost adder and a retail risk adder for Duquesne's large commercial and industrial customers, and concluded that the issue of distribution rate subsidies was better addressed in other proceedings because the POLR III record did not support a finding that substantial POLR costs were embedded in Duquesne's distribution rates.[9] I conclude that this issue is ripe for resolution.

IV DUQUESNE IS OVER-STATING IT DISTRIBUTION REVENUE REQUIREMENTS

Q. DO YOU BELIEVE THAT DUQUESNE LIGHT IS ACCURATELY REFLECTING ITS TRUE COST OF PROVIDING DISTRIBUTION SERVICES IN ITS CURRENT RATE CASE?

A. No. Duquesne Light is materially misrepresenting its true distribution cost of service.

Q. IN WHAT MANNER ARE THEY MISREPRESENTING THEIR COSTS?

A. They are overstating their true cost of distribution service by failing to allocate or assign any of their POLR- or generation-related costs (other than purchased power and revenue-related taxes) to POLR service.[10]

Q. WHAT COSTS DO YOU BELIEVE ARE EMBEDDED IN THEIR DISTRIBUTION COST BUILD-UP THAT SHOULD BE EXCLUDED FROM THESE RATES.

A. Based on the information we have received from the Company, it is not possible to detail all of the costs, nor is it possible to give a precise estimate of the total dollars involved.

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9 *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service*, Docket No. P-00032071, Order entered August 23, 2004, at 19, 44.

10 Direct Energy Exh. FPL-3 (Duquesne Answer to Direct Energy Interrogatory, Set I, No. 13).

However, Duquesne has confirmed that it has not removed from its calculation of its revenue requirement any expenses associated with the provision of POLR service other than purchased power and revenue-based taxes associated with that power. Specifically, Duquesne has not made any adjustment for uncollectible expense, cash working capital requirements, customer accounting, administrative/general ("A&G") expenses or sales expenses associated with those purchased power costs. [11] As a result if Duquesne's approach is adopted, the Company will recover 100% of its POLR-related expenses, other than purchased power and revenue-based taxes through non-bypassable distribution charges.

Q. WHAT IS THE MAGNITUDE OF THESE COSTS?

A. Again, it is not possible to say with certainty what the magnitude is. However, with some very logical and rational assumptions, the number is well into the tens of millions of dollars. Duquesne Light has confirmed that adjusting the cash working capital requirements for POLR costs would reduce the cash working capital requirement by \$18.6 million.[12] Reducing Duquesne's Rate Base by that amount would reduce its revenue requirement by \$1.7 million. Additionally, the total unadjusted uncollectible accounts expense and CAP cost recovery being charged in distribution rates for residential customers alone is \$27.9 million. [13] At least \$16.1 million of this should be

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11 Direct Energy Exh. FPL - 4 (Duquesne Answer to Direct Energy Interrogatory Set I, No. 12).

12 Direct Energy Exh. FPL - 5 (Duquesne Answer to Direct Energy Interrogatory Set I, No. 18).

13 DLC Exh. HSG-1A, p. 7. This consists of uncollectible accounts expense for the Residential rate classes and the total CAP subsidy of \$20.3 million sought to be recovered in distribution rates.

allocated to POLR expenses. In total, a portion of over $100 million should be allocated to POLR operations.

Q. HOW DID YOU ARRIVE AT $16.1 MILLION FOR UNCOLLECTIBLE EXPENSE AND CAP COSTS TO BE ALLOCATED TO POLR?

A. It is an estimate based on Duquesne's current residential service "RS" tariff. Duquesne's RS rate class has a bill cost build up that includes a customer charge and separate charges for transmission, distribution and generation. The total per kwh charge that a RS customer sees today is 9.6248 cents per kWh. 6.3031 cents per kWh is for energy and energy-related services. These customers are also billed $6.48 monthly for what Duquesne calls a Customer Distribution Charge. As a result of the fixed monthly portion of the bill, customers who use fewer kWh per month pay a larger portion of their monthly bill to cover distribution costs. I have calculated that a customer who uses 500 kWh per month would be billed $54.60. Approximately 42% of that amount would be for transmission and distribution costs. If only 42% of the uncollectible and CAP expenses allocated to the Residential rate class were allocated to transmission and distribution rates, and the other 58% was allocated to POLR service, we would see a reduction in the revenue requirements of at least $16.1 million. Tax requirements on those revenues would also be moved to POLR.

Q. IS 58% THE RIGHT ALLOCATION FACTOR TO APPLY TO UNCOLLECTIBLE AND CAP EXPENSE?

A. Without a complete cost of service study, (which I am recommending be conducted before any adjustment is made), the exact number is impossible to predict. This percentage was based on the percentage of POLR charges for an RS customer who uses only 500 kWh per month under the current transmission, distribution and POLR rates. At today's rates, approximately 61% of a 1000 kwh per month customer would be for POLR charges. The percentage of POLR charges increases as kWh usage increases. The distribution rate increase requested in this proceeding will likely change the percentage results, as will increases or decreases in future POLR rates. This is exactly the reason a complete cost of service study must be performed by Duquesne.

Additionally, when Duquesne is not paid, they are not paid for POLR service as well as transmission and distribution services. Duquesne does not have the right to allocate all of its uncollectible costs to its T&D customers. Interestingly, according to Duquesne's tariff, if a customer makes a partial payment, then that payment is first applied to the wires charges and then to the energy charges. If they followed that same payment allocation pattern in this case, the allocation of uncollectible expense should bias toward a higher POLR allocation than would be produced if uncollectibles were allocated merely on the basis of the share of total revenues which are produced by POLR charges.

Q. WHY DO YOU INCLUDE THE CUSTOMER DISTRIBUTION CHARGE IN YOUR ESTIMATE OF THE T&D PORTION OF THE TYPICAL CUSTOMER'S BILL ABOVE?

A. I use it in my calculation because Duquesne Light calls it a "Distribution Charge." I have no reason to believe that all of the costs embedded in that charge are actually distribution-related and not POLR-related costs.

Q. IS IT YOUR CONTENTION THAT DUQUESNE HAS INCLUDED COSTS IN ITS DISTRIBUTION REVENUE REQUIREMENT THAT WOULD NOT BE INCURRED IF IT WERE NOT PROVIDING POLR SERVICE?

A. Absolutely. A good example is the uncollectible expense I just discussed. Duquesne's *pro forma* claim for uncollectibles is calculated on the basis of historical experience, which is then converted into a "percent of revenues" basis, clearly showing that the Company believes that the level of this expense directly correlates to the level of revenues it bills. It is also obvious that if Duquesne no longer provided POLR service, and only provided the distribution portion of the service, its retail revenues would drop by several hundred million dollars, and, in turn, its uncollectibles would also drop by the same relative degree.[14] Other examples of items directly affected by Duquesne's level of revenues include cash working capital and regulatory assessments (based upon gross intrastate operating revenues.)

Q. WHAT ARE OTHER COSTS THAT YOU BELIEVE ARE LIKELY BEING MISAPPLIED TO DISTRIBUTION?

A. In its Distribution Revenue Requirement, Duquesne seeks recovery for supervision, meter reading expenses, customer records and collection expenses, and CAP costs. These costs are not related to revenues on a one-to-one basis but clearly would be reduced if Duquesne only provided distribution services. They also seek recovery for A&G expenses including data communications, "Other" (presumably including the President's salary or the cost of his "desk"), office supplies and expenses, credit and legal services, other outside services, employee pensions and benefits, and various insurance coverages, regulatory expense, advertising expense and a miscellaneous general expense. While the exact relationship between these costs and the Company's POLR service is not as clear, well accepted cost allocation principles of which I am familiar would allocate some portion of these "joint and common costs" to the POLR service line of business. I note that Duquesne itself allocated a small share of administrative and general expenses to its

14 Similarly, the Company's CAP subsidy is directly related to the total amount of revenues that the Company charges to low income customers. If the Company only provided distribution service, and provided a CAP subsidy only on its portion of the bill, its CAP subsidy, that it seeks to recover from remaining customers, would be proportionally smaller.

transmission line of business in its "jurisdictional cost study." I can envision no reason why POLR service should be treated any differently from the standpoint of cost allocation.

Q. WHAT PORTION OF THESE EXPENSES SHOULD NOT BE RECOVERABLE IN TRANSMISSION AND DISTRIBUTION RATES?

A. I cannot say precisely what percentage of these costs should not be allocated to transmission and distribution. However, Duquesne has made no attempt to remove any POLR related costs from this rate proceeding. This is anti-competitive, and it unduly burdens customers who are not taking POLR service with POLR-related costs and is clearly wrong. I am also advised that it is not consistent with Pennsylvania law, which requires that a POLR provider "shall acquire electric energy at prevailing market prices to serve that [POLR] customer and shall recover fully all reasonable costs."[15] Accordingly, the Company should have conducted a study to separate all of its costs between the distribution function and the POLR or generation supply function, just as it did for transmission service. As I explain in more detail below, the Commission now must order the Company to conduct such a study which assigns costs to POLR service using appropriate cost causation principles.

Q. WHAT IS THE BASIS ON WHICH YOU WOULD ALLOCATE COSTS?

A. Several allocation methodologies are available, and each cost center should be evaluated to determine the most appropriate allocator. The guiding principles should be that costs should be allocated to POLR if: 1) the cost or expense would completely go away if Duquesne was no longer the POLR provider; 2) the cost or expense would be reduced in direct proportion to the reduction in POLR revenues; 3) the cost or expense would be

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15 66 Pa. C.S. § 2807(e)(3).

reduced in some way -- but not necessarily in direct proportion to the revenue reduction -- if the Company did not provide POLR service (in which case an appropriate allocator should be determined); and 4) the cost is a joint and common cost, which is related to all services provided by the Company (in which case, the cost would be allocated on the same relative basis as all prior costs). For example, if Duquesne stopped providing POLR service, the number of customer service representatives that Duquesne would need to employ in the customer call center and reflect in its distribution rates could be reduced by some amount. In my experience, the majority of the billing and collection calls are related to the size of the bill, which, in turn, is related to the energy portion of the total charge . An appropriate cost allocation can be used to reflect such a cost relationship. One basis for determining this percentage would be to do a study of the number and portion of customer service calls which relate wholly or substantially to the POLR charge on the customer's bill. If Duquesne only provided delivery service and could redirect such calls to the (separate) POLR service provider, the number of FTE's in the customer call center could be reduced. Absent the time to conduct such a study, an appropriate allocator, such as revenues or earnings could be used.

Most obviously, costs that are related to revenues should be allocated on a revenue basis. This would include, among other costs, the cash working capital and uncollectible and CAP expenses discussed above. It would also include expenses like customer collections expense and billing expense. Regulatory expenses are estimated by Duquesne based on gross intrastate operating revenues yet DLC has allocated 100% of the Pennsylvania jurisdictional portion of this expense ($6.1 million) to be recovered in the distribution revenue requirement. Revenue should be used as an allocator for some joint and common costs, like executive salaries.

Personnel count should be another allocator. For example, how many FTEs are performing POLR-related services? Several people are required to execute a 24 hour a day, seven day per week energy center. Those costs are 100% related to the provision of POLR service, yet none of the costs have been allocated to POLR by the Company. Also people are required to negotiate the contracts, review the credit of the counter-parties, review the contracts, acquire working capital and credit facilities to facilitate power delivery, review those facilities, develop IT systems to track power flow, and generally execute all of the functions required to deliver power to the POLR customers. FTE count could be used to allocate salaries, benefits, pensions, payroll taxes and perhaps others.

Square footage in the building should be used to allocate building leases, mortgages, rents, etc.

Some costs, like advertising, might be totally allocated to POLR, because there is really no need to advertise the monopoly regulated wires service at issue in this proceeding.

IV. IMPACT OF OVER-COLLECTION

Q. DO YOU BELIEVE THAT THESE COSTS SHOULD BE DISALLOWED FOR RECOVERY BY THE COMMISSION?

A. Duquesne should be allowed an opportunity to recover these costs. However, they should be recovered from the appropriate portion of the rates charged to customers. POLR-related costs should be recovered only from POLR customers. Transmission and distribution costs should be recovered from all transmission and distribution customers.

Q. ARE THE COSTS THAT YOU ARE CONCERNED WITH MATERIAL IN NATURE?

A. Yes. $166 million, more than one-third of the entire revenue requirement request, is for operating expenses. There are also tax gross ups on this amount, so the impact is compounded. As outlined above, a significant portion of the operating expenses could be removed from the distribution revenue requirement and assigned to POLR for recovery. One could also analyze the Company's claimed cost of equity and assign a portion cost of equity requirement to POLR.

Q. HOW WOULD YOU PROPOSE THAT DUQUESNE SOLVE THE PROBLEMS ASSOCIATED WITH THIS MISALLOCATION OF COSTS?

A. This Commission must order Duquesne to conduct a POLR Cost Allocation Study which removes from the distribution revenue requirement costs which are directly or indirectly associated with the provision of generation service (POLR). It must also remove from its distribution costs a share of its overhead and A&G expenses. As noted, the first basis on which such costs should be identified is "would the cost be incurred at all, or 2) would it be incurred at the test year levels if Duquesne did not provide POLR service at all? (An "avoided cost" standard.) After those costs are identified, a share of "joint and common costs," such as overhead and A&G expenses, should be assigned to POLR.

Duquesne should file the study shortly after its distribution rate increase request is determined by the PUC. With this as a first step, we would have a solid understanding of the total costs that Duquesne Light is entitled to recover. A workshop process should be utilized in which interested parties should meet with Duquesne (along with PUC staff) in order to attempt to resolve issues raised by the proposed generation cost study. If the issues can't be resolved via workshop, a hearing process should be initiated, with the goal of identifying costs that should not be recovered in the Company's distribution rates.

Q. IF DUQUESNE WERE FORCED TO CONDUCT THIS STUDY, AND IT FOUND SEVERAL MILLION IN COSTS TO BE ALLOCATED TO POLR, HOW SHOULD DUQUESNE COLLECT THESE COSTS?

A. From a policy and legal standpoint, two things are clear: Duquesne may NOT recover in its distribution rates costs that are associated with providing POLR service. Second Duquesne is obligated to recover in its POLR rates "all reasonable costs" of providing POLR service. Direct Energy has no objection if Duquesne is permitted to file a revision to its present POLR rates to recover any revenue requirement removed from the distribution revenue requirement such that the rate revisions would be revenue neutral to Duquesne. If there is some impediment to such immediate recovery, these additional costs can be included in Duquesne's POLR IV proposal, for implementation in January 2008. But, in no event can Duquesne be permitted to continue to charge distribution rates which recover POLR related costs.

Q. SHOULD DUQUESNE'S DISTRIBUTION RATES BE REDUCED TO ELIMINATE POLR-RELATED COSTS EVEN IF THE COMMISSION, FOR SOME REASON, ELECTS NOT TO ADJUST DUQUESNE'S POLR RATES AT THE SAME TIME?

A. An argument can be made that the Company's distribution rates must be adjusted as soon as the Commission comes to a conclusion on the degree to which they are overstated due to the inclusion of POLR-related costs. Duquesne, after all, had the obligation in the first instance to propose a distribution revenue requirement that only included distribution related costs. However, such an action could have an adverse financial effect on Duquesne which could have negative consequences for customers and competitors – as well as the Company – in the long run. Accordingly, I recommend that the Commission simultaneously adjust Duquesne's distribution rates and its POLR rates so that the process is revenue neutral to Duquesne, consistent with the Commission's directive in the POLR NOPR.

Q. IF THE COMMISSION DEFERS REVISING DUQUESNE'S POLR RATES UNTIL POLR IV, WHAT OTHER STEPS SHOULD IT TAKE?

A. If the Commission finds that Duquesne is over-collecting its distribution rates, a deferral is not acceptable. This Commission should give Duquesne the option to do one of two things. The first would be to completely eliminate the misallocation of costs. I have described above how to do this. The second alternative would be to implement policies consistent with the concept of continued development of the competitive markets. These *have proven to be successful in* New York *at helping overcome this cross-subsidy issue.*

First, if an EGS's customer opts for utility consolidated billing, Duquesne should be ordered to send the bills and utilize the same collection procedures they utilize for their own affiliates and the POLR providers to collect EGS's bills. In the event of non-payment by an EGS's customer, Duquesne would have the right to terminate the defaulting customer's service as it does today for itself. Second, Duquesne should apply the uncollectible expense it recovers from suppliers' customers to itself and pay the suppliers in full for the generation services they provide. As stated in the Company's 2005 10-K, this is no different than the billing risks it takes on today and seeking recovery for, nor is it any different than the billing services offered today to its wholesale suppliers, including its own affiliate Duquesne Power.

Third, Duquesne should create an "EGS" referral process where customers who call in to Duquesne's service center with any complaints or billing questions about his or her POLR rates are given information about a participating EGS who will guarantee savings to that customer for a period of at least two months if the customer chooses to switch from POLR.

As stated above, these steps generally have proven to be successful in enabling competition in some of the New York markets including the O&R service territory, even when POLR and distribution rates have not been appropriately aligned.

Q. WHAT OTHER IMPROVEMENTS COULD DUQUESNE LIGHT MAKE TO THIS RATE FILING?

A. As part of the process of reallocating costs and resetting the Company's rates, Duquesne Light should study the costs and benefits of developing and implementing an advanced metering infrastructure in its service territory. Advanced metering will give customers greater tools to control energy costs, engage in conservation and track real time market prices for energy. Their availability will also enhance the ability of EGSs to offer creative products and services to customers, thereby enhancing competitive opportunities and options, so that by 2011, when the entire state will have completed their restructuring transition plans, Duquesne customers will have access to full and complete information and customer choice

Q. WHAT IS THE TIMELINE YOU WOULD RECOMMEND FOR THESE SYSTEM IMPROVEMENTS?

A. Duquesne should move all customers above 300 kw (those currently on hourly pricing) to advanced meters by the end of 2007. It should also migrate one-third of the remaining customers (Residential and C&I) to advanced metering infrastructure in each of the years 2008, 2009 and 2010.

Q. HOW SHOULD THIS INFRASTRUCTURE BE PAID FOR?

A. Duquesne is in the midst of significant systems upgrades and is seeking a significant distribution rate increase. Duquesne should incorporate these changes into its plan and implement these changes in concert with other system upgrades planned. Some of these investments may offset the need for some of the current planned distribution investments. The incremental investments should be rate-based. Any resulting change in revenue requirements due to these investments should be passed through to the distribution customers in the same manner that all distribution investments are paid for. However, any order directing the installation of advanced metering should be preceded by analysis, authorized or conducted by the PUC to identify the real benefits and to assure that the costs are justified.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. It does.

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EMPLOYMENT

President, Starlight Energy / Retail Energy Services Consulting July 2004-Present
Pittsburgh, PA

- Morphed startup entity seeking $20 million in equity capital to Consulting Firm focused on Energy Market Development issues.
- Providing market development strategy planning and guidance to large national retail market participant. Assisting in development of competitive retail markets in mid-Atlantic region (PJM).
- Drafted business plan and developed pro forma financial projections for national retail electricity delivery business.
- Secured $100 million credit relationship and working capital financing from market participants to enable launch of retail electricity company.
- Worked with counsel to develop legal analysis and strategies re: non-solicitation agreements.
- Designed risk management protocols to educate potential investors.
- Developed industry and venture contacts to secure funding for start up of business.
- Developed application and received FERC market-based rate authority.
- Board Member -- Center for Advancement of Energy Markets.

Director, Regulatory Affairs, Strategic Energy November 2001-June 2004
Pittsburgh, PA

- Managed regulatory group of 15 people working in 12 different states and the District of Columbia.
- Corporate responsibility for managing regulatory strategy, regulatory risk and achieving desired regulatory results. Advocated for market design structures in emerging electricity markets. Assisted employees in regional regulatory strategy development and execution.
- Assisted sales group with complex sales and was instrumental in educating key customers on complex regulatory framework, assisting in closing approximately $60 million in annual incremental sales.
- Led company's Standard Market Design ("SMD") efforts at FERC and was the Company's lead FERC representative. Educated FERC staff and Commissioners about unique risks to retail community in SMD efforts.
- Managed $4 million annual budget and managed group to earn returns on regulatory investment in excess of 1,500%.
- Managed and expanded regulatory group in Post-Enron market environment to become the recognized national leader in retail regulatory policy development and expertise.
- Qualified as policy expert to testify on behalf of company and others in regulatory proceedings across the nation.
- *Served on ERCOT Board of Directors as REP sector representative.*
- Served on Board of Directors of Electric Power Supply Association (EPSA).

Served on Board of Directors of Mid-Atlantic Power Supply Association (MAPSA), now called Retail Electric Supply Association (RESA).

Senior Manager October 1998-October 2001
Arthur Andersen
Washington, DC

- Responsibility for developing Andersen's transmission restructuring business in Eastern half of US market.
- Achieved annual consulting sales in transmission restructuring practice in excess of $1 million.
- Managed overall development of the American Transmission Company business structure. Andersen project team included members from audit, consulting, IT and tax functional areas.
- Project manager for Alliance RTO development project that resulted in the first Transco filing at FERC. Developed pre-filing strategies and materials to educate FERC staff on Transco issues.
- Managed the review and analysis of FERC NOPR on RTO development for a large Southeastern Utility. Analysis included recommendations for regulatory response, financial options for developing RTO, and analysis of the impact of moving to RTO model.
- Managed the development of corporate-wide analysis of operational impacts of moving to RTO structure for a southeastern utility. Analysis included process redesign within a currently integrated utility operating in the future without transmission asset control. Overall regulatory strategy was developed and tradeoffs between FERC incentives on transmission restructuring and local ratemaking allowances were analyzed. The overall financial and regulatory impact of moving transmission out of integrated business unit was presented to company board of directors.
- Managed the facilitation process of 6 northeastern utility management teams attempting to develop sound business model for restructured transmission grid operations. Facilitation effort included development of financial model of ISO NE transmission tariff, development of agreeable terms to put into partnership documents and development of transmission planning processes.

Associate Consultant January 1995-September 1998
Putnam, Hayes and Bartlett, Inc.
Washington, DC

- Associate consultant in firm's generation restructuring practice.
- Developed pro forma financial statements to value several generation plant transactions.
- Generated carve-out analyses valuing SO_2 allowances, NOx credits and other possible environmental assets to evaluate sensitivities on environmental policy risks.
- Developed SO_2 emission management strategy tool for large mid-atlantic utility. Analysis included evaluating options including construction of scrubbing technology on large coal fired plant, purchasing SO_2 allowances for fleet, and selling certain generation assets.
- Prepared direct and rebuttal testimony for expert witnesses in several different matters in front of FERC, State Commissions and other tribunals. Assisted in the preparation of witnesses for hearings.
- Participated in the evaluation of estimating cost of environmental remediation at several different RCRA and CERCLA sites around the country.

EDUCATION

MBA with concentrations in finance, entrepreneurship and environmental management
Class of 1993

Tepper School of Business, Carnegie Mellon University, Pittsburgh, PA
(supplemental coursework taken at Heinz School of Public Policy and Engineering Department)

B.S. in Transportation and Logistics
Class of 1988
University of Maryland, College Park, MD

TESTIMONY, SPEECHES AND PAPERS

Prepared Direct Testimony of Frank Lacey On Behalf of Strategic Energy, LLC, before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 6, 2002.

Prepared Rebuttal Testimony of Frank Lacey On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 20, 2002

Cross Examination testimony of On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. July 2002.

Prepared Testimony of Frank Lacey on the subject of truing up the CERS Fee On Behalf of Strategic Energy, LLC before the Public Utilities Commission Of the State Of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. March 19, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v.Duquesne Light Company*, Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. January 2003.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy L.L. C. Before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. February 2003.

Prepared Supplemental Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. November 2003

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. July 1, 2003.

Prepared Direct Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No.

02-2879-EL-AAM. May 19, 2003.

Prepared Supplemental Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the _Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company_ Case No. 02-2779-EL-ATA and the _Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code_ Case No. 02-2879-EL-AAM. June 12, 2003.

Deposition Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the _Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company_ Case No. 02-2779-EL-ATA and the _Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code_ Case No. 02-2879-EL-AAM. May 2003 and June 2003.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the _Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company_ Case No. 02-2779-EL-ATA and the _Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code_ Case No. 02-2879-EL-AAM. June 2003.

Oral Testimony of Frank Lacey before the Standing Committee on Energy of the New York State Assembly on the issue of Ensuring a Reliable Supply of Electricity to the People of New York, Chairman Paul D Tonko, presiding. March 6, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the _Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service._ Docket No. P-00032071. February 2004.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the _Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service._ Docket No. P-00032071. February 2004.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the _Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service._ Docket No. P-00032071. April 1, 2004.

Oral Testimony of Frank Lacey at the _POLR Roundtable_ before the Pennsylvania Public Utility Commission re: Optimal Future POLR Design models. May 3, 2004.

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of _The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period_, Case No. 03-93-EL-ATA, _The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO_, Case No. 03-2079-EL-AAM, and _The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development_

Period, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 6, 2003.

Deposition of Frank Lacey in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 2003.

Cross Examination Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 18, 2003.

Oral Testimony of Frank Lacey before the Michigan Senate Committee on Technology and Energy on the subject of revision to Public Act 141, the Michigan Electricity Choice and Restructuring Act, Chairman Bruce Patterson, Presiding. May 19, 2004.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bill 561 on the subject of communications between electric companies and suppliers to enhance the development of competitive electric markets, Chairman Thomas Middleton, Presiding. March 7, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bills 814, 1048, 1051 and 1078 on the subject of retail electricity market design, Chairman Thomas Middleton, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland House of Delegates Economic Matters Committee on House Bills 1334, 1654 and 1712 on the subject of retail electricity market design, Chairman Dereck Davis, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of *Petition of Direct Energy Services, LLC for Emergency Order*, Docket No. P-00062205, April 11, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association (RESA) before the Maryland Special Joint Legislative Session on Senate Bill 1 on the subject electricity market issues, Chairman Thomas Middleton and Chairman Dereck Davis co-presiding. June 13, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of _Policies to Mitigate Potential Electricity Price Increases_, Docket No. M-00061957, June 22, 2006.

Lacey, Frank and Taff Tschamler, *Implementing Principles of Default Service: A Roadmap for Competitive Retail Power Markets*. Paper released at PA POLR Roundtable, May 2004.

Building a for-profit Transmission Operation; Key Business Parameters. Presentation to the EEI Transmission Planning Task Force, Kansas City, MO.

Several industry and client-specific presentations.

Duquesne Light Company
Docket No. R-00061346

DES-I-10
William F. Fields

Direct Energy Services, LLC (DES)
Interrogatories Set I

10. Please provide copies of any and all presentations (including transcripts of any conference calls or other oral presentations) by Duquesne Light and/or Duquesne Light Holdings to investors, investment analysts, employees, or customers regarding Duquesne's (or Duquesne Light Holdings) business and financial results or future business plans or projections

Response:

See attached investor presentations.

Duquesne Light

"Executing On The Basics"

Financial Community Presentation

March 2006

Company Representatives

Mark Kaplan	Senior VP and Chief Financial Officer
Darrin Duda	Manager, Investor Relations and Trust Investments

2005 Earnings Review

($ in Millions, except per share information)

	Actual 2005	Adjusted 2005
Duquesne Light – T&D	$36.5	$36.5
POLR / Supply	28.4	19.0
DQE Financial	30.2	28.2
Duquesne Energy Solutions	35.9	23.2
DQE Communications	2.5	2.5
All Other	(20.6)	(23.0)
Total	**$112.9**	**$86.4**
Earnings per Share	$1.45	$1.11

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2006 Earnings Guidance - - Key Assumptions

- No rate case impact in 2006
- Power plant acquisition closes in June 2006
- Excludes fair value accounting for derivative energy contracts
- Section 29 related earnings:
  - Synfuel facilities operate full year
  - Tax credit phase out minimal

Note: Earnings guidance information is as of February 14, 2006. The company is not reaffirming and has not reaffirmed since that date.

30

Duquesne Light Company
Docket No. R-00061346

DES-I-10
William F. Fields

Direct Energy Services, LLC (DES)
Interrogatories Set 1

10. Please provide copies of any and all presentations (including transcripts of any conference calls or other oral presentations) by Duquesne Light and/or Duquesne Light Holdings to investors, investment analysts, employees, or customers regarding Duquesne's (or Duquesne Light Holdings) business and financial results or future business plans or projections

Response:

See attached investor presentations.

Duquesne Light

The information contained in this presentation is historical in nature and is for research purposes only. Duquesne Light Holdings, Inc. is not reaffirming any earnings guidance, financial projections or other forward-looking statements contained in this presentation. Providing this material does not constitute in any way a reaffirmation of such guidance, projections or other forward-looking statements.

Duquesne Light®

Jefferies & Company Meeting
January 18, 2006

Building on the Basics Strategy

Major Initiatives

- Be the supplier of choice for customers
  - Stable source of energy at a reasonable price
- Make necessary T&D infrastructure investments
  - Continue providing secure, reliable customer-focused services
- Help to solve nationwide environmental challenge through use of renewable energy
  - Use of reliable and renewable landfill gas

Duquesne Light

POLR Plan

Small Customers

- Provide fixed-price default generation service to POLR customers through 2007
  - 74% customer retention through September 30, 2005
- Signed contracts with multiple investment-grade suppliers
  - Substantially hedged supply position for '05-'07 combined expected load obligation
- Represents opportunity to earn margin for long term

Duquesne Light

Direct Energy Services, LLC
Interrogatories Set I

13. Please detail what portion of Duquesne's total expense or amount for each of the categories in No. 12 above are being recovered in Duquesne's POLR rates, and the portion or amount (or percentage of total *pro forma* expenses) being so recovered.

RESPONSE:

Duquesne's total expense recovered in Duquesne's POLR rates are the cost of energy and the related revenue taxes.
Also, please refer to DE-I-12.

Direct Energy Services, LLC
Interrogatories Set I

12. Specifically, indicate the portion (if any) of the following items which has been removed from *pro forma* expenses or rate base in order to assign cost recovery to POLR service.

(a) Uncollectible expense;

(b) *Cash Working Capital;*

(c) Customer Accounting Expense (other than uncollectibles);

(d) Administrative and General expense;

(e) Sales expense.

RESPONSE:

(a) None

(b) None

(c) None

(d) None

(e) None

By way of further answer, this treatment of the referenced expenses is consistent with the fact that the Company, as an electric distribution company, is the provider of last resort for energy supply, and also is consistent with the manner in which the Company's POLR rates were established by the Commission in the Company's POLR III proceeding.

Direct Energy Services, LLC
Interrogatories Set I

18. IF Duquesne did not exclude the such payments and disbursements, calculate the portion of the $51.7 million cash working capital claim (page 21, lines 1-3) that are associated with payments and receipts associated with POLR service.

RESPONSE:

The Company does not have the portion of the revenue lag days associated with the POLR receivables only readily available and therefore cannot provide an exact amount of the cash working capital associated with the purchased power cost and the related revenue.

The lag days associated with the purchased power expenses are $12,548,025, shown on line 5, column 4 of DLC Exhibit 2, Schedule C-4, page 2 of 16.

If the purchased power costs alone were removed from the cash working capital without making a related adjustment for the revenue lag adjustment, the impact on the cash working capital would be a reduction of $18.6 million.

St. No. 1R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

REBUTTAL TESTIMONY OF
FRANK P. LACEY

On Behalf of Direct Energy Services, LLC

Duquesne Light Company Base Rate Case
Docket No. R-00061346

August 2, 2006

RECEIVED

SEP 2 8 2006

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Frank Lacey. My business address is 263 Tresser Boulevard, 8th Floor, Stamford, CT 06901.

Q. ARE YOU THE SAME FRANK LACEY WHO SUBMITTED DIRECT TESTIMONY ON BEHALF OF DIRECT ENERGY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE SUBJECT OF YOUR REBUTTAL TESTIMONY?

A. I wish to respond to the Directed Questions presented by Pennsylvania Public Utility Vice-Chairman James Cawley. I will provide answers from the standpoint of an electric generation supplier which is competing with the EDC, in this case Duquesne.

Q. DO FIXED CHARGES FOR RESIDENTIAL AND SMALL OR MEDIUM COMMERCIAL CUSTOMER DISTRIBUTION SERVICES DISCOURAGE CONSERVATION OF ENERGY?

A. A flat fixed commodity-type charge, or a "cents per kWh" charge, for distribution services will neither encourage nor discourage conservation. It lends itself to using distribution services as if they were a readily available commodity. There will be some desire to not over-use with this pricing approach, because usage comes at a cost. Under this approach, only the quantity that is needed will be consumed.

- A flat fixed monthly charge on the other hand, or a "dollars per month" charge would definitely send the wrong signal with respect to conservation. The analogy here is to sending a child into a candy store with a dollar and saying she can get whatever she wants for that dollar, but that whatever she buys she will have to part with the dollar. It's likely that the child is going to buy all the candy she can for that dollar.

- As in any commodity, the best way to encourage conservation in distribution is *through scarcity pricing*. As *demand increases, if supply is constant* (like distribution would be), then the price should increase to encourage conservation. The scarcity pricing model is probably not best applied to distribution however, unless it is applied to energy as well. If the energy component is priced flat, or in a declining block price, the incentives are completely wrong. If the energy price is flat or declining, then, as demand increases, there will be little or no incentive from either the customer or the utility to curtail use. In fact, the incentive on the part of the utility in this model is to encourage excess usage.
- Unless the energy portion is priced in an appropriate manner, it would be counter-productive to apply scarcity pricing to distribution rates. Despite that, a fixed cents per kWh fee is a more efficient way to allocate distribution than is a large flat monthly fee.

Q. IF SO, WHAT OTHER REVENUE DECOUPLING MODELS CAN BE IMPLEMENTED THAT WOULD OPTIMALLY MEET THE DUAL NEEDS OF PROVIDING INCENTIVES FOR CONSUMERS TO CONSERVE ENERGY, WHILE PROVIDING REASONABLY STABLE REVENUES FOR UTILITIES?

A. Utilities have traditionally had the perverse incentive to have customers "over-use" their assets. With the growth in electricity-based products like computers, advanced television technology, electronic games and gadgets, consumers use more electricity than they have in the past, essentially "over-using" the system from a rate base perspective. One way to have a distribution utility align incentives properly would be to completely decouple its distribution component from the energy component of its bill.

- Decoupling of distribution and energy rates within a utility could accomplish many public policy objectives. First, in a properly structured decoupling mechanism, a utility can be compensated on a virtually risk-less basis for its infrastructure (monopoly) assets. If structured appropriately, the distribution entity would have no incentives to emphasize throughput and also could be fully compensated in times of fair or foul weather, efficiency improvements, peak load shaving, load shrinkage or growth, or other changes in the market dynamics.

- Next, conservation and demand response are much more feasible and likely to be implemented in a decoupled pricing model. The reason is based totally on aligning incentives. If the monopoly assets are compensated in a fair manner, then the asset owner has no incentive to modify behavior to improve the "bottom line" with enhanced throughput. The company could be compensated for its investments in advanced metering and additionally, in times of load shedding, or curtailments, would be made whole.
- Next, decoupling could lead to enhanced competitive markets. For example, if the utility has no ability to capitalize on throughput, it might be less interested in maintaining its stronghold on the customers. A "performance-based" rate structure could also be applied to a decoupled company where a distribution return could be enhanced if certain customer migration threshold levels were achieved.
- The distribution (monopoly) utility should always be allowed to earn a return that is commensurate with the risk associated with the distribution business. Under-earning will ultimately result in under-investment and perhaps other problems that would ultimately lead to higher rates and potential reliability issues. Similarly, allowing the utility to earn excess returns on investment results in over-

investment and perverse operating incentives. A monthly-variable decoupled distribution rate is one solution that will effectively guarantee the fair return over long periods of time.

- A decoupled distribution rate that was set monthly could resolve many of the incentive problems inherent in the traditional utility model. Under this type of mechanism, the base rate could be set based on test-year assumptions applied in this current rate proceeding, or a similar proceeding for other utilities. That rate could then be adjusted for all of the factors mentioned above, and others.

Q. DO DECLINING BLOCK RATE DESIGNS REMOVE THE INCENTIVE FOR CONSUMERS, ESPECIALLY RA AND RH RESIDENTIAL CONSUMERS AND SMALL TO MEDIUM SIZED COMMERCIAL AND INDUSTRIAL CUSTOMERS ("C&I"), TO CONSERVE ENERGY? IF SO, SHOULD DECLINING BLOCK RATES FOR SUPPLY AND DISTRIBUTION SERVICES BE PHASED OUT OVER TIME?

A. The simple answer is yes, declining block rates remove the incentives for consumers to conserve energy. The more difficult question is what has more impact, the energy rate or the distribution rate? It is important to have both of these rates at least, not in conflict with one another.

Q. DO DEMAND BASED CHARGES, AND IN PARTICULAR DEMAND BASED CHARGES FOR DEFAULT SUPPLY SERVICE, REMOVE THE INCENTIVE FOR CONSUMERS, ESPECIALLY SMALL TO MEDIUM SIZED C&I CUSTOMERS, TO CONSERVE ENERGY? IF SO, SHOULD DEMAND BASED RATES FOR SUCH CUSTOMERS BE PHASED OUT OVER TIME?

A. Demand charges in energy rate making are a residual effect of historic rate-making practices. They really have no place in a deregulated environment. Customers are no longer paying to develop the "slice of the system" that they use. As ample evidence of this, one can look to the competitive supply market. I am not familiar with all of the products that all suppliers sell. However, I have been working in the competitive retail market for several years and I have had ample access to competitive product offerings. I do not know of any competitive supplier that charges a demand charge. Similarly, I have never heard of a wholesale supplier selling energy to a retail supplier that uses a demand-based product. With ratepayers out of the risk-sharing of electricity, demand charges are irrelevant.

Q. CAN AND SHOULD RATE DESIGNS VARY AMONG CUSTOMER CLASSES? FOR EXAMPLE, LARGER C&I CUSTOMERS GENERALLY HAVE A MUCH SMALLER PERCENTAGE OF THEIR REVENUES ATTRIBUTABLE TO DISTRIBUTION SERVICES. GIVEN THIS DYNAMIC, DOES THE COMMODITY DESIGN OF SUPPLY SERVICE RATES PROVIDE ADEQUATE INCENTIVE FOR LARGER C&I CUSTOMERS TO CONSERVE ENERGY?

A. We support rates that reflect the costs of providing that service. As stated above, however, declining block rates, or other rate designs that lower costs with increased usage, are counter-productive with respect to conservation. If industrial and commercial customers impose less distribution costs on the utility (and the conventional wisdom is that they do) then larger customers' rates should tend to reflect that cost differential. On the other hand, large C&I customers' electric charges are so substantial that they certainly have a cost incentive to invest in conservation and energy efficiency – and most do. More could be done, however, if those customers received prices that tracked the cost of providing the electric energy they consumer.

Q. DOES THAT COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

St. No. 1SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

SURREBUTTAL TESTIMONY OF
FRANK P. LACEY

On Behalf of Direct Energy Services, LLC

Duquesne Light Company Base Rate Case
Docket No. R-00061346

August 16, 2006

RECEIVED
SEP 2 8 2006
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Frank Lacey. My business address is 263 Tresser Boulevard, 8th Floor, Stamford, CT 06901.

Q. ARE YOU THE SAME FRANK LACEY WHO SUBMITTED DIRECT TESTIMONY AND REBUTTAL TESTIMONY ON BEHALF OF DIRECT ENERGY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE SUBJECT OF YOUR SURREBUTTAL TESTIMONY?

A. I wish to respond to some of the statements made by Neil Fisher, on behalf of Duquesne Light, Roger Colton, on behalf of OCA, and Mr. Brian Kalcic, on behalf of OSBA.

<u>Response to Mr. Neil Fisher's Rebuttal Testimony</u>

Q. MR. FISHER ASSERTS THAT DUQUESNE LIGHT HAS THE MOST SUCCESSFUL RETAIL CHOICE PROGRAM IN THE STATE AND ONE OF THE MOST SUCCESSFUL IN THE COUNTRY AND CLAIMS THAT "GIVEN DUQUESNE'S SUCCESS, THERE CERTAINLY IS NO 'DIRE NEED' TO ADDRESS SUGGESTED IMPROVEMENTS TO ITS RETAIL ACCESS PROGRAM IN A DISTRIBUTION RATE CASE." DO YOU AGREE WITH MR. FISHER?

A. No. Duquesne's retail choice program can be judged to be successful against the other Pennsylvania programs and against some others in the country. However, the Duquesne program pales in comparison to New York and Texas, especially for residential customers. Texas has more than 20 companies offering products to residential customers.[1] The New York Public Service Commission website shows numerous residential suppliers serving in several of the territories in that state, including 12

[1] See Texas Retail Choice website: www.powertochoose.org.

suppliers licensed to serve residential customers behind Consolidated Edison.[2] In both Texas and New York, residential shopping is increasing on a regular basis. These are the markets that should be viewed as the benchmarks for retail competition against which any meaningful competitive effort is compared. It is meaningless to compare Duquesne to the other large Pennsylvania utilities where there is virtually no customer choice occurring.

Certainly, for Mr. Fisher to claim that because of this alleged success, we should leave the program alone for another day, until the next POLR filing misses the point. In this case, Direct Energy has shown that Duquesne has not properly allocated to POLR most distribution related costs which are plainly associated with POLR service. Importantly, neither Mr. Fisher, nor any other witness disputes the fact that some portion of these costs – which Duquesne has labeled as distribution related – are in fact associated with providing POLR service. Both Mr. Fisher and other witnesses raise essentially policy issues as reasons why these costs should not be allocated to the service that causes the Company to incur them – POLR. These are not POLR issues, rather they are distribution issues – Duquesne Light is over-collecting its distribution rates and using those over-collections to subsidize its POLR service. The over-collection is inconsistent with basic notions of cost allocation and, I am informed, the mandates of the Choice Act. Certainly, if a particular rate class was subsidizing another, it would not be sufficient to suggest that the subsidy need not be eliminated because it looks like the rate class that is overpaying is "doing ok." Moreover, if the over-collection of distribution costs is

[2] See NY PSC website: http://www3.dps.state.ny.us/e/esco6.nsf/Web4?SearchView&SearchOrder=4&Query=%5BServesType%5D=Electric+Residential+AND+%5BTerritory%5D=1002.

allowed to continue, it will enable Duquesne to maintain a monopolistic stronghold over its residential and small commercial customers. The distribution rate case before us today is the appropriate forum to define the appropriate amount of distribution costs that Duquesne should be allowed to collect in its distribution rates.

Q. MR. FISHER CLAIMS THAT DUQUESNE'S POLR III RATES WERE DETERMINED BY THE COMMISSION TO REPRESENT "PREVAILING MARKET PRICES FOR THE FIRST THREE YEARS." THIS IS CONTRARY TO YOUR STATEMENT THAT DUQUESNE'S RATES WILL ALWAYS BE BELOW MARKET. HOW DO YOU RESPOND?

The Commission did rule in POLR III that Duquesne's POLR III rates represented prevailing (at the time) "market prices" – for power. But the Commission is required to set the POLR rates to reflect prevailing market prices for power *plus* all associated (reasonable) costs. In POLR III, the Commission declined to allocate to POLR costs embedded in Duquesne's distribution rates because it concluded that it did not have a sufficient record or time to do so (rates had to be in place by January, 2005). Those restraints do not exist here.

Until the POLR prices are fully reflective of all of the costs that are included in POLR service, those rates will always be "below market," i.e., below the full market price of selling power to a retail customer (including all customer care costs and the costs of delinquency). The PUC's prior ruling was that the POLR rates it approved reflected the market price of the power only. Unless all costs are included in such a "power only" POLR price, it will always give Duquesne an unfair cost advantage against all other market participants. It is a simple concept. Clearly, any supplier has those costs, plus some others. Therefore, under the current distribution rates and the rates proposed by Duquesne in this case, Duquesne Light as POLR supplier will always have an anti-competitive pricing advantage over the competitive supply companies in the market.

Q. MR. FISHER INDICATED THAT RETAIL SHOPPING IN DUQUESNE'S SERVICE AREA HAS REMAINED STABLE OR INCREASED OVER TIME. HE SUBMITTED AN EXHIBIT SHOWING SHOPPING LEVELS NEAR 60% OF TOTAL LOAD ON A KWH BASIS. DOESN'T THAT IMPLY THAT THE RETAIL MARKET BEHIND DUQUESNE LIGHT IS VERY ROBUST?

A. No. The numbers, charts (Exhibit NSF-1) and graph (NSF-3) put forth by Mr. Fisher are very misleading. First of all, Exhibit NSF-1 is not fully forthright, as it neglects many of the facts presented in the state websites and those that are well documented within the industry. For example, in the Consolidated Edison territory, Mr. Fisher's chart (Exhibit NSF-1, page 1 of 3) claims that residential shopping is only at 8%. However, according to the New York website that details electricity shopping statistics, 185,000 residential customers have chosen an alternative supplier (approximately two times the amount of Duquesne Light customers). Additionally, residential shopping in the Consolidated Edison territory has increased by 162% from June 2005 levels. Residential shopping in Duquesne's territory has decreased every quarter since January 2001.[3]

Further, in the large customer portion of Mr. Fishers charts (NSF-1, Page 3 of 3), there are two glaring problems. The most glaring problem with Mr. Fisher's analysis is that he completely <u>omits the state of Texas</u> from his analysis. Texas is widely acknowledged as having the most competitive retail market in the country. However, when Mr. Fisher analyzes "Large Customer" shopping, he neglects to include the Texas shopping rates in his graph, and somehow arrives at the conclusion that Duquesne has the highest percentage of large customers shopping in the country.

Additionally, Mr. Fisher ranks Duquesne's customer switching statistics as both first place in the country at 95% switching and 14^{th} place with 87% switching. Mr.

[3] See PA OCA website: http://www.oca.state.pa.us/cinfo/instat.htm.

Fisher footnotes both of these rankings with a caveat that jurisdictions differ in their measurements, but it is curious, nonetheless, how any company's shopping could hold two rankings in any singular category. These two oddities give rise to several serious questions about the validity of Mr. Fisher's data.

Q. ARE THERE ANY PROBLEMS WITH THE DATA THAT MR. FISHER PRESENTED IN HIS EXHIBIT NSF-2?

A. Yes. The primary problem with that graph is that Mr. Fisher makes no distinction between residential and C&I customers. The increase shown in 2005 is largely the result of the expiration of POLR I pricing. Residential shopping behind Duquesne, which is completely neglected by Mr. Fisher, has declined steadily since its peak in 2001. According to the Pennsylvania Office of Consumer Advocate, more than 176,000 residential customers were shopping in January 2001. Since then, residential shopping levels have declined in every quarter, for five and one-half years.[4] As of July 2006, only 94,000 residential customers are shopping. This represents a decrease of nearly 50% from the high level of shopping. Clearly, contrary to Mr. Fisher's assertion, shopping has neither remained stable nor increased for residential customers. Exhibit FPL-2 details this steady decline in residential shopping.

As stated above, the large increase shown in 2005 on Mr. Fisher's exhibit is likely due to the expiration of the POLR I rate for some of the very largest customers in Duquesne's service territory. Also, Mr. Fisher neglects to analyze the impact of the addition of Duquesne Light Energy ("DLE") to the competitive market. The entry of DLE has also likely distorted the shopping figures. There is suspicion in the market that

[4] See OCA website: http://www.oca.state.pa.us/cinfo/instat.htm.

Duquesne Light's POLR rates might be subsidizing DLE as well.[5] Clearly, if DLE could offer customers the benefit of that subsidy, it would benefit the customers and, at the same time, hold Duquesne Light harmless. So Mr. Fisher's simplistic graph supporting his assertion that shopping is stable or has increased over time omits several very important facts.

Q. MR. FISHER CLAIMS THAT "A MAJOR PURPOSE OF RESTRUCTURING WAS TO UNBUNDLE COSTS INTO GENERATION, TRANSMISSION, AND DISTRIBUTION FUNCTIONS. DUQUESNE DID THAT AND NOW EGSS WANT TO RE-VISIT THE SAME ISSUES." HOW DO YOU RESPOND?

A. I agree with Mr. Fisher that a major purpose of restructuring was to unbundle costs into generation, transmission and distribution functions. I disagree vehemently that "Duquesne did that." There is no evidence that Duquesne has unbundled its generation costs from its distribution rates. In fact, Duquesne has stated in this case that the only costs that it applies to POLR service are the actual cost of energy and the taxes associated with those costs. It has also admitted that these are the only costs that it has removed from the "distribution" bucket. This is exactly the core issue that Direct Energy is concerned about in this case. Because Duquesne has not effectively unbundled generation costs from distribution rates, the distribution customers will continue to subsidize Duquesne's POLR operations, resulting in an anti-competitive advantage to Duquesne Light.

Q. MR. FISHER DOES NOT BELIEVE THAT THE COMMISSION SHOULD ATTEMPT TO UNBUNDLE CUSTOMER COSTS IN THIS PROCEEDING. HOW DO YOU RESPOND?

A. It is very easy to understand why Duquesne Light would not want to unbundle its customer care costs in this proceeding. Mr. Fisher seems to rely on the fact that EGSs do

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5 See generally, Testimony of Strategic Energy witness Ron Carrier.

not perform customer functions as the basis for his argument. His logic is flawed here. First, some EGSs perform billing, especially for the larger customers, but, whether or not they do, *Duquesne is charging all distribution customers for POLR billing.* Secondly, one of the primary reasons that EGS may utilize the billing services of the utility is because it is virtually impossible for an EGS to compete against the POLR service if the EGS does its own billing. This is specifically because the billing, collection and uncollectible costs (along with many others that were outlined in my direct testimony) that the utility bears are not properly allocated to POLR service. The proposed solution that I outlined in my direct testimony is that if Duquesne wishes to keep its POLR costs bundled, then it should perform all of the services for which it is collecting revenue. These services include billing, collections and an allocation of uncollectible expense recovery to EGS uncollectible expenses. To accomplish the latter, and as outlined in my direct testimony, the Commission should order Duquesne Light to adopt a purchase of receivables ("POR") program or fully unbundle it generation costs from its distribution rates.

Q. MR. FISHER ARGUES THAT UNBUNDLING CUSTOMER COSTS IS A LENGTHY AND COMPLEX PROCESS. HE CITES TO SEVERAL NEW YORK CASES TO SUPPORT HIS POSITION. HOW DO YOU RESPOND TO THIS?

A. Mr. Fisher has reached the right conclusion about the complexity of unbundling customer costs. He also cites to the appropriate cases. The New York unbundling cases were long and contentious. The ultimate resolution is that because unbundling all of the customer costs was so complex, the utilities in New York adopted purchase of receivables programs. This may well be the right policy conclusion for residential and small commercial customers in Pennsylvania as well. I urged the Commission in my direct testimony, and I will reiterate that suggestion here, to have Duquesne Light choose between the two options. Duquesne should be required to unbundle its customer care costs, or it should be required to offer all of the customer services that ratepayers purchase to EGSs that wish to participate in the Duquesne market, including a purchase of receivables program. Either of these two options helps facilitate the development of competitive electric markets for residential and small commercial customers. If Duquesne and the Commission choose the unbundling option, then the purchase of receivables should be mandated at least until full unbundling is accomplished, or in lieu of full unbundling.

Q. MR. FISHER OFFERS FIVE REASONS THAT A PURCHASE OF RECEIVABLES PROGRAM IS NOT NECESSARY IN DUQUESNE'S SERVICE TERRITORY. HOW DO YOU RESPOND TO HIS ARGUMENTS?

A. His arguments are largely flawed. His first argument is that virtually all delinquent receivables are associated with default service load. My first response is that this is not surprising. Because of the subsidies inherent in Duquesne's distribution rates, there is very little residential shopping in Duquesne, so the majority of <u>all</u> receivables (not just delinquent receivables) is associated with default load. Secondly, this "fact" actually supports my testimony that most of Duquesne's uncollectibles, while associated with the POLR portion of its charges, is being allocated to and collected in the distribution charges. Finally, Duquesne's POLR related uncollectibles might be lower if a POR program was adopted. With such a program, the EGS community would not have to apply the stringent credit standards that it would have to apply in the absence of such a program. In other words, if the playing field were levelized, the benefits of competition could be extended to all customers in the service territory. This would likely result in an overall decrease in system-wide uncollectible expense.

His second argument is counsel advised him that Duquesne could not disconnect a customer for non-payment of EGS charges. First, the PUC can and should alter that general rule in order to achieve the competition-advancing benefits of a POR program. Moreover, since by purchasing the receivables of an EGS the charges in effect become those of Duquesne itself, the rule arguably is not violated. The utility is not terminating service for nonpayment of an EGS's charges, but for its own. Finally, even if Duquesne cannot terminate for nonpayment of these purchased charges, it has several options available to it to mitigate this risk of nonpayment, such as changing the order in which it applies partial payments under consolidated EDC billing.

His third argument is that Direct Energy effectively seeks a guarantee that it will be paid 100 cents on the dollar for everything that the EGS bills the customer. He states that Duquesne, as the default supplier, is not afforded a similar guarantee. While Duquesne has no guarantee of 100% collection, the assertion is hardly true. In this current rate case, Duquesne is seeking an uncollectible expense in an amount that is likely to compensate fully Duquesne for its realized uncollectible expense for the foreseeable future. In some years <u>Duquesne will likely over-collect</u> on its recovery and in some years it may undercollect. Pennsylvania has no tracking mechanism or true-up mechanism for bad debt. However, it is highly likely, that in a market where suppliers are offering competitive products and services to its customers, the overall bad-debt rate of the Duquesne system will decrease because overall electric costs will decrease. Therefore, in implementing a POR program, Duquesne is more likely to be compensated appropriately for its realized uncollectible expense that it would without a POR program.

His fourth argument is that POR programs in New York apply a discount factor to the receivable being purchased by the utility. This is true. The discount factor varies across the utilities in New York from a discount of zero percent to a discount of nearly 2%. Orange & Rockland Utility accepted a POR obligation in Pike County, Pennsylvania with a zero percent discount. Duquesne could implement the same program.

Finally, Mr. Fisher questions the need for a POR program based on the high levels of shopping that already exists in Duquesne's territory. As stated above, residential shopping is on a five and one-half year negative growth trend, with shopping levels now only about 50% of what they were in January 2001. Duquesne needs to implement some positive market enhancements to reverse that trend. POR is one of the enhancement that could help stop that decline.

<u>Response to Mr. Roger Colton's Rebuttal Testimony</u>

Q. MR. COLTON IS OPPOSED TO BOTH THE UNBUNDLING OF UNCOLLECTIBLE EXPENSE AND THE IMPLEMENTATION OF A POR PROGRAM. HE CLAIMS THAT MISALLOCATING UNCOLLECTIBLE EXPENSE COULD RESULT IN NON-SHOPPING CUSTOMERS HAVING TO PAY TWICE FOR THE SAME EXPENSES. HE ALSO BELIEVES THAT POR PROGRAMS CAN LEAD TO CUSTOMERS BEING DISCONNECTED FOR EGS CHARGES THAT ARE UNREGULATED AND HIGHER THAN THOSE IMPOSED BY THE POLR PROVIDER. HOW DO YOU RESPOND?

A. It should first be noted that Mr. Colton was silent in his rebuttal on the issues of mis-allocation of uncollectible costs and other POLR related costs, thereby, implicitly acknowledging that the problem exists. Mr. Colton is correct that a <u>misallocation</u> of uncollectible expense could result in a non-shopping customer paying twice for the same expenses. That is no different than the <u>misallocation</u> in existence today and being proposed for the foreseeable future, where shopping customers are paying twice for the same customer costs because these costs are <u>not</u> unbundled from distribution rates. In the end state, to develop a competitive electricity market, costs need to be allocated correctly.

In order to protect against the potential double payment that Mr. Colton identified, Direct Energy suggested that Duquesne could implement a POR program. Mr. Colton doesn't like that solution either. Mr. Colton is opposed to both the solution proposed to eliminate the subsidy and an alternative solution to offset the impacts of the subsidy, yet he offers no alternative solutions to the problem of the cross-subsidy. It appears then that Mr. Colton wants only the status quo. However, for the reasons outlined above and in my direct testimony, the status quo, is not acceptable and it is not sustainable.

<u>Response to Mr. Brian Kalcic Rebuttal Testimony</u>

Q. WHILE MR. KALCIC AGREES THAT WHAT HE CALLS INCREMENTAL POLR RELATED COSTS SHOULD BE ASSIGNED TO POLR, HE OPPOSES ASSIGNMENT OF A PORTION OF DUQUESNE'S JOINT AND COMMON DISTRIBUTION COSTS TO POLR SERVICE. HE CLAIMS THAT REMAINING POLR CUSTOMERS WOULD HAVE TO COMPENSATE DUQUESNE FOR ANY SUCH COSTS THAT IT WAS NOT ABLE TO COLLECT AS A RESULT OF CUSTOMERS SWITCHING TO AN EGS (pp. 13-14). ARE HIS CONCERNS JUSTIFIED?

A. No. This is one of the fundamental tenets of restructuring – Restructuring will force the market, including the utilities, to become more efficient. First, Mr. Kalcic's concern presumes that joint and common costs are static and will not change as numbers of POLR customers change. In my experience, that is not always true, except in the short term. Duquesne incurs a variety of customer care and other POLR-related expenses that can be modified as numbers of POLR customers vary. These include call center employees, procurement personnel, risk management and trading personnel, and other overtime and part-time worker costs. Duquesne could also reassign employees who are assigned to customer care, for example, and train them to handle collections activities with the free time they have due to the reduction in calls caused by greater numbers of customers being served by EGSs. Or, additionally, by allocating these joint and common costs to all the services that cause the company to incur them, Duquesne will have an incentive to find innovative ways to utilize any resulting "excess capacity" that can't be eliminated, thereby creating more efficiencies. Again, if Duquesne is forced to compete on a level playing field with competitive suppliers, it will of necessity find ways to drive efficiencies in its business practices.

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. It appears to me that Mr. Fisher and Duquesne Light are trying to portray my testimony and the concerns of Direct Energy as being POLR-related. The testimony that I have presented in this distribution rate case is not POLR-related testimony. It is distribution rate case testimony. In this distribution case, Duquesne Light has put into its revenue requirement several million dollars that are not appropriately assigned to distribution. Direct Energy is not suggesting that these costs should be disallowed. I am only suggesting that they be re-allocated to POLR service as POLR costs. Direct Energy is vehemently opposed to having Duquesne Light collect these costs in its distribution rates without having any obligation to provide the services for which they are collecting these revenues. The Commission should order Duquesne to completely unbundle its generation related costs and include them in Duquesne's POLR rates or, in the alternative, require Duquesne to provide all of the services associated with its revenue collections.

Q. DOES THAT COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

Exhibit FPL-2
Declining Trend in Residential Shopping Rates in Duquesne Light Territory

Declining Trend in Residential Shopping Rates in Duquesne Light Service Territory		
PA OCA Electric Shopping Statistics Date	Number of Customers Shopping	Percentage of Customers Shopping
Jan-01	176,488	33.60%
Apr-01	175,160	33.40%
Jul-01	171,230	32.60%
Oct-01	164,218	31.30%
Jan-02	158,301	30.10%
Apr-02	155,143	29.50%
Jul-02	150,680	28.70%
Oct-02	143,564	27.90%
Jan-03	141,284	26.80%
Apr-03	138,644	26.30%
Jul-03	135,789	25.80%
Oct-03	133,311	25.40%
Jan-04	131,065	24.90%
Apr-04	129,592	24.60%
Jul-04	127,311	24.20%
Oct-04	124,854	23.80%
Jan-05	123,094	23.40%
Apr-05	121,916	23.10%
Jul-05	119,737	22.80%
Oct-05	117,401	22.41%
Jan-06	103,530	19.70%
Apr-06	97,321	18.50%
Jul-06	94,086	17.96%