

VOLUME II

DOCKETED
DEC 23 1997

R-00974104, R00974104C0001-

Duquesne Statement No. 5

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
James A. Lahtinen

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PA PUBLIC UTILITY COMMISSION
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Contents:

Regarding Unbundled Cost of Service, Rate Design, and
Calculation of Competitive Transition Charges

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DIRECT TESTIMONY OF JAMES A. LAHTINEN

I. QUALIFICATIONS

1 Q. Please state your name and business address.

2 A. My name is James A. Lahtinen and my business address is 411 Seventh Avenue,
3 Pittsburgh, Pennsylvania 15230-1930.

4 Q. By whom are you employed and what is your position?

5 A. I am employed by Duquesne Light Company ("Duquesne") as General Manager
6 of the Regulatory and Economic Analysis Unit.

7 Q. Please describe your responsibilities as General Manager of the Regulatory and
8 Economic Analysis Unit.

9 A. I am responsible for overseeing the Company's integrated resource plan, retail and
10 wholesale rates, and transmission pricing and policies.

11 Q. How long have you been employed by Duquesne?

12 A. I have been employed by Duquesne since 1991.

13 Q. What was your professional experience prior to joining Duquesne?

14 A. Prior to joining Duquesne, I was a consulting economist with Bower, Rohr and
15 Associates. Before that I was Manager of Regulatory and Economic Analysis at
16 Central Vermont Public Service Corporation. I have a B.A. and M.A. in
17 economics from the State University of New York at Plattsburgh and Albany,
18 respectively.

1 Q. Please explain your experience that is pertinent to the testimony you provide in
2 this proceeding.

3 A. I have worked for 20 years as a consultant or analyst for utility regulators and as a
4 manager for utility companies. My experience has included testimony and
5 analyses with respect to a wide range of matters, including incentive ratemaking,
6 embedded and marginal cost of service studies, electrical load forecasting,
7 prudence of nuclear plant cost and in service schedules, economic evaluation of
8 demand side management programs, financial analysis of cable television
9 franchise areas, economic analysis of nuclear plant abandonment decisions,
10 economic analysis of power purchase arrangements from utility and non-utility
11 generators, leasing arrangements between affiliated interests, cost of service
12 pricing of wholesale transmission service, review of market prices, and evaluation
13 of stranded costs.

14 Q. Have you testified previously in regulatory or judicial proceedings?

15 A. Yes. I have testified before the Federal Energy Regulatory Commission
16 ("FERC"), the New York State Public Service Commission, the New Hampshire
17 Public Utilities Commission, the Vermont Public Service Board, the New Jersey
18 Board of Public Utilities Control, the District of Columbia Public Service
19 Commission, and most recently (Docket No. C-00967749) before the
20 Pennsylvania Public Utilities Commission.

II. PURPOSE AND SUMMARY OF TESTIMONY

1 Q. What is the general purpose of your testimony?

2 A. My testimony addresses four major areas. First, I sponsor the Company's
3 unbundled allocated cost of service study and the unbundled tariffs designed to
4 recover such costs. In doing so, I support the approach the Company has taken in
5 unbundling transmission, distribution, ancillary service and generation costs by
6 customer class. Second, I explain Duquesne's approach to calculating Customer
7 Generation Credits ("CGCs") and Competitive Transition Charges ("CTCs")
8 based on actual market price data. Third, I describe the rationale underlying
9 Duquesne's proposed rate design and how these rates were calculated. Fourth, I
10 provide public data on market prices that corroborate the prices received by
11 Duquesne in its recent request for proposals.

12 Q. Do you address other subjects in your testimony as well?

13 A. Yes. My testimony addresses a number of related topics, including:

- 14 • Separation of *generation into market and above market* components
- 15 • Customer choice options under Duquesne's plan
- 16 • Compliance with the rate cap and other provisions of the Electricity
17 Generation Customer Choice and Competition Act (hereafter referred to as the
18 "Act")
- 19 • Modifications to Supplemental and Back-up rates and treatment of other
20 miscellaneous rates and riders.

1 I also sponsor responses to several of the required data items identified in
2 Appendix A to the Commission's order dated February 13, 1997 at Docket No.
3 M-00960890.

4 Q. Please summarize your major conclusions?

5 A. I reach four major conclusions corresponding to the primary purposes of my
6 testimony described earlier. First, I conclude that Duquesne's approach to
7 unbundling costs and designing rates to recover these costs fully complies with
8 the Act. Duquesne has unbundled its costs using methodologies consistent with
9 those used in Duquesne's most recent base rate proceeding, and with the guidance
10 regarding unbundling provided in FERC Order 888. Duquesne's cost allocation
11 and rate design methodologies comply with the Act because allocated costs are
12 not shifted on an inter-class or intra-class basis. Also, Duquesne unbundles
13 existing rates in a manner consistent with the rate cap provisions in the Act.
14 Duquesne's calculation of CTCs based on actual market price data meets the
15 "known and measurable" requirement for stranded cost determination in the Act.
16 Finally, Duquesne's proposed rate design provides Duquesne with a reasonable
17 opportunity to fully recover its stranded costs, consistent with the Act.

18 Second, I conclude that Duquesne's calculation of CGCs and CTCs based on
19 actual market price information provides customers with the proper incentives and
20 promotes fair competition. Duquesne's market-based methodology insures that
21 customers receive efficient price signals in determining whether to purchase
22 power from alternative suppliers. If the customer generation credit is less than the

1 actual market price, customers will stay with the host utility for the wrong reason;
2 conversely, if the CGC is higher than actual market prices, customers will have an
3 artificial incentive to choose another supplier. Duquesne's approach to CGC
4 calculation relies on "known and measurable" market evidence as opposed to
5 administratively determined market price forecasts. As Mr. Schnitzer describes,
6 these forecasts of market prices have routinely proven to be materially inaccurate.
7 Instead of such forecasts, Duquesne will conduct an annual solicitation to sell firm
8 power to establish the market value each year for purposes of determining a CGC
9 and CTC that is fair both to customers and shareholders.

10 Third, I conclude that Duquesne's innovative rate design provides customers
11 with several key benefits and should be approved by the Commission. In
12 addition to rate unbundling, Duquesne proposes to redesign the manner in which
13 it recovers costs from customers. This new rate design will lower usage charges
14 to levels that more closely resemble market levels and will increase economic
15 efficiency. Under most of Duquesne's current tariffs, the rate for incremental
16 consumption significantly exceeds the additional cost of supplying increased
17 usage during most, if not, all hours of the year. Rate redesign will send customers
18 more efficient price signals and encourage economic load growth. Duquesne's
19 proposal reduces rates relative to current levels on average by over 25% for all
20 customer consumption above 1996 levels. Lower usage charges are consistent
21 with the objectives of Sections 2802 (6) and (7) of the Act to increase
22 competitiveness and economic development in Pennsylvania. Equally important,

1 rate redesign will provide additional stranded cost mitigation. This is because
2 increases in usage due to lower marginal rates will generate additional revenues
3 that, under Duquesne's plan, will be used for stranded cost mitigation. I estimate
4 that the proposed rate redesign provides an opportunity to further mitigate
5 stranded costs by approximately \$15 million per year.

6 Fourth, publicly available data on market prices show that the market price of
7 power in the markets in which Duquesne competes is below 2 cents per kWh.
8 The data support the prices revealed in Duquesne's recent competitive market
9 solicitation, where the weighted average of the winning bids was 1.816 cents per
10 kWh (75% load factor) for firm power sold in 1998.

11 Q. That summary was helpful. Please also explain whether there is a common
12 philosophy that underlies Duquesne's cost unbundling and rate design proposals.

13 A. Duquesne's philosophy is to meet, in the context of a restructured environment,
14 the long held ratemaking goals of allocating costs and pricing electric service in
15 an efficient and fair manner while at the same time allowing shareholders a
16 reasonable opportunity to recover prudently incurred costs. To accomplish this,
17 Duquesne has unbundled its tariffs on the basis of embedded costs and traditional
18 allocation principles.

19 Duquesne's proposal also recognizes that regulation is imperfect and that,
20 wherever possible, the Commission should rely on the market, particularly with
21 respect to the calculation of stranded costs. Duquesne's proposal does so by using
22 a market sale of firm power to establish the Customer Generation Credits that will

1 be used to establish CTCs. This approach should not only minimize disputes over
2 stranded cost "estimates," but also provide other important public benefits, such as
3 increasing the liquidity and competitiveness of the retail market by making
4 available to potential retail suppliers a portion of *Duquesne's firm power*.

III. OVERALL APPROACH TO UNBUNDLING

5 Q. Please describe Duquesne's overall approach to the unbundling of services.

6 A. As required by the Act and FERC Order No. 888, Duquesne will unbundle and
7 develop separate charges for distribution, transmission, ancillary services and
8 generation-related costs. As both Mr. Marshall and Mr. Clayton describe, the
9 starting point for Duquesne's approach is Section 2804 (4)(v) of the Act, which
10 states:

11 "If an electric distribution utility rolls its energy cost rate into base
12 rates at a combined level that does not exceed its combined level of
13 such rates which have been approved by the Commission as of the
14 Effective Date of this chapter, the utility shall not be required to
15 reduce its capped rates below the capped level upon the complaint
16 of any party if the Commission determines that any excess
17 earnings achieved under the cap are being utilized to mitigate
18 transition or stranded costs for the benefit of ratepayers or to offset
19 other known and measurable cost increases that would be
20 recoverable under traditional ratemaking but are not included
21 within the capped rates."

22 Pursuant to this provision, and as described by Mr. Clayton, Duquesne is rolling
23 into current base rates an energy cost rate ("ECR") that is cost-justified and equal

1 to the ECR cap approved by the Commission as part of the Ft. Martin plan. In
2 addition, Duquesne is committing to accelerate the depreciation and amortization
3 of stranded costs in an amount that, when added to other test year revenue
4 requirements, will result in a total revenue requirement equal to the rate cap. Mr.
5 Schnitzer provides further support for why Duquesne is entitled to the rate cap
6 during the transition period. As a result, new unbundled rates are designed to be
7 revenue neutral (adjusted for the ECR roll-in). This will insure that customers
8 who purchase power from Duquesne will pay no more than current rates for test
9 year volumes.¹

10 The next step after calculating baseline revenue requirements is to develop
11 cost-justified rates for the regulated services of transmission and distribution that
12 Duquesne will continue to provide all customers. Duquesne has developed rates
13 for each of these services on the basis of Mr. O'Brien's functionalized cost of
14 service study for the test year and allocation factors consistent with those used to
15 support current rates. Duquesne also has developed rates for certain transmission-
16 related "ancillary services." While customers are not required to purchase all of
17 these services from Duquesne, the FERC has ordered utilities to file cost-based
18 rates for these services and to offer them on a nondiscriminatory basis.

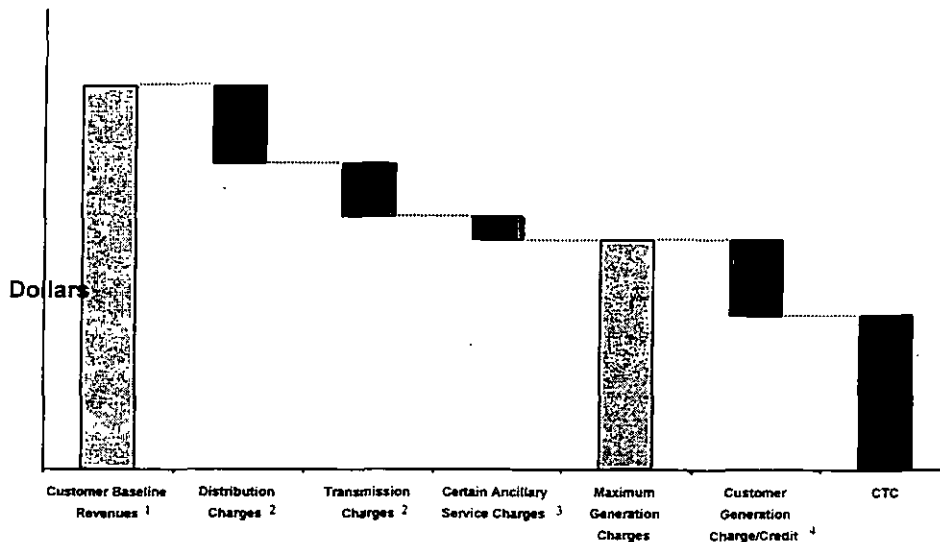
¹ Since loads are expected to grow over time, average revenue per kWh is likely to decline relative to current levels due to Duquesne's proposed lower usage charges.

1 Q. You have briefly described how Duquesne has unbundled transmission,
2 distribution and ancillary services. Please summarize how Duquesne has
3 unbundled generation costs.

4 A. Duquesne has unbundled generation costs and provided a calculation of the
5 generation-related revenue requirement allocated to each customer class.
6 Duquesne does not expect, however, to be able to fully recover its generation
7 revenue requirement over the transition period due to the rate cap provisions in
8 the Act. Therefore, generation-related revenues will be capped, and the rates
9 developed using a "residual" calculation method. By this I mean that, once
10 Duquesne has established rates for transmission, distribution and ancillary
11 services, these charges will be deducted from current rates and the remainder will
12 represent the maximum generation costs that can be recovered from customers.

13 This residual amount will then be divided into two parts -- a market-based
14 generation component ("CGC") and an above market cost component. The CGC
15 will be set using the market values from Duquesne's annual competitive bid
16 solicitation; these market prices will be adjusted to account for differences among
17 customer class consumption patterns, transmission losses, and Pennsylvania gross
18 receipts tax. As adjusted, the market prices will be used to determine customer
19 class CGCs and customer-specific CTCs. Customers will also receive annual
20 credits for certain ancillary service revenues collected from retail suppliers.
21 Duquesne's approach to unbundling is illustrated in the graph below:

Duquesne Unbundling Methodology



- 1) Current rates at customer 1996 baseline consumption with roll in of ECR and STAS credits.
- 2) Based on 1996 COS study and customer class allocation methodologies.
- 3) Certain ancillary services – reactive supply, regulation and frequency control, and spinning reserve – will be charged directly to all retail customers and reduce the CTC.
- 4) The annual CGC will be determined by Duquesne's market sale of firm power each year. The revealed market price will be adjusted for customer class load shapes, transmission losses, and Pennsylvania gross receipts tax. The customers will also receive an annual credit for certain ancillary service revenues collected directly from retail suppliers.

1 This unbundling methodology is applied consistently to total Company
2 1996 revenues as well as to charges for individual customers. I provide more
3 detail on how the CTCs are developed later in my testimony.

4 Q. Please summarize how these unbundled charges will be applied to customers.

5 A. The unbundled charges will apply to all customers once the phase-in period
6 begins in 1999. All customers that remain with Duquesne as their power supplier
7 (either by choice or prior to having the option of retail access) will pay unbundled
8 distribution, transmission (including certain ancillary services), market-based
9 CGC and competitive transition charges. Customers that choose an alternative

1 electricity supplier will pay these same unbundled rates for delivery services (T,
2 D, and CTC). Power charges for these customers will be the result of negotiations
3 with or standard offers from their alternative supplier. Choice customers also will
4 receive an annual credit for ancillary service revenues that Duquesne collects from
5 retail suppliers.

6 Q. What unbundled charges will be applied to retail suppliers?

7 A. Retail suppliers will be responsible for supplying or purchasing generation and the
8 associated transmission losses necessary to serve their customers. Losses can be
9 purchased from Duquesne or self-supplied. Suppliers also have the option of
10 purchasing firm power in Duquesne's annual RFP process. In addition, electricity
11 suppliers will be responsible for Pennsylvania gross receipts tax, as required by
12 the Act, as well as certain ancillary services. These services include scheduling,
13 energy imbalance and supplemental reserves. Mr. Irvin (Duquesne Statement No.
14 7) describes Duquesne's proposal regarding ancillary services in more detail and
15 discusses why the proposal is consistent with FERC Order No. 888.

16 Q. Does Duquesne's approach to unbundling protect customers from paying twice
17 for current services – once to Duquesne and once to alternative suppliers?

18 Yes. As shown in the table below, unbundled rates can be separated into
19 two general cost categories – those paid to Duquesne for delivery service and
20 those paid to the customer's supplier:

SUMMARY OF UNBUNDLED CHARGES

Costs in Current Bundled Rates	Unbundled Charges	
	Duquesne Delivery Charges	Duquesne/Alternative Supplier Responsibilities ²
Generation Related Costs: <ul style="list-style-type: none"> • Market value of electricity • Above market value of electricity • Bundled ancillary services • Bundled average T and D losses 	<ul style="list-style-type: none"> • CTC (variable and fixed) • Certain ancillary services (reactive supply, regulation and frequency control, and spinning reserve)³ 	<ul style="list-style-type: none"> • Market value of electricity • Certain ancillary services (scheduling, energy imbalance, supplemental reserve)
+ Distribution Costs: <ul style="list-style-type: none"> • Distribution-related costs 	<ul style="list-style-type: none"> • Average distribution losses⁴ • Distribution-related costs 	
+ Transmission Costs: <ul style="list-style-type: none"> • Transmission-related costs 	<ul style="list-style-type: none"> • Transmission-related costs 	<ul style="list-style-type: none"> • Average transmission losses
+ Gross receipts tax	+ Gross receipts tax on the non-electricity supply portion	+ Gross receipts tax on the electricity supply portion
= Total Bundled Customer Bill	= Total Customer Delivery Charges	= Total Supplier Responsibilities

2 As the table demonstrates, customers will not be charged twice for the same
3 service when rates are unbundled. The next section of my testimony addresses
4 how unbundled costs are allocated to particular rate classes.

² It is assumed that suppliers, whether Duquesne or some other entity, will need to recover the costs associated with those listed in the supplier responsibility column.

³ These costs have been refunctionalized and are included in customer transmission rates.

⁴ Distribution losses have been refunctionalized and are included in customer distribution rates.

IV. THE ALLOCATION OF GENERATION, TRANSMISSION AND DISTRIBUTION REVENUE REQUIREMENTS AMONG CUSTOMER CLASSES

1 **A. Guidance from the Act**

2 Q. What guidance does the Act provide regarding cost allocation?

3 A. The most explicit reference to cost allocation is provided in Section 2808(A)
4 regarding competitive transition charges. This section of the Act states that “The
5 costs to be recovered shall be allocated to customer classes in a manner that does
6 not shift inter-class or intra-class costs and maintains consistency with the
7 allocation methodology for utility production plant accepted by the Commission
8 in the electric utility’s most recent base rate proceeding.” While there is other
9 language in the Act in Section 2804 regarding the rate cap provisions, these
10 provisions reference charges or rates, not cost allocations.

11 Q. Has Duquesne complied with this provision of the Act?

12 A. Yes. As I explain later in my testimony, Duquesne has allocated the
13 functionalized costs reported in the testimony of Mr. O’Brien to the rate classes
14 using methodologies that are generally consistent with those approved in our most
15 recent base rate proceeding.

16 **B. Past Cost Allocation Methodologies**

17 Q. Please explain the way costs historically have been assigned to classes under cost
18 of service regulation in the electric utility industry.

19 A. Cost allocation has generally followed a three-step process consisting of
20 functionalization, classification and allocation. Functionalization refers to the

1 process of breaking down the total cost of service among generation, transmission
2 and distribution. Other costs, such as general plant, are more difficult to directly
3 assign to a specific function because they arise as a common cost with the
4 provision of a bundled service. General plant-related costs are often assigned to
5 the three main functions based on gross plant or some other factor. While no one
6 method of assignment is perfect, the idea is to apportion general or common costs
7 in some reasonable proportion to the relative magnitude of costs assigned directly
8 to the three main cost functions. The next step is to classify the costs according to
9 demand, energy, and customer categories. Historically, transmission and
10 generation costs have been classified as either demand or energy-related, while
11 distribution costs generally have been classified as either customer or demand
12 related. Once costs have been functionalized and classified, they are then ready to
13 be allocated to the various rate classifications based on relative contribution to
14 demand, energy, number of customers or some combination of these factors.

15 Q. What is the result of this process?

16 A. The result is a fully allocated cost of service study that can be used to design rates
17 to recover Company revenue requirements.

18 Q. How did Duquesne approach cost allocation in the past?

19 A. Based on a review of the allocated cost of service study prepared by the Company
20 in its last base rate proceeding, it appears that the Company focused primarily on
21 the classification, as opposed to the functionalization of costs. While some costs
22 were, to a degree, implicitly functionalized in the cost of service allocation

1 program, the focus of the study is on classification and allocation of costs to
2 classes on the basis of demand, energy and customers. This emphasis on
3 classification is certainly acceptable when you are allocating costs and setting
4 rates on a bundled basis. As such, there was never any need for the Commission
5 to approve functionally unbundled costs for cost allocation and rate setting
6 purposes. Now that rates must be unbundled, the primary focus has shifted to a
7 detailed functionalization of costs because the Act requires functionally
8 unbundled rates for transmission, distribution, and generation.

9 Q. Please discuss the allocations related to each functional category.

10 A. First, as to unbundled generation and distribution costs, we have maintained, to
11 the extent feasible, consistency with the allocation methodologies used for
12 generation and distribution costs from our most recent base rate proceeding.
13 Second, while transmission costs were allocated on the basis of the average and
14 excess methodology in Duquesne's last base rate proceeding; in the current study,
15 transmission has been allocated to the classes using the 12 CP methodology. This
16 is the allocation methodology preferred by the FERC. In addition, the costs of
17 ancillary services were allocated using the 12 CP methodology to maintain
18 consistency with the allocation of transmission plant expense. While these small
19 differences exist due to FERC Order 888 requirements, the results from the
20 current study produce results similar to the ones that would otherwise be produced
21 using the traditional average and excess allocation methodology. Finally, as
22 explained in more detail later, Duquesne's approach to cost and rate unbundling

1 insures that the rate cap provisions of the Act are met without shifting costs within
2 or among rate classes.

3 Q. What is the basis for these costs?

4 A. The allocated cost of service results are based on 1996 test year costs. The
5 revenue requirements have been functionalized into generation, transmission, and
6 distribution cost categories. Using a 1996 cost of service study is consistent with
7 the Commission's "Appendix A" requirements, which require unbundled cost of
8 service information on the basis of 1996 test year costs. Using a current cost of
9 service study also is consistent with traditional ratemaking practice.

10 The remainder of my testimony sets forth how the 1996 functionalized
11 revenue requirements data were used to (i) allocate costs across customer classes,
12 and (ii) design rates to recover these revenue requirements.

13 **C. Transmission Cost Allocation**

14 Q. Please explain how transmission costs were allocated across rate classes.

15 A. Duquesne has allocated transmission costs across classes on the basis of
16 contribution to monthly coincident peak. This is appropriate because transmission
17 systems must be designed to carry loads occurring during the periods of highest
18 system demands and because the FERC requires a coincident peak demand
19 allocation.

20 **D. Distribution Cost Allocation**

21 Q. Were distribution costs allocated on the same basis as transmission costs?

1 A. No, because distribution costs are different from transmission costs in three
2 primary respects. First, distribution costs are assigned to customers depending on
3 the voltage level at which customers take service. Duquesne distinguishes
4 between customers served at the 23 KV sub-transmission and 23 KV/13.2 KV
5 primary distribution levels, and the 4 KV secondary distribution system. Second,
6 Duquesne has divided distribution costs into customer-related and demand-related
7 costs. This is because some distribution costs -- like those associated with meters
8 and line drops -- are closely related to the number of customers served, while the
9 size (and cost) of conductors and transformers correlate to local area demand. But
10 neither measure, customer nor demand, can be perfectly correlated to the costs
11 incurred because many components of distribution costs vary with both.

12 Nevertheless, recognizing the art of embedded cost allocation procedures,
13 the demand-related cost components are allocated to classes on the basis of class
14 non-coincident demand responsibility. Unlike transmission, demand-related
15 distribution costs are incurred to meet maximum demands on local distribution
16 circuits, which do not necessarily occur at the time of maximum system peaks.
17 *Depending upon the mix of customers, distribution circuits may experience*
18 *maximum demand during different seasons and at different times of the day. The*
19 *customer portion of distribution-related costs are allocated and assigned based on*
20 *the number of customers. This procedure is consistent with the approach taken by*
21 *Duquesne in its most recent base rate proceeding.*

1 **E. Generation Cost Allocation**

2 Q. Please turn to the allocation of generation-related costs.

3 A. Plant related generation costs were allocated among classes using the average and
4 excess method. Duquesne classified production plant revenue requirements into
5 energy-related and demand-related components. The energy-related component
6 of plant is allocated to rate classes on the basis of each class' proportion to average
7 system demand, while the demand component is allocated to the classes according
8 to the average and excess demand allocator (the difference between peak and
9 average demands). This methodology recognizes that production plant costs are
10 incurred for two purposes: to achieve lower energy costs and to meet system
11 demands.

12 Q. Does the current study allocate generation costs using a methodology consistent
13 with that used by the Company in its most recent base rate proceeding?

14 A. Yes.

15 Q. Do you have an exhibit which shows the results from your allocated cost of
16 service study?

17 A. Yes. These are included in Exhibit JAL-1. In addition, this exhibit provides the
18 class allocators used to distribute the costs among the classes.

19 **F. Ancillary Services Cost Allocation**

20 Q. Please describe the ancillary services you have unbundled?

21 A. I have unbundled the costs associated with the ancillary services that FERC
22 directed transmitting utilities to provide in Order No. 888. Those services are:

23 1. Scheduling, system control and dispatch

1 2. Reactive supply and voltage control from generation sources
2 3. Regulation and frequency response
3 4. Energy imbalance
4 5. Operating spinning reserves
5 6. Operating supplemental reserves.

6 Q. Has Duquesne filed rates for ancillary services at the FERC?

7 A. Yes. Duquesne complied with Order No. 888 by filing cost-based rates for
8 ancillary services.

9 Q. Is Duquesne proposing to use those rates for the unbundled charges to retail
10 customers at issue in this case?

11 A. Duquesne is using the same functionalization methodology that supports the
12 ancillary service revenue requirements on file with the FERC. This methodology
13 is described in detail in the attached FERC testimony of Peter A. Wybierala,
14 Exhibit JAL-2. With respect to the design of rates from this functionalized
15 revenue requirement, however, Duquesne is proposing certain modifications to
16 tailor ancillary service rate design to accommodate retail choice. Duquesne will
17 seek FERC approval of these modifications.

18 Q. Please turn to the development of the ancillary service revenue requirements.

19 A. For purposes of restructuring, the revenue requirements for each of the six
20 ancillary services were based on cost information for the test year 1996. In order
21 to develop revenue requirements for each ancillary service separately, we first
22 conducted a "mini" functionalization study to separate costs currently included in

1 the FERC system of accounts as either transmission or generation. Using this
2 study we allocated an amount of currently bundled costs to each of the six
3 ancillary services to recognize the associated cost of providing these services on
4 an unbundled basis. While scheduling involves identifying a share of labor
5 expenses already included as a transmission cost, the other services require a
6 refunctionalization of a portion of the generation costs into one of the five
7 remaining ancillary service categories.

8 Q. Please turn to the functionalization of costs for specific ancillary services.

9 A. I will first discuss scheduling service. Duquesne allocated the costs from FERC
10 account 556 on the basis of the share of salaries associated with transmission
11 scheduling after adjusting for fringe benefits. The resulting cost per schedule was
12 \$113, which Duquesne rounded down to \$100.

13 Q. Please turn to the costs for reactive supply.

14 A. The cost of reactive supply and voltage control was developed using a four step
15 process. First, four components of gross generation plant equipment were
16 identified with the provision of this ancillary service. These components are
17 generation unit step-up transformers, exciters, voltage regulators, and generators.
18 Second, the reactive component of these costs was determined by multiplying a
19 ratio of reactive output based on rated power factor times the gross plant
20 investment costs for these components. Third, the resulting amount was then
21 divided by gross generation plant investment to derive the percentage of total
22 generation plant used to supply reactive power supply and voltage control.

1 Finally, this percentage was multiplied by the plant-related revenue requirement
2 (excluding fuel related expenses) for all generation plant to determine the annual
3 revenue requirements.

4 Q. How were the revenue requirements for the other ancillary services computed for
5 the 1996 test year?

6 A. The cost for regulation and frequency response was based on a three step process.
7 First, based on the proposed NERC Generation and Control Performance
8 Standards, to be effective Feb. 1, 1998, Control Performance Standard No. 2
9 (CPS2) defines a method for calculating the factor L_{10} for a particular control
10 area. L_{10} represents the target Megawatt deviation that a control area should be
11 able to operate within, over 90% of the 10 minute intervals for ACE (Area
12 Control Error) in order to comply with CPS2. Duquesne believes that L_{10} which
13 is about 43 MW for the Duquesne control area, represents the amount of
14 generation that has to be set aside in order to follow load. This generation would
15 be supplied from Duquesne's fossil plants. Second, the amount of generation
16 associated with L_{10} was divided by the gross fossil generation plant investment in
17 megawatts, to derive the percentage of total fossil plant to supply regulation and
18 frequency response. Finally, this percentage was multiplied by the fossil plant
19 related revenue requirement to determine the annual revenue requirement
20 associated with providing this ancillary service.

21 The cost for energy imbalance is based on the hourly deviation between
22 scheduled power and metered load. For on-peak and off-peak deviations within

1 the band, energy can be paid back in kind or cash settlement at the Duquesne
2 system lambda energy rate. For deviations outside of the band, energy supplied
3 by Duquesne would be at the rate of 110% of, lambda or market price, whichever
4 is greater, and energy taken by Duquesne would be credited at the rate of 90% of
5 lambda.

6 The cost for operating reserves includes both spinning and supplemental
7 reserves. ECAR requirements mandate that member companies maintain at least
8 3% spinning reserves and 3% supplemental reserves for a total of 6% reserves in
9 excess of forecast daily peak load.

10 Spinning reserves relate to generating capacity that is immediately
11 available to respond to deviations in system frequency resulting from load
12 forecast error and/or system disturbances (generator outages) throughout the
13 control areas comprising the eastern interconnection. Duquesne provides spinning
14 reserves exclusively from fossil generation plant. The annual spinning reserve
15 requirement is 3% of the annual forecast peak load in megawatts. This amount is
16 divided by the gross generation fossil plant, in megawatts, to derive a percentage
17 of total fossil generation to supply spinning reserves. Multiplying this percentage
18 by the fossil plant related revenue requirement determines the annual revenue
19 requirement for providing this ancillary service.

20 Supplemental reserves relate to generating capacity that is available within
21 10 minutes to respond to deviations in system frequency, resulting from system
22 disturbances (generator outages) throughout the control areas comprising the

1 eastern interconnection. Duquesne provides supplemental reserves from
2 combustion turbine (CT) generation plant, and fossil plant during times when the
3 reserve requirement exceeds installed CT capacity. The annual supplemental
4 reserve requirement is 3% of the annual forecast peak load. For 1996, the
5 supplemental reserve requirement was 74 MW based on a system peak load of
6 2463 MW. This amount was satisfied with all 54 MW of Brunot Island capacity
7 and with 20 MW from Duquesne's fossil plants. The revenue requirements
8 associated with these production-based ancillary services are shown in Exhibit
9 JAL-1 (E), Page 1 of 2.

10 Q. Once you have determined the annual revenue requirements for each of these
11 services, how did you then allocate the costs to each customer class?

12 A. The costs associated with reactive supply and voltage control, regulation and
13 frequency response, and spinning reserves were allocated to the classes on the
14 basis of contribution to 12 CP. The costs associated with providing other
15 ancillary services were not directly allocated to customer classes because these
16 costs will be recovered primarily from retail suppliers.

17 Q. Given that you have already allocated generation costs, won't the allocation of
18 ancillary service costs to the classes result in an over-recovery of Duquesne's
19 generation revenue requirement?

20 A. No. The revenue requirements associated with those portions of generation plant
21 that have been re-functionalized as ancillary service costs were deducted from the
22 generation-related revenue requirement. This was done before those costs were

1 allocated to the customer classes. Ancillary service costs that will be recovered
2 from suppliers were deducted from the cost of service altogether. Therefore, there
3 will be no double-recovery of Duquesne's revenue requirement.

4 **G. Comparison of Cost Allocations to Revenues**

5 Q. You have now described the relevant cost allocations. Have you also compared
6 the total costs allocated to base year revenues for the customer and rate classes?

7 A. Yes. Exhibit JAL-3, Page 1 of 2, compares the fully allocated cost of service
8 results with billed revenues generated at current bundled rates for the 12 months
9 ending December 31, 1996. The results from the fully allocated cost of service
10 study indicate that costs exceed 1996 revenues by \$48.9 million for PaPUC
11 jurisdictional sales. Based on these results and given the rate cap provision of the
12 Act, Duquesne will be unable to fully recover its allocated cost of service. The
13 results also indicate this difference is almost entirely attributable to the variance
14 between allocated cost (\$716.6 million) and revenues (\$664.5 million) for the
15 general service customer class. There is little difference for either the residential
16 or lighting service categories. For residential, allocated cost of service is \$400.8
17 million while revenues were \$404 million in 1996. Lighting service has allocated
18 cost of \$17.3 million and revenues of \$17.1 million. The top half of page 2 shows
19 the results for the rate classes. The data reveals that with the exception of RS all
20 the major rate classes have costs that exceed or are close to actual revenues. For
21 RS, revenues (\$374.9 million) are about \$15 million (4.1%) above the allocated
22 cost of service.

1 Q. Given these results and the cap provisions of the Act, how do you intend to
2 allocate costs to individual rate classes?

3 A. For those classes where allocated cost of service exceeds base revenues, I have
4 reduced the generation component of unbundled costs to insure that the rate cap is
5 maintained and to avoid cost shifting among rate classes. Where costs are below
6 revenue levels, I have adjusted the generation component to meet, but not exceed,
7 1996 revenues. This is consistent with Section 2804(4)(v) of the Act, which
8 provides for the use of any "excess earnings achieved under the cap" to be
9 "utilized to mitigate transition or stranded costs for the benefit of ratepayers."
10 Reconciling costs to rate levels in this way insures that the unbundled rates I have
11 designed will produce revenues from any one class and in total that stay within
12 the confines of the rate cap.

13 Q. Is there anything else you would like to add about the results from the allocated
14 cost of service study?

15 A. Yes. The results shown on the top half of pages 1 and 2 are based on an equalized
16 rate of return approach (9.61% as computed by Mr. Clayton). I have made two
17 adjustments to these figures. First, I have adjusted the cost of service study for
18 the differences in rate of return arising from Duquesne's most recent base rate
19 proceeding. This adjustment allocates costs from general service towards the
20 residential and lighting classes and reduces the difference between allocated cost
21 and revenues for general service while increasing the revenues have been adjusted
22 to reflect the roll-in of the ECR into base rates costs assigned to the residential

1 and lighting customer classes. Second, revenues have been adjusted to reflect the
2 roll-in of the ECR into base rates. The bottom half of page 1 of Exhibit JAL-3
3 compares the adjusted cost of service results to adjusted 1996 revenues by
4 customer class. All three customer classes have costs in excess of revenues after
5 adjustments. A similar comparison for the rate classes is shown at the bottom of
6 page 2. Again, differences between allocated cost and revenues are on average
7 smaller than they are before adjustments. Finally, it should be pointed out that
8 Duquesne's current rates were based on a cost of service study almost 10 years
9 old. It should come as no surprise to find differences between allocated costs and
10 current revenues given the amount of time that has elapsed. In fact, I find the
11 current relationship between revenues and costs to be surprisingly close.

V. RATE DESIGN

12 Q. Please turn now to the rate design. How have you organized this portion of your
13 testimony?

14 A. This portion of my testimony has four major sections. First, I describe the
15 requirements of the Act pertaining to rate design and how Duquesne complies
16 with these requirements. Second, I discuss the rationale for Duquesne's rate
17 design approach. Third, I describe the manner in which rates have been designed
18 to recover from each class the revenue requirement allocated to that class.
19 Specifically, I describe the five major components of rates:

- 20 1. Distribution
- 21 2. Transmission

- 1 3. Ancillary services
- 2 4. Customer generation charge/credit (“CGC”)
- 3 5. Competitive transition charges (“CTC”) – both class-specific variable CTCs
- 4 and customer-specific fixed CTCs.

5 Fourth, I address customer choice options under Duquesne’s plan. Each is

6 discussed in turn.

7 **A. Compliance with the Requirements of the Act**

8 Q. Please summarize the provisions of the Act related to rate design.

9 A. There are several. The key provisions are summarized below:

- 10 • Section 2804 (3) of the Act instructs the Commission to “require the
- 11 unbundling of electric utility services, tariffs and customer bills to separate the
- 12 charges for generation, transmission, and distribution.”
- 13 • Section 2808 (A) states that “the costs to be recovered shall be allocated to
- 14 customer classes in a manner that does not shift inter-class or intra-class costs
- 15 and maintains consistency with the allocation methodology for utility
- 16 production plant accepted by the Commission in the electric utility’s most
- 17 recent base rate proceeding.”
- 18 • Section 2804 (4) contains subsections (I) and (II) that set rate caps on electric
- 19 utility rates and the term over which these caps shall apply. Specifically, the
- 20 Act sets a cap on total charges of an electric distribution utility for service to
- 21 any customer who continues to purchase electricity from the utility (“full
- 22 requirements customers”) at a level not to exceed the total charges previously

1 approved by the Commission. This rate cap on total charges is effective
2 through June 2001. In addition, the Act provides for a cap on the generation
3 component of the charges (including the CTC) for full requirements customers
4 for a period of 9 years from the effective date of the Act or until the utility is
5 no longer charging a CTC, whichever is shorter. Finally, for those customers
6 who purchase generation from a supplier other than the distribution utility, the
7 Act imposes a cap on the non-generation charges (excluding the CTC) through
8 June 2001.

- 9 • As described earlier in my testimony, Section 2804 (4) (v) allows utilities to
10 collect its capped rates if it rolls its energy cost rate into base rates and if any
11 excess earnings achieved under the cap are used to mitigate stranded costs or
12 to offset other known and measurable cost increases that would be recoverable
13 under traditional ratemaking.
- 14 • Section 2808 (4) pertaining to the recovery of the CTC states that “During the
15 transition period, electric utilities shall have the duty to mitigate generation
16 related transition or stranded costs to the extent practicable.”

17 The remainder of this section details how Duquesne’s rate design proposal
18 complies with these requirements.

19 Q. Has Duquesne unbundled its charges as the Act requires?

20 A. Yes, Duquesne is proposing unbundled tariffs that separately charge for
21 transmission and distribution service. In addition, Duquesne has unbundled its
22 generation costs into two primary components: a market-based CGC and CTC.

1 The CGC will be based on the market price established through an annual
2 competitive solicitation for those customers who continue to purchase power from
3 Duquesne. The CGC, along with unbundled charges for transmission, distribution
4 and ancillary services, will be subtracted from current rates to develop CTCs.

5 Q. Does Duquesne's proposed rate design shift inter-class or intra-class costs?

6 A. No. Duquesne's rate design utilizes customer-specific CTCs in order to prevent
7 cost shifting within and among customer classes. For those customers who
8 continue to purchase electricity from Duquesne, the unbundled rates will result in
9 the same bill the customer would otherwise pay under current bundled rates
10 (adjusted for the ECR roll-in) assuming 1996 sales levels. This is verified
11 through sample calculations in Exhibit JAL-4. In addition, Duquesne's non-
12 bypassable fixed CTC will help to insure that all customers pay their fair share of
13 stranded costs. And Duquesne's approach to determining CGCs based on actual
14 market prices also maintains fairness and efficiency by limiting the ability of
15 customers that have access to retail choice to shift costs onto those that do not yet
16 have retail choice. Finally, as the Act requires, Duquesne has maintained
17 consistency with the cost allocation methodology for utility production plant
18 accepted by the Commission in Duquesne's most recent base rate proceeding.

19 Q. Please explain how Duquesne complies with the Act's rate cap on generation and
20 total charges for customers that continue to purchase electricity from Duquesne.

21 A. Generation-related revenue requirements have been allocated to the classes using
22 a methodology that is consistent with the one used in Duquesne's most recent

1 base rate proceeding. However, the total rate cap provision of the Act prevents
2 the Company from fully recovering these costs from customers through CTCs.
3 CTCs were therefore designed as a residual component starting with total
4 revenues at current bundled tariff rates, subtracting transmission and distribution
5 charges and applying credits based on the actual market price of power. As a
6 result, total unbundled charges will exactly equal bundled charges at current rates
7 based on 1996 sales.

8 Q. You mentioned that the Act imposes a rate cap for the non-generation services for
9 those customers who purchase generation from an alternative supplier. How does
10 Duquesne satisfy this requirement?

11 A. While the wording in the Act is straightforward, its application is not. This is
12 because the PaPUC never approved unbundled charges before. In the past, the
13 Commission approved revenue requirements and rates designed to raise the
14 approved level of revenue requirements on a bundled basis. Therefore, Duquesne
15 has designed unbundled transmission and distribution rates based on the 1996
16 allocated cost of service using, to the extent feasible, allocations that are
17 consistent with those used in our last base rate proceeding (rate year ending
18 March 31, 1988). This rate cap on non-generation charges, based on the 1996
19 cost of service, will remain in effect through June 2001.

20 Q. Please turn to Section 2804(4)(v).

21 A. Yes. As Mr. Clayton describes, Duquesne is rolling into current base rates an
22 energy cost rate that is cost-justified and equal to the ECR cap approved by the

1 Commission as part of the Ft. Martin agreement. In addition, Duquesne is
2 committing to accelerate the depreciation and amortization of stranded costs in an
3 amount that, when added to test year revenue requirements, will result in a total
4 revenue requirement equal to the total revenues produced by current rate levels.
5 Mr. Schnitzer provides further support for Duquesne's proposal to comply with
6 this section of the Act.

7 Q. How does Duquesne comply with the "known and measurable" requirement in the
8 Act for calculating CTCs over the transition period?

9 A. This requirement is discussed in detail in the testimony of Mr. Schnitzer.

10 Q. How has the Act's requirement to mitigate stranded costs affected Duquesne's
11 proposed rate design?

12 A. It has had a significant impact on Duquesne's proposed rate design. As I
13 demonstrate later in my testimony, Duquesne's rate design will lower usage
14 charges to levels that more closely resemble market. This not only increases
15 economic efficiency; but relevant here, contributes to stranded cost mitigation.
16 To explain, the rate for incremental consumption under most of Duquesne's
17 current tariffs significantly exceeds the additional cost of supplying increased
18 usage during most, if not, all hours of the year. Rate redesign will send customers
19 more efficient price signals and encourage economic load growth. Duquesne's
20 proposal reduces rates relative to current levels by over 25% on average for
21 customer consumption above 1996 levels. Lower usage charges are consistent
22 with the stated objectives of the Act in Section 2802 (6) and (7) to increase

1 competitiveness and economic development in Pennsylvania. Equally important,
2 rate redesign will allow Duquesne to significantly mitigate stranded costs. This is
3 because increases in usage due to lower marginal rates will generate revenues that
4 would not otherwise be generated under the current rate design. I estimate that
5 rate redesign provides an opportunity to mitigate stranded costs by approximately
6 \$15 million per year. (See Exhibit JAL-5). Under Duquesne's proposal, as set
7 forth in Mr. Clayton's testimony, these additional revenues will be used to further
8 accelerate the depreciation and amortization of stranded costs.

9 **B. Rationale for Duquesne's Rate Design**

10 Q. What is the rationale underlying Duquesne's unbundled rate design?

11 A. Consistent with Section 2808(4), the critical objective of Duquesne's unbundled
12 rate design is to mitigate stranded costs to the maximum extent practicable.
13 While Duquesne could simply unbundle current rates into transmission,
14 distribution and generation components and leave the existing rate structure intact,
15 rate redesign is necessary to further mitigate stranded costs.

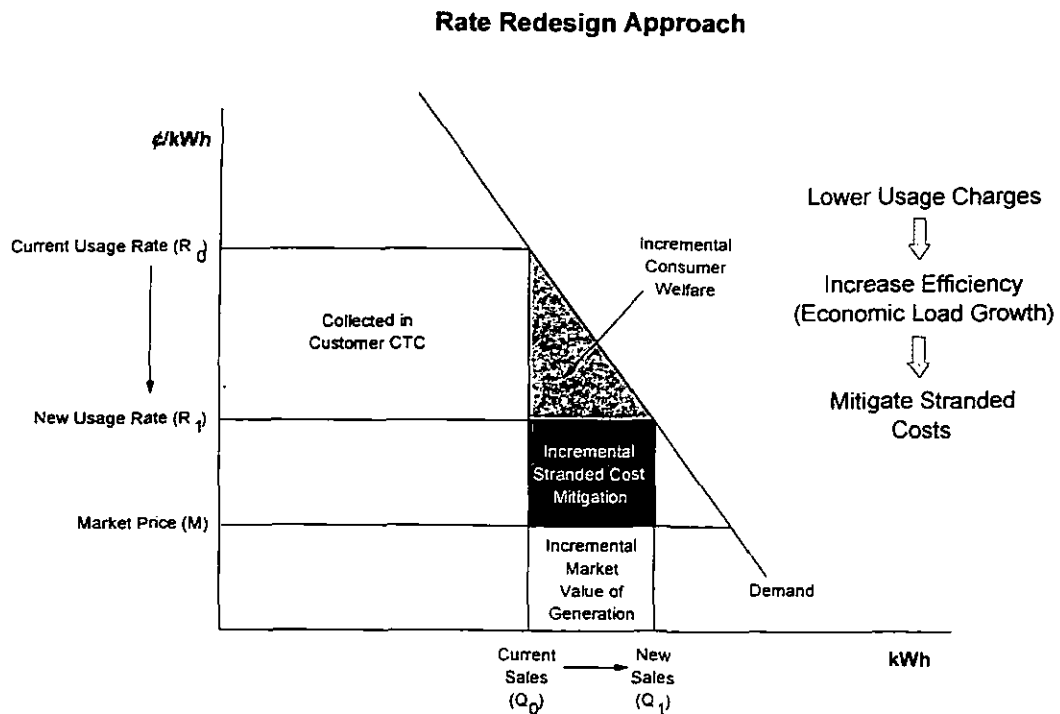
16 Q. You have stated that Duquesne's rate redesign proposal involves lowering usage
17 charges. Why won't this reduce revenues rather than increase revenues?

18 A. The reason is in the nature of the redesigned rates. The CTC will have two
19 components: a fixed customer charge and a variable charge. The fixed charge is
20 customer-specific and designed such that, when combined with the variable
21 charge and assuming consumption at existing levels, no customer will pay more
22 than he does today. The variable charge is designed to a level that will encourage

1 stranded cost mitigation by significantly lowering the charge associated with each
 2 kilowatt-hour of consumption. The variable charges contained in today's rates are
 3 significantly above market prices and the level that would maximize revenue
 4 recovery. For example, Duquesne currently charges a flat rate of 11.66 ¢/kWh to
 5 RS customers. This rate is in excess of the market rate of power and, equally
 6 important here, in excess of the rate that would maximize stranded cost
 7 mitigation.

8 Q. Why should the Commission approve this new rate design now?

9 A This rate design is mutually beneficial to consumers and investors. Customers
 10 will have an opportunity to save money by substituting electricity for more costly



11 forms of energy, and improve their quality of life by increasing their use of other
 12 electricity consuming goods and services. Customers and investors alike will

1 benefit from increased sales revenue because these revenues will be used to
2 mitigate stranded costs. The simplified graph below illustrates this concept more
3 fully:

4 In the illustration, Duquesne's proposal is to lower usage charges from R_0
5 to R_1 and recover the lost revenues through a CTC (equal to $[R_0 - R_1] * Q_0$) over
6 1996 customer baseline consumption. Lower usage charges will improve
7 resource allocation, as well as stimulate economic development, load growth and
8 jobs in the region. Residential, commercial and industrial customers will benefit
9 from the lower prices for consumption above baseline amounts. Meanwhile,
10 Duquesne will earn a contribution $(R_1 - M)$ on these increased sales $(Q_1 - Q_0)$ which
11 will be available to further mitigate stranded costs and possibly shorten the CTC
12 recovery period for all retail customers in Duquesne's service area.

13 The benefits that arise from a more efficient rate design could be
14 significant. For instance, Duquesne's proposal will effectively reduce marginal
15 rates on average by over 25% on customer consumption above 1996 levels, as
16 indicated in Exhibit JAL-6. Residential customers will receive a marginal rate
17 reduction of 50%. Equally important, Duquesne's rate design could mitigate
18 stranded costs by approximately \$15 million annually, depending on customer
19 load response to large decreases in marginal price signals. The more responsive
20 customers are to price changes, the larger the benefits will be. Exhibit JAL-7
21 illustrates that the potential annual mitigation could be significantly larger than
22 the \$15 million figure if customers respond more than expected.

1 Q. If moving rates closer to market levels increases economic efficiency, why
2 doesn't Duquesne lower its rates all the way to incremental costs or market
3 prices?

4 A. It is possible to reduce usage rates all the way down to market price levels through
5 time-of-use pricing or a real-time pricing program and achieve even greater
6 efficiency gains. However, most if not all of the fixed cost contribution and
7 stranded cost mitigation benefits would be lost as a consequence. Duquesne has
8 designed rates to enhance stranded cost mitigation to the maximum extent
9 practicable, as required by the Act.

10 Q. Electricity is generally thought to be an essential item with very little customer
11 sensitivity to changes in price. Why does Duquesne assume that customers will
12 increase consumption in response to lower usage rates?

13 A. While customer response is hard to measure precisely, a large body of economic
14 research in the industry and growing empirical results from real-time pricing
15 programs convincingly demonstrate that customers do respond to changes in
16 electricity prices. And while it may be true that customers do not respond as
17 much to price signals for electricity as they do for other commodities, it is
18 important to remember that relatively low customer response can still result in
19 significant stranded cost mitigation.

20 Q. How much customer response can be expected from lower electricity prices?

21 A. Customer response to price changes depends on many factors, so it is difficult to
22 generalize. However, three primary tools have been used by analysts to better

1 understand how customers might alter their consumption with changing prices.
2 These include econometric studies, simulation models, and consumer surveys.
3 Results from these studies vary, but general conclusions are possible. Most
4 evidence suggests that customer response could be large. Short term price
5 elasticities have been estimated to be in the range of -0.1 to -0.4. Price elasticity
6 is a ratio that measures the percent change in consumption per percent change in
7 price. These elasticities suggest that a 10 percent reduction in price will result in
8 roughly a one to four percent increase in consumption. Customer response tends
9 to be even higher (up to a -1.0 price elasticity) over longer periods since
10 customers are then able to more readily adjust appliance stocks and consumption
11 patterns over time. Therefore, as a result of Duquesne's proposed marginal rate
12 reduction of more than 25%, it is not unreasonable to expect that consumption
13 could increase above what it would otherwise be in the absence of rate redesign.

14 Q. What if there is no customer load response?

15 A. Very little would be lost. Even though Duquesne would not mitigate its stranded
16 costs from the proposed rate design, customers would be unharmed. In any event,
17 customers would still benefit from lower usage charges on new consumption.

18 Q. How important is it that the Commission approve this rate redesign now?

19 A. The potential benefits of rate redesign are both real and substantial. Duquesne's
20 proposed rate redesign represents one of the largest opportunities for Duquesne to
21 mitigate its stranded cost exposure over the transition period. And given the
22 rapidity of the move towards competition in the industry, the public interest

1 arguments in favor of rate redesign have never been stronger. Rate redesign
2 provides this Commission a golden opportunity to improve efficiency, increase
3 consumer welfare and enhance mitigation of stranded costs during the transition
4 to retail competition.

5 Q. Won't rate redesign be difficult to implement?

6 A. It is likely to be somewhat more difficult than a simple unbundling of rates, but
7 the benefits far outweigh any difference in administrative cost.

8 Q. Besides stranded cost mitigation, did you consider other criteria in developing
9 Duquesne's unbundled tariffs?

10 A. Yes, there are many criteria analysts use in the design of rates but three of them --
11 efficiency, fairness and adequacy -- stand out as primary under cost-of-service
12 based regulation. These criteria were first articulated by James C. Bonbright in
13 his book, Principles of Public Utility Rates (Page 292). Efficiency, which I have
14 already addressed, means that prices should reflect the added resource cost of
15 meeting incremental demand or, conversely, the resources saved when demand is
16 reduced. This criterion simply requires that prices be set on the basis of
17 incremental or marginal cost to avoid wasting society's resources. Fairness calls
18 for the benefits to follow costs so that the users who are responsible for costs
19 being incurred provide the revenue necessary to cover those costs. Adequacy is
20 necessary in order to insure that the utility investment devoted to the provision of
21 public service is not confiscated. Allowable charges must provide utility
22 investors the opportunity to recover their investment and to earn a fair return on it.

1 While Bonbright discusses other criteria, many are corollary to these three
2 primary criteria.

3 Q. Are these criteria consistent with the provisions of the restructuring Act?

4 A. I think they are. The Act provides for an orderly transition to competition towards
5 a deregulated generation market in a way that is fair to consumers, electric utilities
6 and their investors, and competitive suppliers. By adopting an orderly transition
7 process, the Legislature adopted a plan that recognizes the substantial financial
8 commitment made by utility investors under historical obligation-to-serve
9 requirements. In addition, the transition period allows utilities time to put into
10 place the necessary infra-structure to accommodate the creation of a competitive
11 generation market while maintaining a reliable electric system. The rate cap
12 provisions of the Act protect consumers who choose to continue taking electricity
13 from the distribution utility, while providing investors the opportunity to
14 accelerate amortization of above-market generation costs.

15 Q. Explain how Duquesne has attempted to meet the efficiency, fairness and
16 adequacy criteria?

17 A. Duquesne's redesigned rates improve efficiency since all consumers, including
18 those who remain as full requirements customers during the transition period, will
19 face prices for incremental changes in consumption that are much closer to market
20 levels. Duquesne's unbundled rate design is fair since it meets the rate cap
21 provisions of the Act, maintains current inter- and intra-class cost allocations,
22 gives customers credits based on actual market prices, and reduces the ability of

1 some customers to bypass their fair share of stranded costs. Duquesne's
2 unbundling of current rates also provides investors with an opportunity, not a
3 guarantee, to recover prudently incurred costs up to the rate cap.

4 Q. When will these unbundled and redesigned rates become effective?

5 A. The unbundled, redesigned rates will apply to all customers at the start of the
6 initial phase of retail access in 1999. Presenting all customers with the same rate
7 design makes sense for several reasons. First, it establishes rate comparability.
8 Second, Duquesne's rate redesign will provide customers the benefits of more
9 efficient prices for incremental usage sooner rather than having to wait until the
10 phase-in is complete. Finally, expanding this rate design to all customers
11 immediately will allow Duquesne to maximize mitigation of stranded costs by
12 encouraging worthwhile increases in electrical consumption.

13 Q. Are you saying that the Duquesne proposal is worthwhile even in the absence of
14 restructuring?

15 A. Yes. Any time rates can be redesigned to improve economic efficiency without
16 compromising the criteria of fairness and revenue adequacy, there is an
17 improvement in societal welfare, and this is exactly what the Duquesne proposal
18 is intended to do. There is no shifting of revenues to other classes or individual
19 customers because each customer will pay an amount equal to what he or she
20 would have paid under bundled rates for baseline consumption measured during
21 the base year (1996). Indeed, it is the same type of rate design Duquesne has used
22 for several years to encourage additional revenue growth from existing industrial

1 customers and new customers to move into Duquesne's service territory under
2 Rule 4.

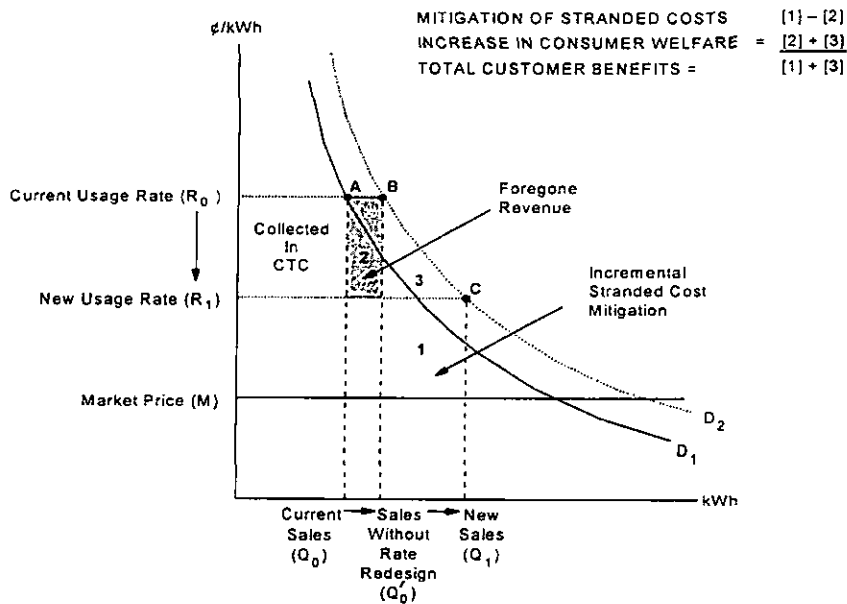
3 Q. You mentioned earlier that your primary rate design objective is to mitigate
4 stranded costs, and that you accomplished this objective by lowering current
5 usage charges (energy or demand). Please describe how you determined how
6 much to lower current usage charges.

7 A. Duquesne considered four factors to establish usage rate levels that mitigate
8 stranded costs:

- 9 • The market price
- 10 • Expected foregone revenue from load growth of existing customers without
11 rate redesign
- 12 • Customer load response to lower usage charges
- 13 • Current usage rate levels.

14 Each of these factors are illustrated in the graph below:

Determining Usage Rate Levels That Mitigate Stranded Costs



1

2 Q. Please describe how the first factor, the market price, was considered in
 3 determining the appropriate usage price.

4 A. The market price serves as the benchmark for determining usage rates. As a
 5 general rule, usage rates should not be set below the marginal cost of service, of
 6 which the market price is a key component. The contribution to stranded costs is
 7 measured relative to market prices. Incremental sales priced at usage rates above
 8 market levels (adjusted for other incremental costs such as losses) represent an
 9 opportunity to enhance stranded cost recovery (rectangle 1 above). Duquesne
 10 proposes to establish the market price through an annual RFP process. Pro-forma
 11 rates have been developed on the basis of Duquesne's recent RFP described in
 12 Mr. Irvin's testimony.

13 Q. Please explain the second factor – expected foregone revenue from load growth of
 14 existing customers without rate design.

1 A. Some existing customers would increase their load without rate redesign as a
2 result of changes in other factors unrelated to price. This is illustrated in the
3 above graph as a shift in the demand curve from point A to point B or an increase
4 in consumption from Q_0 to Q'_0 . Lower usage charges provide existing customers
5 with a rate cut for new consumption. This results in foregone revenues for
6 Duquesne (rectangle 2). Exactly how much revenue is lost depends on how much
7 usage rates are lowered, as well as expected load growth from existing customers
8 without any rate redesign. As a result, the net mitigation of stranded costs is equal
9 to the area of rectangle 1 less rectangle 2.

10 Q. How was customer load response to lower usage rates (price elasticity) considered
11 (represented in the graph as the difference in consumption between point C and
12 point B)?

13 A. In estimating the price elasticity, an extensive body of research was reviewed.
14 This research suggests that electricity is similar to most other commodities,
15 whereby decreasing prices tends to lead to greater consumption and increasing
16 prices tends to lead to less consumption, all other things being equal. In addition,
17 the Pennsylvania Legislature, the Governor and several intervenors have
18 highlighted the importance of lower rates for economic development and job
19 creation in Pennsylvania. For purposes of determining usage charges in this
20 proceeding, Duquesne assumed a conservatively low level of customer response
21 (i.e., a price elasticity of -0.1 for energy and -0.05 for demand). While Duquesne
22 recognizes the uncertainty regarding the exact level of customer response, the

1 potential benefits associated with even very low levels of customer response can
2 be significant.

3 Q. Did Duquesne perform any sensitivity analysis on its energy and demand
4 elasticity assumptions?

5 A. Yes. Exhibit JAL-7 shows that even with very low price elasticities, rate redesign
6 could yield \$5 million annually in stranded cost mitigation, while it would not be
7 unrealistic to achieve significantly higher benefits (above \$30 million) with larger
8 customer response.

9 Q. How did Duquesne consider current usage rate levels and determine what rates to
10 reduce?

11 A. Duquesne compared the existing effective usage charges (energy and demand) in
12 each of its rate classes with market prices. Where there was a significant
13 difference, these charges were lowered. For example, most residential customers
14 take service under rate RS. The current bundled rate schedule is a simple one
15 comprised of a fixed monthly customer charge of \$6.38 and an energy charge of
16 11.66 ¢/kWh for each kWh of consumption.⁵ Under Duquesne's new unbundled
17 tariff, customers who continue to take full requirements service will realize a 50%
18 reduction in the total usage (cents per kWh) charges, assuming a market price for
19 1999 of 1.86 ¢/kWh. Customers that can purchase electricity from alternative

⁵ These rates became effective July 26, 1997 reflecting the roll-in of the STAS credit into base rates.

1 suppliers for less than Duquesne's CGC could realize even greater savings on new
2 consumption.

3 Q. Is this situation different for commercial and industrial customers?

4 A. Yes. Many commercial and industrial customers take demand metered service.
5 For customers in these classes the energy charges are significantly lower than the
6 kWh charges for RS. Since these charges are much closer to efficient price levels,
7 they were not adjusted from current levels⁶. However, in a rate class like GL the
8 impediment to efficient electric consumption is high demand charges.

9 For example, Duquesne's current bundled rate for a GL customer is
10 comprised of demand and energy charges. The energy charge is 3.80 ¢/kWh for
11 all kilowatt-hour consumption. Demand charges are recovered on a declining
12 basis where the first 300 kW of demand is priced on a monthly basis at \$5,527.
13 For each kW of demand beyond 300 kW, the per kW charge is set at \$13.98.
14 While the energy rate is substantially below the comparable charge for an RS
15 customer, that is only part of the story. Because of the demand charge, a GL
16 customer's effective cost per kWh for incremental consumption is much higher
17 than 3.80 ¢/kWh. For example, assume that a GL customer with 1000 kW of
18 billed demand and monthly consumption of 380,000 kWh is considering
19 increasing demand by 1 kW. If the incremental demand is consumed at the
20 customers average load factor of 52.055% [(380,000/730 hrs.)/1,000 kW], the

⁶ It should be noted that high energy rates in initial blocks were reduced significantly for these customers as well, so that small commercial and industrial customers could benefit from lower usage charges.

1 effective price per kWh is 7.48 cents per kWh.⁷ The demand charge in this case
2 increases the effective kWh charge by almost 100%. This results in a usage
3 charge for incremental consumption that is significantly above market price levels
4 for a customer in this class of service. As a remedy, Duquesne reduced the
5 demand rates in this rate class by 50% from \$13.98 to \$6.99. This results in an
6 incremental usage charge (combined demand and energy) that more closely
7 approximates market prices. At this rate, the effective price per kWh is now 5.64
8 ¢/kWh, 25% lower than the current effective charge of 7.48 ¢/kWh.

9 Q. Please describe how the four factors mentioned above are interrelated and the
10 tradeoffs Duquesne faced in setting usage rates.

11 A. Determining appropriate usage rate levels is not an exact science. On the one
12 hand, the more you lower usage rates, the greater customer load response you
13 achieve. On the other hand, the more you lower usage rates, the lower is the
14 contribution on each additional kilowatt-hour you sell and the greater the foregone
15 lost revenue. Thus, there is a tradeoff between stimulating consumption and
16 reducing the contribution on increased sales. Duquesne's primary objective was
17 to mitigate stranded costs to the maximum extent practicable. This net revenue
18 would be available to shorten the CTC recovery period for all customers in
19 Duquesne's service area.

20 Q. Have you reflected the results of your analysis in your rate redesign proposal?

⁷ The effective price per kWh is computed by dividing the demand charge rate of \$13.98 by the associated monthly consumption, which is equal to the load factor (52.055 %) times the number of hours in the month (730).

1 A. Yes, by substantially reducing kWh and kW usage charges (approximately 50%)
2 for those classes where current rates are high relative to market value.

3 Q. Did Duquesne consider lowering certain energy and demand charges by more or
4 less than 50%?

5 A. Yes. However, this resulted in lower stranded cost mitigation due to the tradeoffs
6 just described. See Exhibit JAL-8.

7 Q. Does this mitigation of stranded cost represent the total efficiency benefits to
8 society?

9 A. No, consumers who increase consumption above 1996 baseline levels will receive
10 a welfare gain due to the lower usage rates, as represented by areas 2 and 3 in the
11 graph. This welfare gain, attributable to customers who value electricity more
12 than the usage rates being charged, could be large. Preliminary estimates indicate
13 that this consumer benefit is worth another \$15 million per year. As a result, the
14 efficiency gains from rate redesign could yield a total benefit to society of
15 approximately \$30 million (represented by the sum of areas 1 and 3 in the graph
16 above). About half of this figure is associated with the increase in consumer
17 welfare, while the other half represents stranded cost mitigation.

18 Q. What about customers that reduce their consumption below 1996 levels?

19 A. While these customers could avoid variable CTC charges, they would still be
20 responsible for paying their fair share of stranded costs through the fixed,
21 customer-specific CTC. These amounts are truly non-bypassable, as the Act
22 allows, and are based on 1996 consumption levels in order to prevent gaming.

1 Nevertheless, customers that reduce consumption will be able to benefit to the
2 extent that rate design allows the Company to mitigate stranded costs more
3 quickly.

4 **C. Design of Duquesne's Rates**

5 Q. Please turn to the design of rates for each of the unbundled services.

6 A. As I indicated earlier, current kWh and kW rates in many classes are significantly
7 above efficient price levels. Where this is the case usage sensitive rates were
8 reduced to "target" levels based on the stranded cost mitigation analysis just
9 described. These target levels represent the sum of the unbundled usage charges.
10 Target rate components were then functionally unbundled into distribution,
11 transmission, CGC and variable CTC components to recover the appropriate
12 amount of costs as indicated by the allocated cost of service study and market
13 valuation. The derivation of these unbundled rates is summarized in Exhibit
14 JAL-9.

1. Distribution Rate Design

15 Q. Could you please begin with distribution costs?

16 A. I will begin by developing the unbundled distribution charge for rate class RS.
17 Customers who take service under this tariff currently pay \$6.38 /mo. and 11.66
18 ¢/kWh for all consumption. Duquesne is proposing to reduce the delivered price
19 for power by 50% to 5.83 ¢/kWh under the redesigned and unbundled tariffs.
20 Backing out a CGC (market price of power) of 1.86 ¢/kWh, a customer will pay a

1 target delivery charge (T,D, and CTC) equal to 3.97 ¢/kWh. The distribution
2 portion of this delivery rate is determined by taking the distribution-related
3 revenue requirements (net of current customer charges) and dividing by total
4 target usage revenues. This ratio is then applied to the delivery rate. For
5 example, the allocated cost of service indicates that RS is responsible for \$83.6
6 million of distribution-related revenue requirements (net of current customer
7 charges). Meanwhile, the target delivery rate of 3.97 ¢/kWh will produce
8 revenues of \$118.3 million based on 1996 test year sales of 2,977,269 MWh.
9 The ratio of these two dollar amounts (approximately 71%) is multiplied by 3.97
10 ¢/kWh to determine the unbundled distribution charge of 2.81 ¢/kWh. This rate
11 when multiplied by the 1996 sales volume exactly recovers the allocated
12 distribution costs for RS, no more, no less.

13 Q. Did you follow the same procedure for the other rate classes?

14 A. Yes, however the mechanics are more involved because other classes currently
15 either have seasonally differentiated rates, block structures, demand charges or a
16 combination of all three features. For example, residential RAE and RAH tariff
17 customers have rates that vary by season for consumption in excess of 500 kWh
18 per month. During the summer months, all consumption is priced at 11.66
19 ¢/kWh, while in the winter only the first 500 kWh of consumption is priced at this
20 rate. Consumption in excess of 500 kWh is priced at 4.49 ¢/kWh.

21 Q. Can you demonstrate how distribution rates were unbundled for rate class RAH?

1 A. Yes. Rates were unbundled to preserve the seasonal blocking of the current
 2 tariffs. Just like RS, RH customers face usage rates that are high. Therefore,
 3 Duquesne has moved the summer kWh rate to 5.83 ¢/kWh (including the CGC) to
 4 encourage more efficient consumption. The tail block rate for usage in excess of
 5 500 kWh during the winter has been maintained at 4.49 ¢/kWh including the CGC
 6 (2.65 net of the CGC). During 1996, Duquesne billed 155,535 MWh at 11.66
 7 ¢/kWh and 153,666 at 4.49 ¢/kWh for usage in excess of 500 kWh during the
 8 winter months. The results from the allocated cost of service study indicate that
 9 RH is responsible for \$8.1 million of distribution-related costs. Dividing the
 10 distribution-related revenue requirements by the amount of revenue that would be
 11 derived at the target rate (\$10.3 million net of CGC and customer charge
 12 revenues) yields a ratio of approximately 79%. This percentage is then applied to
 13 the target rates to determine the unbundled distribution charges shown below:

Block	Target Rate (Net of CGC)	Percent	Distribution
1 st 500 kWh	3.99 ¢/kWh	79%	3.16 ¢/kWh
> 500 kWh	2.65 ¢/kWh	79%	2.10 ¢/kWh

14 Q. Do these unbundled rates recover the distribution-related revenue requirements for
 15 class RH?

16 A. Yes. These rates when multiplied by the 1996 billing determinants collect the
 17 exact amount assigned to rate class RH from the allocated cost of service study.

1 Q. Could you now describe how the distribution rates were unbundled for demand
 2 metered customers?

3 A. Yes. I will demonstrate how this was done using information for rate class GL.
 4 The currently effective rate structure charges \$5,527 per month for demand of 300
 5 kW or less, \$13.98 per kW for demand in excess of 300 kW per month, and 3.80
 6 ¢/kWh for all kWh consumption. Duquesne's rate redesign reduces the usage
 7 sensitive per kW charge 50% to \$6.99 and maintains the kWh charge at 3.80
 8 ¢/kWh including the CGC. Backing out the unbundled market price credit of 1.85
 9 ¢/kWh results in a target delivery charge of 1.95 ¢/kWh. Finally, Duquesne is
 10 retaining the monthly demand charge at \$5,527. A comparison of the current and
 11 proposed GL rate structures are shown below:

Block/Component	Current	Proposed
1 st 300 kW	\$5,527/mo.	\$5,527/mo.
> 300 kW	\$13.98/kW	\$6.99/kW
kWh	3.80 ¢/kWh	1.95 ¢/kWh plus market price or CGC

12 Q. Please explain how you unbundled the distribution charges for rate class GL.

13 A. As with the other classes, target delivery rates for each rate block were multiplied
 14 by the respective billing determinants to determine the amount of revenue
 15 recovery. Based on 1996 sales, these rate components recover \$128.8 million
 16 from GL customers. Distribution-related revenue requirements (\$36.0 million)
 17 are then divided by this amount to establish the percentage of distribution-related

1 costs recovered from each rate component. For rate class GL, that percentage is
2 equal to approximately 28%. Applying this percentage to the target delivery rate
3 components above yields the unbundled distribution-related rates by block and
4 type of charge:

Block	Target Rate (net of CGC)	Percentage	Distribution
1 st 300 kW	\$5,527	28.0%	\$1,546.19
> 300 kW	\$6.99/kW	28.0%	\$1.96/kW
kWh	1.95 ¢/kWh	28.0%	0.54 ¢/kWh

5 These unbundled rates exactly recover the allocated distribution-related revenue
6 requirement allocated to rate class GL.

7 2. Transmission Rate Design

8 Q. Please now describe how transmission rates were set for the various classes?

9 A. The approach for transmission is the same as described above for distribution.
10 For rate class RS, the transmission-related revenue requirement, \$13.4 million,
11 was divided by \$118.3 million (the product of the target delivery rate of 3.97
12 ¢/kWh and kWh sales for 1996) to determine the percentage of transmission-
13 related revenue requirements to total usage-related revenues. This percentage,
14 (about 11%) is then multiplied by the target delivery rate of 3.97 ¢/kWh in order
15 to establish the unbundled transmission charge of 0.45 ¢/kWh. This rate when
16 multiplied by the test year sales recovers the appropriate amount of transmission-
17 related costs from RS customers.

1 Q. Are the calculations more involved for the other classes?
 2 A. Yes, as with distribution, but the approach employed is the same. For example,
 3 the allocated cost of service study assigns \$1.4 million of transmission-related
 4 revenue requirements to rate class RH. From above we know that the amount of
 5 revenues recovered under the target delivery rate generates usage-related revenue
 6 of \$10.3 million. The ratio of these two numbers (about 14%) multiplied times
 7 the target rate levels produces the unbundled transmission rates by block as
 8 depicted below:

Block	Target Rate (net of CGC)	Percentage	Transmission
1 st 500	3.99 ¢/kWh	14%	0.52 ¢/kWh
> 500 (Winter)	2.65 ¢/kWh	14%	0.35 ¢/kWh

9 Q. How were transmission-related revenue requirements recovered from rate class
 10 GL?
 11 A. First, the share of transmission-related revenue requirements to total usage
 12 revenues was computed. This ratio was then multiplied by the block-specific
 13 target rate levels to determine the unbundled transmission rates by block and by
 14 component. For transmission, the percentage is about 8%. This results in the
 15 unbundled transmission rates depicted below:

Block	Target Rate (net of CGC)	Percentage	Transmission
1 st 300 kW	\$5,527/mo.	8%	\$429.56/mo.
> 300 kW	\$13.98/kW	8%	\$0.54/kW
kWh	1.95 ¢/kWh	8%	0.15 ¢/kWh

1 Q. Is this rate design for transmission the same as discussed in FERC Order 888 and
2 included in the pro forma tariff?

3 A. Not exactly, but it is consistent with traditional ratemaking practices, including
4 those utilized by FERC. The primary difference is that it recognizes certain
5 limitations on the metering of customer demands of residential customers.

6 Q. Please explain.

7 A. FERC's pro forma tariff uses two basic methodologies for allocating costs and
8 designing rates. The first is the methodology applicable to network service.
9 Under the network tariff, the utility's test year transmission revenue requirement is
10 allocated on a rolling twelve-month basis among network customers on the basis
11 of their contribution to monthly coincident peak demands. In essence, this is a
12 direct allocation of costs that avoids the need to develop unit rates based on
13 current or forecast usage.

14 The second methodology is that for point-to-point transmission service.
15 For this service, the utility divides its test year transmission revenue requirement
16 by some measure of coincident peak demand (annual CP, 4 CP or 12 CP). This
17 produces a unit rate per MW of demand. This rate is then billed to the customer,
18 on a take or pay basis, on the amount of its "reservation" of capacity.

19 Duquesne's proposed methodology is consistent with, but not the same as,
20 the FERC methodology. For example, Duquesne is proposing to allocate
21 transmission costs to customer classes using class contributions to monthly

1 coincident peak demands which is consistent with FERC use of CPs to allocate
2 costs to wholesale transmission customers. The only real difference is in the
3 design of the rates. With the exception of the rate redesign discussed previously,
4 Duquesne has designed customer transmission rates on a basis consistent with the
5 traditional methodologies used for these customers. For example, residential
6 customers are charged for transmission service on the basis of a per kWh charge,
7 rather than a kW charge, given that Duquesne at present has no demand meters
8 with which to measure their maximum hourly demands.

9 **3. Ancillary Services Rate Design**

10 Q. Please explain the rate design for ancillary services.

11 A. I will discuss each service in turn, with certain of the services grouped together
12 for convenience. The first group of services is reactive power, frequency
13 regulation, and spinning reserve. Consistent with FERC Order No. 888, and as
14 described by Mr. Irvin, these services must be provided by Duquesne unless, as to
15 the latter two services, dynamic scheduling is arranged. Given that the services
16 are a necessary adjunct to transmission service, and that most, if not all, customers
17 will be purchasing them from Duquesne, I have used the same rate design
18 methods for recovering the allocated costs of these services as I used to recover
19 the allocated cost of transmission service.

20 The remaining ancillary service rates for scheduling, energy imbalance
21 and supplemental reserves will be charged to suppliers who use these services.
22 The scheduling charge is a per unit charge applicable to all suppliers, as is the

1 energy imbalance charges and supplemental reserve charge. Using a single per
2 unit supplier charge for these services is appropriate because of the nature of the
3 services. The scheduling charge will vary with the scheduling practices of each
4 supplier, not the characteristics of any customer class. The same is true for energy
5 imbalance charge. Finally, suppliers have the option of supplying or purchasing
6 supplemental reserves from the market. A unit charge applicable to any supplier
7 taking the service is therefore appropriate. The per MW rate for this service is
8 developed by dividing the annual revenue requirement (\$9.9 million) associated
9 with providing this service by the MW (74) of capacity associated with providing
10 it.

11 Q. Does the provision of any of these ancillary services raise stranded cost issues?

12 A. Yes. The ability of electric suppliers to compete to provide supplemental reserve
13 service may cause Duquesne to fail to fully recover the revenue requirement
14 associated with the service. Duquesne has addressed this issue by recovering
15 these costs in the CTC. To ensure, however, that Duquesne does not overrecover
16 its revenue requirement associated with this service, Duquesne will flow through
17 to retail Choice Customers, on an annual basis, any revenues received from
18 electric retail suppliers that purchase this service from Duquesne (as opposed to
19 providing the service themselves). To the extent other ancillary services become
20 subject to competition, a similar approach to stranded cost recovery would be
21 adopted.

22

1 **4. Customer Generation Credit/Charge (“CGC”)**

2 Q. Please summarize the purpose of the CGC.

3 A. The CGC represents the competitive market value of a customer’s electricity
4 consumption, that is, the portion of the customer bill that a customer can avoid
5 when selecting an alternative electricity supplier. Duquesne’s CGC will be based
6 on actual market price information each year and therefore will provide
7 consumers with the proper price signals. This allows customers to decide on the
8 basis of unbiased information whether or not to leave Duquesne for an alternative
9 supplier. If the CGC is set below the actual market price, customers will have an
10 artificial incentive to stay with Duquesne. This result, could hinder competition
11 and retard the development of a competitive retail electricity market. If the CGC
12 is set above the actual market price, customers will have an artificial incentive to
13 leave Duquesne for another supplier, exacerbating efforts to mitigate stranded
14 costs. This is because when customers leave, Duquesne will be unable to sell
15 power at a price above market. This is why it is important that the CGC be based
16 on actual “known and measurable” market evidence as opposed to
17 administratively determined market price forecasts. Duquesne’s proposal to base
18 its CGC on an annual competitive market sale of firm power will allow Duquesne
19 to determine a CGC and CTC that sends efficient price signals and is fair both to
20 customers and shareholders.

21 Q. How is the CGC calculated?

22 A. The computation of the CGC involves four basic steps:

- 1 1. Establish the market value through the RFP process,
- 2 2. Determine hourly market values from winning bid prices using hourly price
- 3 shapes,
- 4 3. Calculate the market value for each class using customer class load shapes,
- 5 and
- 6 4. Adjust the class-specific market values for transmission losses and
- 7 Pennsylvania gross receipts tax.

8 Q. Why is it necessary to make adjustments for hourly price and customer class load
9 shapes?

10 A. The market value of the power contract may not provide an exact measure of the
11 market value of the customer's consumption since the customer and bidder may
12 consume (take delivery of) electricity during different hours in the year.
13 Therefore, in order to use the RFP contract price to estimate the market price
14 associated with a specific customer class consumption pattern, it is first necessary
15 to disaggregate the contract price into hourly market prices. This is necessary
16 because classes consume power at different times in varying amounts during the
17 course of the year. And since market prices depend on time-of-use, the value
18 Duquesne will realize by selling power that is released by departing load will
19 differ based on the characteristics of that load. Accounting for the difference in
20 market values enables Duquesne to appropriately credit the RFP market price to
21 each class.

22 Q. Could you provide an example?

1 A. Yes. Power is generally more valuable during the peak hours (daytime) than at
2 night and is similarly more valuable during the summer months than in either the
3 fall or spring. Therefore, a rate class that consumes a relatively greater proportion
4 of its total requirements during peak (high cost) periods will receive a higher
5 credit than classes that do not. This higher market price credit is appropriate since
6 these customers are more expensive to serve, and this market-based approach will
7 ensure that customers in all classes will have an equal opportunity to participate in
8 competitive markets.

9 Q. How is the hourly price shape information used?

10 A. The price shape defines the relationship of the price in each hour to the average
11 price for all hours in the year. When applied to the RFP contract price - along with
12 the contract minimum and maximum take provisions - the price shape gives a
13 market-based estimate of hourly market prices for the term of the contract. For
14 illustrative purposes, assume a simplified market where every hour has either "the
15 on-peak price" or "the off-peak price" and the competitive RFP contract reveals a
16 market price of \$18 per MWH for a 1 MW contract:

- 17 • Further assume that the purchaser takes the maximum amount during on-peak
18 periods and the remainder during off-peak hours in order to satisfy the 75%
19 annual capacity factor requirement in the RFP and to maximize value.
- 20 • Also assume that the price shape data indicates that the relationship of on-peak
21 to off-peak prices is 1.1976 to 1.

1 Given this information, the values for on- and off-peak prices can be determined
2 as follows:

Period	Avg. MW Load ⁸	Hours	RFP Purchaser Load (MWHs)	Ratio to Off-Peak Price	Revealed Bid Price in \$/MWH
On-peak (5 x 16)	1.000	4,160	4,160.0	1.1976:1	19.160
Off-Peak	<u>0.524</u>	4,600	2,410.4	1:1	<u>15.998</u>
Total	0.750	8,760	6,570.4	--	18.000⁹

(Note: Bold numbers are given.)

- 3 Q. How will Duquesne determine the hourly price shape for the year?
- 4 A. Duquesne's price shape data will be based on actual marginal cost data in each
5 hour for Duquesne for the most recent calendar year. These historical figures will
6 be known and measurable. Mr. Karl explains how the price shape will be
7 determined in his testimony in greater detail. While price shapes could vary in the
8 future, Duquesne does not expect the hourly price pattern to change significantly,
9 particularly in the near term. Currently, Duquesne is using actual 1996 marginal
10 cost data. However, Duquesne will update these price shapes annually to reflect
11 significant changes in actual hourly price patterns.

⁸ Based on the RFP's annual 75% capacity factor and an hourly minimum take of 50% of the contract amount.

⁹ This represents the bid for a 75% capacity factor contract. A comparable market price for a 100% baseload contract would be lower (\$17.3/MWH).

- 1 Q. How are the customer class load shapes used?
- 2 A. The third step in computing a CGC is to apply the derived hourly market prices to
3 customer class load shape data. This results in a single ¢/kWh credit for each
4 customer class. In the above example, if residential customers consume 70
5 percent of their energy requirements during on-peak hours and 30 percent during
6 off-peak hours, the credit for residential customers would equal 1.821 cents per
7 kWh ($70\% * 1.9160 + 30\% * 1.5998$). By comparison, if industrial customers on
8 average consume 50 percent of their energy requirements during on-peak hours
9 and 50 percent during off-peak hours, the credit for that class would be 1.758
10 cents per kWh ($50\% * 1.9160 + 50\% * 1.5998$).
- 11 Q. How are the customer class load shapes determined?
- 12 A. Due to the absence of hourly interval meters for all customers, Duquesne proposes
13 to employ hourly 1996 customer class load profiles based on sample metering
14 data. Hourly load profile meters have been collecting hourly load data on the
15 Duquesne system for several years from a sample of residential, commercial, and
16 industrial customers. The resulting load profiles are known and measurable and
17 will be used to calculate class-specific credits.
- 18 Q. What other adjustments are made to calculate CGCs?
- 19 A. The customer class market credits are adjusted for transmission losses and
20 Pennsylvania gross receipts tax.
- 21 Q. You mentioned an adjustment related to transmission losses. Would an
22 adjustment for embedded transmission costs also be appropriate?

1 A. No. These embedded cost charges are unlike the costs associated with
2 transmission losses, which can be competitively supplied. Under Duquesne's
3 tariff, electric suppliers must only purchase or supply transmission losses not
4 transmission service in order to sell at retail. Embedded transmission costs will
5 be collected from retail customers through unbundled transmission rates.
6 Therefore, it is appropriate to only credit transmission losses.

7 Q. You have discussed transmission losses. Would a similar adjustment be made for
8 distribution losses?

9 A. No. The cost of distribution losses is recovered as part of Duquesne's unbundled
10 distribution rate for all customers. Electric suppliers serving retail customers will
11 not be required to supply distribution losses.

12 Q. Some parties have suggested that an adjustment should be made to reflect avoided
13 retail marketing costs. Do you agree with that suggestion?

14 A. No. Duquesne has no material "marketing" costs that it would avoid with a loss
15 of retail load. Duquesne currently has an exclusive franchise to serve its electric
16 customers and thus does not "market" the sale of electricity to them in the manner
17 that will occur in a competitive market. In any event, if there were avoidable
18 marketing costs, a better approach would be to adjust the cost of service directly
19 as an offset to informational and educational costs incurred by Duquesne for
20 implementing retail choice, not through an ad hoc adjustment to market price.

21 Q. Is there any evidence that electricity suppliers need such ad hoc adjustments to
22 wholesale market prices?

1 A. No, not that I am aware of. In fact, most market evidence that I have seen from
2 retail access pilots to date indicates that suppliers are more than willing to serve
3 retail customers at levels very close to (or even below) wholesale market prices.
4 For example, a report filed in the Massachusetts pilot shows that the weighted
5 average retail price offered to residential customers was 2.22 ¢/kWh. Meanwhile,
6 the wholesale market price for NEPOOL in 1996 was higher at 2.41 ¢/kWh (based
7 on reported data in Power Markets Week). See Exhibit JAL-10.

8 Q. Do you make any other adjustments?

9 A. Yes. I adjust the credit for Pennsylvania gross receipts tax since suppliers will be
10 responsible for collecting this tax from their customers.

11 Q. How will the CGC be applied to individual customers?

12 A. The class-specific CGC will be multiplied by each customer's 1996 baseline
13 consumption. Thus, each customer electing retail choice will have a dollar credit
14 tailored to his or her historic baseline consumption. The size of the credit will
15 remain fixed during the rate year. The CGC will be recomputed each year based
16 on the results from the sale of firm power under Duquesne's RFP process.
17 Therefore, if market prices increase over the transition period, the CGC will
18 increase and the related CTC will decrease. Sample pro-forma CGCs are shown
19 in Exhibit JAL-11 for each rate class based on the most recent RFP sale of firm
20 power for deliveries in 1998.

1 **5. Competitive Transition Charges (CTCs)**

2 Q. You have discussed the rate design for distribution, transmission, ancillary
3 services and CGCs. Please describe your rate design proposal for the CTC.

4 A. The Act provides Duquesne with a reasonable opportunity to recover the stranded
5 costs associated with the transition to competition by allowing the Company to
6 charge customers in its service area for CTC revenue requirements whether or not
7 they continue to take electricity from Duquesne. CTC revenue requirements are
8 separately calculated and unbundled from other delivery costs. Duquesne is
9 proposing to recover CTC-related revenue requirements through two types of
10 charges: (i) rate class usage-sensitive CTCs (¢/kWh and \$/kW) and (ii) customer-
11 specific CTCs (\$/month). The total amount collected through the CTC is
12 calculated as a residual for each customer. The starting point is the customer's
13 baseline level of consumption in 1996 priced at current rates. These baseline
14 revenues are reduced, for distribution and transmission charges (including certain
15 ancillary services), and reduced by the CGC. The remaining amount is collected
16 through CTCs. (This approach was illustrated graphically earlier in my testimony
17 on page 10.)

18 **a) Class-Specific Competitive Transition Charges**

19 Q. Please describe how the class-specific usage-related CTCs were calculated.

20 A. The class-specific CTC charges (¢/kWh and \$/kW) were calculated as a residual
21 from the target usage rates designed for each rate class. Total target usage rates
22 were designed to enhance stranded cost mitigation as discussed earlier in my

1 testimony. These target rate levels (net of CGCs) are reduced by the usage rates
 2 for distribution and transmission service. The remainder is the variable or usage-
 3 related CTC charge.

4 Q. Can you illustrate this approach with some examples for the various rate classes?

5 A. Yes. For rate class RS, the class-specific CTC is computed by subtracting the
 6 unbundled transmission and distribution rates from the target delivery rate of 3.97
 7 ¢/kWh (net of the CGC). In this case the result is a class-specific CTC rate of
 8 0.72 ¢/kWh as derived below:

Target rate (net of CGC)	Distribution rate	Transmission rate	Variable CTC rate⁽¹⁾
3.97 ¢/kWh	(2.81 ¢/kWh)	(0.45 ¢/kWh)	0.72 ¢/kWh

⁽¹⁾ Numbers may not add due to rounding.

9 Q. How were these rates developed for rate class RH?

10 A. In the same fashion, by subtracting the unbundled transmission and distribution
 11 rates from the target rate components. Set forth below are the variable CTC rates
 12 for rate class RH:

Block	Target rate (net of CGC)	Distribution	Transmission	Variable CTC rate⁽¹⁾
1 st 500 kWh	3.99 ¢/kWh	(3.16 ¢/kWh)	(0.52 ¢/kWh)	0.30 ¢/kWh
> 500 kWh (Winter)	2.65 ¢/kWh	(2.10 ¢/kWh)	(0.35 ¢/kWh)	0.20 ¢/kWh

⁽¹⁾ Numbers may not add due to rounding.

13 Q. Can you show the calculations for a rate class with demand meters, such as GL?

14 A. These are provided in the table below:

Block	Target rate (net of CGC)	Distribution	Transmission	Variable CTC rate ⁽¹⁾
1 st 300 kW	\$5,527/mo.	(\$1,546.19/mo.)	(\$429.56/mo.)	\$3,551.25
> 300 kW	\$6.99/kW	(\$1.96/kW)	(0.54/kW)	\$4.49/kW
kWh	1.95 ¢/kWh	(0.54 ¢/kWh)	(0.15 ¢/kWh)	1.25 ¢/kWh

⁽¹⁾ Numbers may not add due to rounding.

1 Q. Were the class-specific CTC rates developed similarly for the remaining rate
2 classes?

3 A. Yes, Exhibit JAL-9 shows the variable class-specific CTC rates and the data
4 supporting these calculations.

5 **b) Customer-Specific Competitive Transition Charges**

6 Q. Please describe how the customer-specific CTC is calculated?

7 A. The customer-specific charge is also computed as a residual component. It is
8 designed to insure that customers who remain as full requirements customers pay
9 no more than current rates assuming 1996 test year sales.¹⁰ The customer-specific
10 CTC is determined by subtracting the variable CTC charges at customer-specific
11 baseline usage levels from the total CTC-related revenue requirement discussed
12 above.

13 Q. Please derive the customer-specific CTC charge for a typical RS customer?

14 A. I will do so for a customer with a monthly baseline consumption of 500 kWh. At
15 this consumption level the customer would pay the following monthly charges:

¹⁰ Customers that can shop for electricity from alternative suppliers may pay less in total if they can purchase electricity for less than the CGC.

1	Customer charge	\$6.38/mo.
2	Energy charge (500kWh @ 11.66 ¢/kWh)	\$58.30
3	ECR credit (500kWh @ .1831 ¢/kWh)	<u>(\$0.92)</u>
4	Total Bundled bill	\$63.76

5 The next step is to reduce the baseline bill by the sum of the transmission,
6 distribution, and class-specific variable CTC delivery charges derived earlier:

7	Total bundled bill	\$63.76
8	less: distribution customer charge	(\$6.38)
9	less: distribution charge @ 2.81 ¢/kWh	(\$14.03)
10	less: transmission charge @ 0.45 ¢/kWh	(\$2.25)
11	Less variable CTC @ 0.72 ¢/kWh	<u>(\$ 3.58)</u>
12	Generation-related cost	\$37.52

13 The final step is to compute the fixed CTC component by subtracting the
14 CGC from the generation-related cost:

15	Generation-related costs	\$37.52
16	CGC @ 1.856 ¢/kWh	<u>(\$9.28)</u>
17	Customer-specific CTC	\$28.24

18 In this example, I have used a CGC of 1.856 ¢/kWh based on the most recent
19 RFP. The actual CGC for rates effective January 1, 1999, will be determined
20 through a competitive solicitation prior to the start of the phase-in period.

21 Q. Did you compute the customer-specific CTC for customers in the other rate
22 classes in the same way?

1 A Yes. Exhibit JAL-4 introduced earlier in my testimony provides sample
2 calculations of customer-specific CTCs for typical customers in all other rate
3 classes.

4 **c) Customer Baselines**

5 Q. You mention customer baseline information in your rate design proposal. Please
6 explain how you propose to establish these baselines.

7 A. Historical monthly billing records for 1996 will be used to establish baselines for
8 each existing premise in Duquesne's service territory. This is consistent with the
9 cost of service study and the rate design. For those premises where monthly data
10 is unavailable, missing data for those particular month(s) will be filled in with
11 premise-specific data using billing information from 1995. If this process fails to
12 produce a complete year of billing information, Duquesne will then estimate
13 missing monthly data for each premise by using the ratio of premise-specific to
14 class average data for the months data are available.

15 Q. Will these baselines be re-computed over the transition period?

16 A. No. The baselines established for existing premises based on 1996 data will
17 remain fixed throughout the transition period. Fixing the baseline levels has
18 several advantages for customers. First, the benefits of lower charges for
19 incremental consumption will not be partially offset by increased customer-
20 specific CTCs that would otherwise result by re-computing baselines at higher
21 future sales levels. This will prevent dissuading customers from making socially
22 beneficial consumption decisions now. More importantly, all customers will be

1 treated on a comparable basis thereby minimizing concerns that some individual
2 or customer group is being treated unfairly. Use of historical customer baselines
3 will prevent gaming and insure that all customers pay their fair share of stranded
4 costs consistent with the intent of the Act.

5 Q. How will baselines be estimated for new premises that connect to the Duquesne
6 system during the transition period?

7 A. Duquesne will estimate customer baselines using the best customer usage
8 information available. Currently, based on existing procedures, Duquesne's New
9 Business Managers and Account Representatives (reporting to Mr. Frank
10 Hoffmann, General Manager of Marketing) receive information provided by each
11 new customer regarding installation of new electrical equipment from which
12 expected billed demand is computed. Electrical energy consumption is then
13 computed based upon the estimated billed demand times the expected number of
14 hours the customer operates in the month. With this information customer-
15 specific CTCs can be established for each new premise. For existing Duquesne
16 customers that move into another premise during the transition period, the
17 Company will use the baseline established for that residence. For residential
18 customers moving into a new premise, the Company will use similar premises in
19 similar neighborhoods to determine a baseline proxy for the new premise. Once
20 12 months of billing history has been recorded, Duquesne will compare estimated
21 and actual consumption and make adjustments to the baseline levels if a
22 significant difference exists (either upward or downward).

1 **D. Customer Choice Options Under Duquesne's Plan**

2 Q. What rate options will customers have under Duquesne's restructured tariff
3 offerings?

4 A. A customer who is eligible to exercise choice of supplier will have the option of
5 contracting for electricity directly with a PaPUC-approved electricity supplier or
6 remaining as a Duquesne full requirements customer on an unbundled basis.
7 Customers that choose an alternative supplier will be responsible for paying
8 Duquesne delivery charges for distribution, transmission and CTC.¹¹ A customer
9 who initially decides to take power service from an alternative supplier will be
10 able to return to Duquesne's full requirements service (under the rate cap
11 provisions of the Act) anytime after a 30 day notification period. However,
12 customers who return to Duquesne will be restricted from switching again to
13 another supplier within a 12 month period from the date of their return. This
14 restriction will also apply to new customers to insure that returning and new
15 customers are treated similarly, as the Act requires. This restriction is necessary
16 to protect the Company against opportunities for "gaming". In the absence of this
17 safeguard, gaming opportunities would be present for marketers to aggressively
18 encourage customers to take power from them during low cost periods and then
19 switch back to Duquesne during high cost periods. Since Duquesne's rates would
20 be subject to the rate cap provisions of the Act, the Company would potentially be

¹¹ Duquesne will also collect electricity charges for the supplier unless the customer elects a separate bill.

1 unable to fully recover the costs incurred to supply service to these customers. In
2 the PECO restructuring case, the OCA objected to the one-year stay-out provision
3 and has suggested allowing utilities to charge returning customers a short-term
4 market price in order to avoid the “gaming” problem. This would be acceptable
5 to Duquesne only if the short-term market price was not subject to the rate cap
6 provisions in the Act. Otherwise, the OCA’s proposal would not solve the
7 problem.

8 Q. What will customers who remain with Duquesne pay?

9 A. These customers would pay the delivery charges discussed above plus the CGC.

10 Q. Please explain the relationship between the annual competitive bid solicitations
11 and the CGCs over time.

12 A. Duquesne will conduct a one year solicitation prior to the beginning of each year
13 during the transition period to determine the competitive market price. The
14 resulting market prices will then be the basis for setting CGCs for each year of the
15 transition period. As such, the CGCs will change during the transition period
16 based on the results from the annual solicitations. In addition, the CTCs will be
17 re-computed each year to insure that Duquesne remains within the confines of the
18 rate cap provisions of the Act. Therefore, if market prices rise over time, the
19 CTCs will fall and vice versa. Finally, the market prices from the RFP will be
20 used to establish Duquesne’s retail generation charges over the transition period.

VI. MARKET PRICES IN DUQUESNE'S MARKET

1 Q. Please turn to the issue of market prices for electricity. What is the scope of your
2 testimony on this subject.

3 A. I discuss two issues relating to the market price of power. First, I discuss the
4 nature of the market in which Duquesne competes and in particular the difference
5 between power markets in ECAR and power markets in PJM. Second, I provide
6 public data on market prices and show that these data are consistent with the
7 market prices revealed in Duquesne's recent RFP.

8 Q. Please turn to the first issue, markets for electricity, and explain why you are
9 discussing this issue.

10 A. I address this issue because of the Commission's preliminary ruling in the pilot
11 program orders. In those orders, the Commission set a single state-wide market
12 price of power. Duquesne is proposing here, however, to calculate CGCs on the
13 basis of market prices relevant to Duquesne, not all the other Pennsylvania
14 utilities.

15 The principal flaw in the Commission's approach in the pilot orders was its
16 recommendation that a single market price of power be used for all Pennsylvania
17 utilities, thereby failing to recognize that Pennsylvania utilities may face differing
18 market conditions. As I show below, the market prices prevailing in western
19 Pennsylvania are materially lower than the market prices in eastern Pennsylvania.
20 The reason is that eastern Pennsylvania (consisting of service territories for

1 Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power & Light, and
2 PECO Energy) is located within PJM, an electrically constrained regional market.

3 Q. Please explain.

4 A. PJM is an electric "island," having only limited transmission import capability to
5 the west (ECAR) and to the north (New York). This is important because, during
6 certain hours of the year, PJM utilities cannot rely on the same low-cost sources
7 of power (principally coal-fired units) available to utilities in ECAR, including
8 Duquesne. Rather, during these hours PJM must operate gas-fired generating
9 units that have a higher marginal running cost. Hence, the market rate for power
10 in PJM will be higher in these hours than it is in ECAR.

11 More specifically, the peak load in PJM is approximately 50,000 MW, but
12 PJM's total transmission import capability is 5,000 MW or less. As a result, PJM,
13 unlike other regions of the country, cannot rely on its transmission ties to other
14 areas to import substantial amounts of energy for economic purposes, or in the
15 case of an emergency such as the unexpected outage of several large generating
16 units. Not only is the ECAR region much larger (85,000 MW), but ECAR has
17 strong transmission ties to neighboring regions. This, when coupled with other
18 factors, such as an excess of generating capacity over the amount needed to
19 reliably supply customers, has resulted in there being very little, if any, value to
20 "capacity" within ECAR today. This conclusion is supported by Mr. Irvin in his
21 testimony.

22 Q. Please turn to the second issue, the presentation of public data on market prices.

1 A. I present this public data because it is useful in confirming the prices produced in
2 Duquesne's recent RFP for the one-year sale of power.¹²

3 The first such public data source I use is the FERC Form No. 714, which
4 provides data on a utility's "system lambda." System lambda refers to the incre-
5 mental cost to a utility of supplying the last megawatt of energy each hour of the
6 year. It thus represents the "marginal" cost of supplying electricity to customers.
7 This marginal cost could represent the cost of producing energy from the utility's
8 own generation or the cost of purchasing power from others. I view this informa-
9 tion as particularly useful in estimating prices in a competitive market because, in
10 a competitive market, prices will be driven close to marginal cost. It is thus likely
11 that, at least in the near term, the market price of power will be close to each
12 utility's control area lambda as reported on the FERC Form No. 714.

13 Q. Please explain what this data shows.

14 A. I will summarize system lambda data both for Duquesne and for PJM as a whole.
15 I provide the latter calculation for the purpose of illustrating the difference in
16 prices (costs) in the two market areas. The reason I have treated PJM as an entity
17 is because PJM operates economically as a single "control area" (which means all
18 generation within the pool is dispatched in economic merit order) and therefore
19 PJM reports a single pool-wide system lambda in its FERC Form 714. I have

¹² As to the eight-year sale of power, however, there is no comparable public data of which I am aware.

1 taken the system lambda for each of the 8760 hours of the year and calculated a
2 numerical average price, which is as follows:

3	<u>Year</u>	<u>Duquesne</u>	<u>PJM</u>
4	1995	\$17.56/MWH	\$20.56/MWH
5	1996	\$17.99/MWH	[N/A]

6
7 This information corresponds, as one would expect, to public data on
8 actual market prices within the respective regions, including the results of
9 Duquesne's recent RFP. This close correlation suggests that short-term power
10 markets are workably competitive such that prices are being driven close to the
11 marginal cost of production, as economic theory would suggest. Indeed, the
12 FERC recently held that system lambda data is a good proxy for market clearing
13 prices. Ohio Edison et al., Docket No. EC97-5-000 (July 16, 1997).

14 Q. What other data sources have you used?

15 A. The other source of data is Power Markets Week, which is published by McGraw-
16 Hill. According to the editors of Power Markets Week, the publication conducts
17 confidential surveys of buyers and sellers of the prices charged in wholesale
18 power transactions in different regions. Using this information, Power Markets
19 Week constructs a weekly weighted average power price index for peak periods
20 and a weekly price range for off peak periods for several regions of the country,
21 including ECAR and PJM. I have included data from the years

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1 1996 and 1997 in Exhibit JAL-13, the results of which are summarized in the following
2 the table:

3 **ELECTRICITY PRICES IN ECAR AND PJM (\$/MWH)**

	ECAR	PJM	Price Difference
Jan-July 1997			
On-Peak	21.17	24.56	16%
Off-Peak	<u>13.60</u>	<u>16.55</u>	<u>17%</u>
Wtd. Average	\$17.47	\$20.36	17%
1996			
On-Peak	22.52	25.29	12%
Off-Peak	<u>14.30</u>	<u>15.46</u>	<u>8%</u>
Wtd. Average	\$18.20	\$20.13	11%

4 As the table indicates, the weighted average market price of power in ECAR was
5 below \$0.02/kWh (\$20/MWH) in both years and for the year 1996 it was approxi-
6 mately \$18/MWH. That data is consistent with the prices resulting from the RFP
7 and the system lambda data. The Power Markets Week data also confirms the
8 proposition that power prices in PJM tend to be materially higher than in ECAR.

VII. OTHER RATES AND RIDERS

9 **A. Treatment of Supplemental and Back-Up Rates for Self-Generators**

10 Q. Does Duquesne plan to eliminate Rider 16 for backup or partial requirements
11 service for customers that have access to self-generation?

12 A. Yes, but only for new customers and existing retail customers that install self-
13 generation in the future.

1 Q. Please explain.

2 A. Existing customers with self-generation will continue to pay the current rates in
3 effect under the current rider provisions and charges. However, consistent with
4 the Act, Duquesne proposes to eliminate Rider 16 for existing retail customers
5 and new customers moving into its service territory that install new generating
6 capacity in the future. These changes will take place upon Commission approval.

7 Q. Describe the requirements of the Act pertaining to customer self-generation.

8 A. Section 2808 (A) of the Act states that:

9 "If a customer installs on-site generation which operates in parallel with
10 other generation on the public utility's system and which significantly reduces the
11 customer's purchases of electricity through the transmission and distribution
12 network, the customer's fully allocated share of transition or stranded costs shall
13 be recovered from the customer through a competitive transition charge."

14 This section of the Act is based on sound public policy principles by
15 effectively preventing such customers from bypassing their fully allocated share
16 of transition costs.

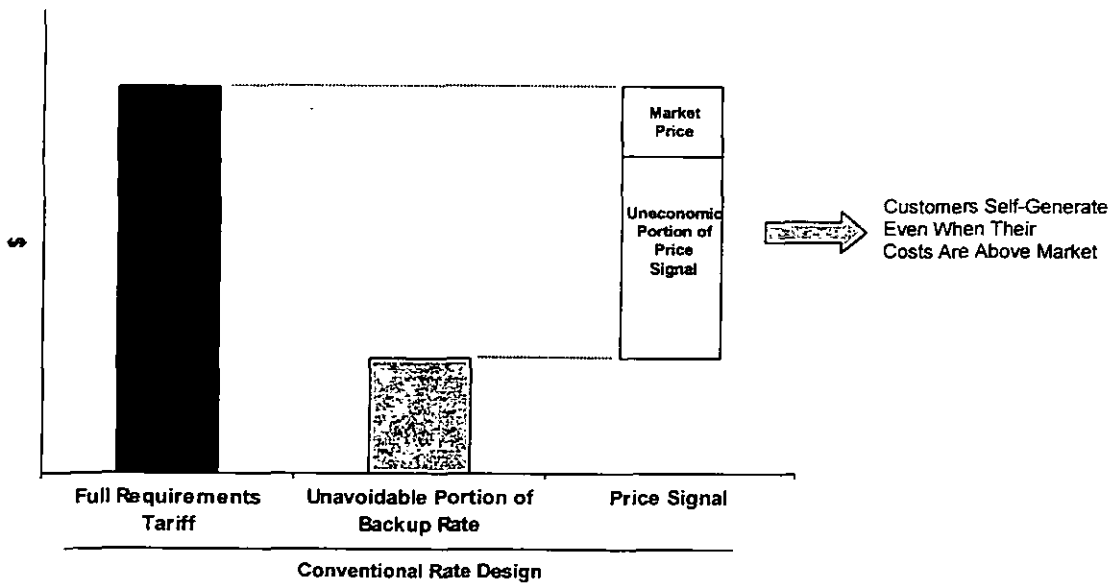
17 Q. If kept in place, would Duquesne's Rider 16 allow customers that install self-
18 generation in the future to bypass paying for their fair share of transition costs?

19 A. Yes. The prospect of uneconomic bypass arises because potential self-generation
20 projects "compete" not against the market price of power but rather against
21 Duquesne's embedded cost tariffs, which are currently much higher than the
22 market price for power. Duquesne's current Rider 16 encourages inefficient by-

1 pass because a customer installing self-generation equipment could avoid paying
2 for a large portion of fixed costs currently recovered through retail tariffs. This
3 sends an uneconomic price signal to potential self-generators as shown below:

4
5 Customers that install self-generation equipment would realize savings equal to

Uneconomic Bypass Of Stranded Costs



6 the difference between the total full requirements rate and the unavoidable charges
7 under Rider 16. This difference is the amount by which their utility bill would go
8 down if they decide to install self-generation equipment. If they can install and
9 operate self-generation equipment at a cost below this bill differential they will
10 have a financial incentive to self-generate. However, the problem with Rider 16
11 is that it may encourage some customers to install self-generation equipment even
12 when the cost of self-generation exceeds the market price of power. This
13 incentive to install self-generation raises the potential for inefficient entry into the

1 generation market and could frustrate Company efforts to recover its stranded
2 costs over the transition period.

3 Q. What are the implications of this?

4 A. Uneconomic bypass of Duquesne's electric system will result in inefficient use of
5 society's resources, and unnecessarily shift costs from the customer who installs
6 self-generation to remaining customers and/or Duquesne shareholders.

7 Q. How can this problem be solved?

8 A. The solution is found in the provisions of the Act by allowing utilities to assess a
9 Competitive Transition Charge against such customers. This can be accomplished
10 by redesigning rates for partial requirements service in the same manner
11 Duquesne redesigned rates for its other services.

12 Q. How would charges be calculated for new self-generators?

13 A. Duquesne would use the same applicable tariff as the customer would have faced
14 prior to self-generation. Duquesne would calculate baseline revenues for existing
15 and new retail customers according to the appropriate full requirements tariff.
16 From this amount, we would subtract transmission and distribution charges, and a
17 competitive generation credit based on the results from the most recent RFP, in
18 order to determine a customer-specific CTC. The customer would be responsible
19 for the customer-specific CTC whether or not he chooses to install self-generation
20 in the future. When the self-generation customer purchases power from
21 Duquesne, he will pay the market price of power and any related transmission and
22 distribution delivery charges.

- 1 Q. Will the use of these tariffs allow Duquesne to totally eliminate uneconomic price
2 signals to install self-generation?
- 3 A. No. To do this, Duquesne would have to increase the fixed charges contained in
4 the retail rates. As it is, customers considering self-generation will be able to
5 avoid paying Duquesne's CGC, variable CTC, usage-related distribution and
6 transmission charges. The sum of these charges will clearly exceed market levels.
- 7 Q. Will Duquesne's proposal prevent customers from installing self-generation when
8 it is economic?
- 9 A. No. Uneconomic entry and the creation of stranded costs are discouraged, but
10 economic entry is not. Customers will continue to have the correct incentive to
11 install self-generation whenever the costs of self-generation are less than market
12 prices. Moreover, this is consistent with Duquesne's resource planning criteria in
13 a competitive market. Duquesne would only consider development of new
14 generation resources if all the costs of such a facility could be recovered in the
15 competitive market. This is the same standard that should be applied to customer-
16 developed generation going forward. In addition, Duquesne's proposal to lower
17 usage charges (energy and/or demand related) closer to market levels will
18 encourage more efficient customer dispatch of self-generation units. Thus,
19 Duquesne's revised tariff will not only improve efficiency with respect to
20 customer investment decisions, but also improve customer operating decisions.
- 21 Q. Would the revised rider violate the total rate cap specified in the Act?

1 A. No. The sum of all the charges would never exceed charges under the current
2 applicable full requirements tariff.

3 Q. Can self-generation customers purchase back-up service from alternative
4 suppliers?

5 A. Yes. The new rider is designed to be competitively neutral. Customers could
6 choose to purchase backup supplies from either Duquesne or a competitive
7 supplier.

8 Q. Why does Duquesne propose to "grandfather" existing customers with self-
9 generation on Rider 16?

10 A. These customers chose to install self-generation based on the economics at the
11 time of their decisions. And while some of these decisions may have been
12 uneconomic measured by competitive power market standards, Duquesne
13 recognizes that it would be unfair to retroactively change the rules of the game.
14 Duquesne's intent is to provide proper pricing signals for future decision-making
15 and not to penalize customers for decisions made under the old regulatory
16 environment.

17 **B. Treatment of Service Rates and Other Riders**

18 Q. Are there some rates that you did not unbundle?

19 A. Yes, there are some rates which provide a service in addition to providing electric
20 service.

21 Rate SM provides a street lighting service to municipalities that do not
22 want to own and operate their own street lighting equipment. The major cost

1 components of this rate are related to the cost of providing the lighting equipment
2 and its maintenance. Therefore, Duquesne will continue to provide this service
3 under a bundled rate.

4 Rate SH provides a lighting service for state highways that have turned
5 ownership of the lighting system to Duquesne, where Duquesne is responsible for
6 future replacement and maintenance of the system. Similar to Rate SM, the major
7 cost components of this rate are related to the cost of replacing and maintaining
8 the lighting equipment. Therefore, Duquesne will continue to provide this service
9 under a bundled rate.

10 Rate SE provides street lighting energy to municipalities that have at least
11 15,000 street lamp installations, where the municipality owns and operates its own
12 street lamp installations. Currently the only customer is the City of Pittsburgh.
13 The kWh energy charge in this rate will be unbundled into its transmission,
14 distribution, generation CGC and CTC components. This will allow the city to
15 shop for its electricity supply like any other retail choice customer. Rate SE also
16 includes pricing for Special Facilities such as conduit, cable, ballasts, etc., that
17 were designed to directly recover their costs. Therefore, charges for Special
18 Facilities will remain bundled.

19 Rate PAL provides both a private area lighting service to residential,
20 commercial and industrial customers who do not want to own, install, and operate
21 their own lighting equipment, and unmetered energy to serve customers who want
22 to own, install, and maintain their own equipment. Duquesne will continue to

1 provide the service for Company-owned and maintained equipment at the current
2 bundled prices since the major cost components of this service are related to the cost
3 of providing the lighting equipment and its maintenance, similar to Rate SM. For
4 customer-owned and maintained equipment the kWh energy charges of the rate will
5 be unbundled into their transmission, distribution, generation CGC and CTC
6 components, similar to Rate SE.

7 Q. Does the unbundling of Duquesne's tariff impact any of the riders?

8 A. Yes, some riders will be affected. Duquesne's current tariff has 20 riders. Ten of
9 the existing riders are related to the timing of payments and billing options for
10 customer convenience and are not related to rate unbundling. These riders will
11 remain largely unmodified except for references to renamed unbundled rates and the
12 applicability of the rider to Duquesne delivery charges. The riders (as they are
13 currently numbered) which fall into this category are as follows:

14 Rider No. 1 - Direct Current Service

15 Rider No. 2 - Untransformed Service

16 Rider No. 3 - School and Governmental Service Discount Period

17 Rider No. 4 - HUD Financed Multi-Family Housing

18 Rider No. 6 - Temporary Service

19 Rider No. 11 - Street Railway Service

20 Rider No. 10 - State Tax Adjustment

21 Rider No. 12 - Billing Option for Volunteer Fire Companies and Non-Profit Senior

22 Citizen Centers

1 Rider No. 17 - Emergency Energy Conservation

2 Rider No. 18 - Rate for Purchase of Electric Energy from Customer-Owned
3 Renewable Resources Generating Facilities.

4 Q. Please describe the modifications that were made to the remaining riders.

5 A. Of the remaining ten riders, some were revised to reflect supplier choice and others
6 were deleted.

7 Rider No. 7, Interruptible Service will be revised to apply to existing full
8 requirements customers only. It is not meaningful for Duquesne to provide a
9 generation related discount for customers who purchase power supplied by others.
10 The customers' discounts from the current level of interruptible service will be
11 maintained if they take electricity from Duquesne. Customers that choose
12 alternative supplies can negotiate market based-discounts for interruptible service.

13 Rider No. 13, General Service Separately Metered Electric Space Heating
14 Service, Rider No. 14, Residential Service Separately Metered Electric Space and
15 Water Heating, and Rider 19 Off-Peak Water Heating Service were eliminated.
16 These riders provide pricing for incremental energy used for specific space and
17 water heating services to customers already taking the bulk of their service at full
18 service rates. Under Duquesne's proposed rate redesign, customers will be able to
19 purchase incremental energy at market-based rates eliminating the need for these
20 riders. Existing customers taking service will continue to receive the benefits of the
21 riders at their baseline energy consumption through the customer-specific CTC
22 calculation.

1 Rider 15, Energy Cost Rate, is affected only by variable generation costs
2 and was rolled into rates at a cost justified level, as described by Mr. Clayton. The
3 effect of the Energy Cost Rate roll-in will be captured in the fixed CTC calculations.

4 Q. Do you still plan to have economic development riders as part of the tariff?

5 A. Yes. As explained in Mr. Hoffman's testimony, Duquesne will provide rates to
6 encourage economic development at new service locations. Economic
7 development at existing locations will be provided through Duquesne's
8 redesigned and unbundled tariffs.

9 Q. Would you please explain this in more detail.

10 A. Certainly. Rider No. 8, Industrial Economic Development Rider for Customers at
11 Existing Service Locations will be phased-out as existing contracts expire. The
12 rider will be unavailable to new customers after December 31, 1998. This should
13 have little customer impact because incremental usage above the baseline will be
14 priced at lower usage charges under Duquesne's unbundled rate design.
15 Customers who are taking service with the Rider No. 8 discount as of December
16 31, 1998 will continue to receive their discount according to the contract schedule
17 through the remainder of their 5 year contract. The discounts will be reflected in
18 calculating the customer's fixed CTC.

19 Rider No. 9, Industrial Economic Development Rider for Customers at New
20 Service Locations, and Rider No. 20, Small Business Development Rider applied to
21 new locations, remain unchanged except for modifications in the tariff language to
22 reflect the fact that the discount will be recognized in calculating the customer-

1 specific CTC. Industrial customers at new service locations will still be eligible for
2 the applicable economic development discounts regardless of the supplier.
3 Duquesne still believes that economic development is very important for its
4 customers and is consistent with the Act, the PaPUC guidelines, Governor Ridge's
5 expressed interest in economic development, and the PaPUC Working Group's
6 current approach to the transition into retail access.

7 Q. Please explain the effect of the proposed modifications to existing customers on
8 Rider No. 5 Time of Day Discounts.

9 A. Rider No. 5 was revised to apply to existing customers as of December 31, 1998
10 who have changed their operations to benefit from Duquesne's on-peak and off-
11 peak period rate. Retaining the rider will ensure that these customers will not see
12 an increase in their bill. Rider No. 5 will not be available for new customers
13 because it was designed to encourage off-peak usage thereby relieving system
14 generation load (and costs) during peak periods. It is not meaningful for
15 Duquesne to provide a generation discount for customers who purchase power
16 supplied by others. For customers desiring to revise their operating schedules
17 after December 31, 1998, any benefits derived from off-peak operation will be
18 realized between the customer and the supplier.

19 Q. Will customers taking service with Rider 5 on December 31, 1998 see an increase
20 on January 1, 1999?

21 A. No. Their billing demand will continue to be established through the Rider No. 5
22 criteria, that is, the greater of on-peak demand or one-third off-peak demand.

1 Existing Rider No. 5 customers, whether they choose a new supplier or receive
2 energy from the Company, will receive the same time of day discount at their
3 1996 usage level through the CTC calculation.

4 Q. Will this customer receive any additional off-peak discounts on load levels which
5 exceed its baseline usage?

6 A. No. All existing discounts will be retained at the baseline usage level through the
7 CTC calculation. All incremental load will be delivered at the appropriate
8 delivery rate at the chosen supplier prices. The customer could benefit from
9 shifting load to off-peak periods if its supplier provides time of day discounts.

10 Q. What modifications were made to accommodate the back-up power customers
11 currently billed under rider 16?

12 A. Rider 16 was renumbered as Rider 10, Service to Non-Utility Generating
13 Facilities, and will remain largely unchanged for existing customers. The sole
14 change for existing customers will be a change from a bundled to an unbundled
15 bill for supplementary power. All other charges, terms and conditions for Firm
16 Back-up Power, Interruptible Back-up Power and Maintenance Power will be
17 unchanged and frozen for existing customers. The changes for new customers and
18 existing customers considering self-generation were discussed earlier in my
19 testimony.

20 **C. Appendix A Responses**

21 Q. What data items identified in Appendix A to the Commission's order are you
22 sponsoring?

1 A. I am sponsoring the responses to the following data requests:

2 • A1

3 • I1-I18

4 • J1-J3

5 • K1-K2

6 • L12-13, L15

7 • M2

8 Q. Does this conclude your testimony?

9 A. Yes, it does.

List of Exhibits for James A. Lahtinen

- Exhibit JAL-1 Allocated Cost of Service
 - Schedule A Cost of Service Study Results
 - Schedule B Cost of Service Study Results (By FERC Account)
 - Schedule C Cost of Service Study Results (Basis for Rates)
 - Schedule D Cost Allocation Table
 - Schedule E Derivation of Production Based Ancillary Services
- Exhibit JAL-2 FERC Testimony of Peter A. Wybierala
- Exhibit JAL-3 Comparison of Cost Allocations to Company Revenues
- Exhibit JAL-4 Comparison of Bundled Versus Unbundled Charges for Sample Customers
- Exhibit JAL-5 Potential Stranded Cost Mitigation Resulting from Rate Redesign
- Exhibit JAL-6 Rate Reduction on Incremental Usage – Comparison of Bundled and Unbundled Usage Rates
- Exhibit JAL-7 Mitigation Sensitivity Analysis: Changes in Energy and Demand Price Elasticities
- Exhibit JAL-8 Mitigation Sensitivity Analysis: Changes in Percentage Reduction in Most Energy and Demand Charges
- Exhibit JAL-9 Comparison of Current Bundled and Proposed Unbundled Usage Rates
- Exhibit JAL-10 Retail Versus Wholesale prices in Massachusetts
- Exhibit JAL-11 Sample Customer Generation Charges/Credits Based on Recent RFP
- Exhibit JAL-12 Sample Tariff Sheets by Rate Schedule
- Exhibit JAL-13 Market Prices in ECAR and PJM

Exhibit JAL-1

Schedule A

Schedule B

Schedule C

Schedule D

Schedule E

Schedule A

Cost of Service Study Results

(Pages 1-10)

**COST OF SERVICE STUDY
(1996)**

	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BE	BN	BRDM	BMH	QL	QLH	L	HVPS	AL	RE	SM	SH	TRAFFIC SIGNALS
Electric Plant In Service																	
(1) Production Plant	12,366,398,721	12,309,085	12,304,089,836	10,371,583	10,668,582,339	102,849,039	1595,660,714	109,243,606	1464,055,166	180,889,437	1195,238,257	1185,071,708	13,259	15,987,805	10,580,081	1175,045	11,380,915
(2) Transmission Plant	312,186,756	294,078	311,892,678	847,900	73,091,533	6,359,087	81,814,322	7,900,816	64,336,835	11,324,125	40,848,332	24,789,158	90	173,089	180,218	5,081	212,303
(3) Distribution Plant	1,237,225,730	359,992	1,232,865,738	1,411,052	1,25,840,589	12,042,559	312,302,816	32,818,325	175,890,817	24,820,438	85,275,511	11,275,923	1,348	18,384,996	11,298,085	289,185	904,818
Total	13,915,811,207	12,963,155	13,908,848,252	113,630,535	112,717,520,471	113,150,685	1980,777,851	115,063,757	1703,487,838	119,034,060	121,382,100	1221,136,789	15,038	16,465,990	118,058,384	1489,271	12,499,834
General & Intangible Plant																	
Production Plant	174,057,999	169,842	173,888,156	815,783	49,176,879	8,093,875	4,810,205	5,093,141	34,133,097	5,949,739	14,360,547	13,612,757	240	440,431	484,035	12,875	101,572
Transmission Plant	6,665,279	6,467	6,858,812	10,846	1,607,351	139,842	1,789,174	173,746	1,414,823	249,028	898,293	545,137	2	3,807	4,183	111	4,889
Distribution Plant	108,421,204	31,848	108,389,555	382,805	11,834,883	3,636,245	27,544,578	3,333,745	15,383,410	2,357,266	7,497,148	981,343	154	1,616,349	3,630,792	25,422	79,707
TOTAL GENERAL & INTANGIBLE PLANT	289,144,482	207,957	289,136,524	1,022,215	92,619,119	9,929,962	73,156,954	8,600,633	50,941,336	8,556,732	22,755,988	15,149,237	395	2,080,587	4,119,010	38,409	185,947
Electric Plant In Service																	
Total Production Plant	2,540,456,720	2,478,829	2,537,977,792	8,987,346	717,759,219	88,942,314	838,473,918	74,336,747	498,100,283	88,839,178	709,598,004	198,684,485	3,499	6,428,298	7,064,716	187,920	1,402,407
Total Transmission Plant	319,052,035	300,545	318,751,481	888,548	74,698,884	6,498,929	83,613,495	8,074,583	65,751,458	11,573,153	41,748,825	25,334,299	92	176,808	194,401	5,172	214,971
Total Distribution Plant	1,341,646,934	391,641	1,341,255,293	4,298,858	517,681,486	45,738,684	348,847,492	41,253,089	190,484,233	29,178,404	92,772,657	12,287,286	1,901	20,001,345	44,928,852	314,587	988,322
TOTAL ELECTRIC PLANT IN SERVICE (1+2+3+4)	4,201,155,690	3,171,113	4,197,984,576	14,174,752	1,309,139,589	141,180,648	1,063,934,906	123,604,389	754,423,974	127,590,735	824,118,088	426,788,025	5,492	6,605,441	7,263,927	198,619	2,605,700
Accumulated Depreciation																	
(1) Production Plant	(11,081,527,982)	(11,055,408)	(11,080,471,976)	(13,823,817)	(1,305,445,345)	(137,832,824)	(1,272,115,603)	(131,638,732)	(1,212,201,568)	(176,975,615)	(1,018,352,159)	(184,629,410)	(1,489)	(2,736,140)	(1,007,034)	(179,987)	(1,532,454)
(2) Transmission Plant	(117,680,602)	(110,819)	(117,579,783)	(310,941)	(27,483,701)	(2,391,998)	(39,770,993)	(2,971,927)	(24,700,508)	(4,759,619)	(15,879,208)	(9,374,551)	(34)	(65,112)	(71,551)	(1,304)	(19,895)
(3) Distribution Plant	(388,407,588)	(105,215)	(388,302,373)	(1,364,362)	(151,240,494)	(12,893,823)	(96,134,098)	(11,412,088)	(58,804,899)	(17,850,388)	(23,382,899)	(3,267,540)	(53)	(8,111,908)	(10,583,245)	(92,481)	(292,652)
Total	(1,587,616,172)	(1,271,232)	(1,581,354,132)	(15,499,120)	(1,684,169,540)	(143,118,645)	(1,398,020,694)	(146,022,727)	(1,295,706,975)	(199,685,622)	(1,057,534,266)	(207,371,501)	(2,576)	(29,912,360)	(11,661,830)	(181,772)	(1,744,941)
General & Intangible Plant																	
Production Plant	(65,957,768)	(64,355)	(65,888,413)	(232,320)	(18,633,739)	(2,369,046)	(14,601,375)	(1,929,855)	(12,933,460)	(2,254,431)	(5,441,392)	(5,158,045)	(81)	(168,885)	(183,467)	(4,079)	(38,487)
Transmission Plant	(2,801,241)	(2,450)	(2,598,690)	(7,865)	(609,048)	(52,980)	(681,729)	(65,835)	(538,094)	(94,360)	(340,375)	(206,559)	(1)	(1,442)	(1,505)	(42)	(1,789)
Distribution Plant	(11,882,180)	(31,992)	(11,870,188)	(148,944)	(15,851,788)	(1,400,554)	(10,438,302)	(1,283,198)	(5,832,759)	(892,463)	(2,880,763)	(375,632)	(58)	(112,455)	(1,379,753)	(8,633)	(30,202)
TOTAL GENERAL & INTANGIBLE PLANT	(79,641,189)	(98,797)	(79,557,291)	(390,129)	(25,094,575)	(2,822,670)	(17,121,497)	(2,078,888)	(19,304,313)	(3,247,250)	(8,662,530)	(5,740,237)	(139)	(182,782)	(1,964,725)	(13,761)	(40,478)

POOR ORIGINAL

COST OF SERVICE STUDY
(1996)

	Total Index	FERC JURIS.	PA PUC JURIS.	BA	BS	RH	DAIOM	GMH	DL	DLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
Accumulated Depreciation																	
Total Production Plant	(1,147,480,150)	(1,119,781)	(1,146,300,389)	(4,050,937)	(324,079,084)	(40,141,870)	(280,716,978)	(33,566,587)	(225,135,020)	(39,230,046)	(94,793,551)	(89,787,455)	(1,579)	(2,903,033)	(3,190,441)	(84,805)	(870,941)
Total Transmission Plant	(120,291,943)	(113,069)	(120,178,874)	(326,006)	(28,102,747)	(2,444,887)	(31,452,722)	(3,037,781)	(24,738,602)	(4,353,979)	(15,369,861)	(9,531,110)	(35)	(68,554)	(73,136)	(1,940)	(81,828)
Total Distribution Plant	(427,490,128)	(117,207)	(427,372,921)	(1,511,411)	(187,150,802)	(14,294,375)	(106,571,085)	(12,875,268)	(58,717,058)	(8,743,828)	(20,836,462)	(3,743,172)	(592)	(8,754,443)	(19,958,997)	(102,114)	(312,854)
TOTAL ACCUMULATED DEPRECIATION (1+2+3+4+5+6+7+8+9+10+11+12+13+14+15+16+17+18)	(1,695,262,221)	(1,350,037)	(1,693,812,184)	(59,894,355)	(539,332,492)	(56,881,232)	(442,674,785)	(48,281,615)	(300,589,281)	(52,327,854)	(137,599,674)	(103,061,737)	(42,207)	(111,724,031)	(123,222,574)	(188,925)	(1,085,423)
Net Allocated Plant																	
(1) Production Plant	\$1,284,871,339	\$1,253,478	\$1,283,017,660	\$4,547,967	\$383,136,995	\$45,016,215	\$323,545,111	\$37,604,874	\$251,853,626	\$43,913,822	\$105,880,898	\$100,442,287	\$1,771	\$3,251,717	\$3,573,647	\$85,058	\$748,461
(2) Transmission Plant	194,496,154	183,459	194,312,695	528,959	45,587,832	3,967,069	51,043,028	4,928,889	40,130,127	7,094,598	25,219,045	15,486,607	50	107,887	118,887	3,157	132,444
(3) Distribution Plant	848,817,282	254,772	848,582,985	3,044,585	324,547,703	28,148,137	217,168,818	28,507,287	124,205,818	18,870,023	81,279,812	7,808,383	1,214	10,243,008	22,714,820	194,684	823,983
Total	2,928,105,255	1,691,915	2,924,493,340	8,123,511	733,282,530	78,132,041	591,757,258	69,041,030	416,195,871	69,948,400	192,384,958	123,815,288	3,041	13,602,712	26,407,134	294,899	1,504,888
General & Intangible Plant																	
Production Plant	108,105,230	105,487	107,999,743	382,443	30,543,140	3,704,828	27,211,830	3,183,288	21,199,837	3,695,308	8,919,155	8,454,712	149	273,540	300,828	1,997	83,085
Transmission Plant	4,283,939	4,017	4,259,922	11,581	998,306	86,854	1,117,444	107,917	878,779	154,868	557,818	308,578	1	2,364	2,598	69	2,900
Distribution Plant	87,339,044	19,852	87,319,381	240,861	25,883,122	2,295,831	17,107,588	2,820,542	9,569,857	1,484,503	4,658,383	815,710	95	1,003,884	2,255,829	15,290	49,505
TOTAL GENERAL & INTANGIBLE PLANT	179,728,213	129,356	179,579,053	634,885	57,524,568	6,297,513	45,436,862	5,341,745	31,639,022	5,314,479	14,133,457	9,409,000	248	1,279,805	2,559,285	23,855	115,489
Net Allocated Plant																	
Production Plant	1,392,976,589	1,359,166	1,391,017,403	4,930,409	393,660,135	48,801,044	350,756,941	40,768,180	273,053,263	47,609,130	114,805,253	109,497,009	1,920	3,525,263	3,874,275	103,055	811,546
Transmission Plant	198,780,093	187,476	198,572,617	540,539	46,586,138	4,053,943	52,160,773	5,036,801	41,014,856	7,219,174	25,776,964	15,803,185	58	110,351	121,265	3,226	135,344
Distribution Plant	914,159,088	274,434	913,862,372	3,297,438	350,539,828	31,444,479	234,278,407	29,577,814	133,786,575	20,334,575	85,936,195	8,524,094	1,309	11,246,802	24,969,860	212,473	879,488
TOTAL NET ALLOCATED PLANT (1+2+3+4)	2,505,915,770	1,321,076	2,504,452,392	8,768,386	790,786,099	84,299,466	637,194,121	74,302,774	447,834,694	75,262,879	206,516,413	133,224,208	3,277	14,882,517	29,854,399	318,754	1,826,378
Additions & Deductions To Net Plant																	
Additions																	
Land Plant Held for Future Use (17+18)																	
Production Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

POOR ORIGINAL

COST OF SERVICE STUDY
(1996)

	Total DIRTY	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	OSMM	OMH	OL	GLH	L	MYPS	AL	BE	SM	SH	TRAFFIC SIGNALS
CWIP - Construction Work in Progress (P210.1)																	
Production Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deductions																	
Accum. Deferred Income Taxes (P270.277)																	
Production Plant	(255,524,503)	(249,336)	(255,275,167)	(902,906)	(72,193,738)	(8,946,066)	(64,319,638)	(7,476,947)	(50,108,830)	(8,734,466)	(21,081,890)	(19,984,103)	(352)	(648,572)	(710,584)	(18,501)	(149,112)
Transmission Plant	(23,699,224)	(2,324)	(23,676,900)	(64,367)	(5,548,642)	(487,741)	(6,210,821)	(599,779)	(4,884,028)	(859,655)	(3,100,944)	(1,881,895)	(7)	(13,141)	(14,440)	(384)	(16,117)
Distribution Plant	(168,945,782)	(31,802)	(168,913,980)	(389,682)	(62,632,202)	(3,214,128)	(22,627,862)	(2,149,875)	(15,487,898)	(2,388,325)	(2,533,420)	(996,138)	(154)	(1,624,170)	(2,048,358)	(25,545)	(80,052)
TOTAL ACCUM. DEFERRED INCOME TAXES	(388,169,514)	(303,462)	(387,866,051)	(1,358,015)	(119,779,682)	(13,142,937)	(88,208,305)	(11,426,601)	(70,480,752)	(11,983,498)	(31,716,255)	(22,882,077)	(513)	(2,283,882)	(4,373,383)	(44,821)	(245,321)

Rate Base Summary																	
	Total DIRTY	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	OSMM	OMH	OL	GLH	L	MYPS	AL	BE	SM	SH	TRAFFIC SIGNALS
Production Plant	1,137,452,066	1,109,831	1,136,342,236	4,026,443	321,488,397	39,854,978	286,437,303	33,291,213	222,944,433	38,874,662	93,723,363	88,912,906	1,569	2,878,691	3,163,691	84,153	682,434
Transmission Plant	175,080,069	165,151	174,895,218	476,172	41,047,496	3,571,202	45,349,953	4,437,022	30,130,830	6,599,519	22,676,020	13,921,351	51	97,211	106,824	2,842	119,227
Distribution Plant	805,211,819	242,631	804,969,188	2,892,785	308,493,524	22,230,300	286,598,560	25,222,328	118,298,629	18,065,201	58,402,225	7,522,055	1,155	9,622,732	21,321,501	186,928	593,278
TOTAL ADJUSTED NET PLANT (Wash. Base)	\$2,117,723,954	\$1,517,613	\$2,116,206,643	\$7,400,300	\$671,027,419	\$71,156,479	\$538,385,816	\$62,956,172	\$372,373,942	\$63,739,382	\$174,802,157	\$110,362,211	\$2,773	\$12,598,635	\$24,592,016	\$273,923	\$1,375,637
Return on Rate Base @ 7.9, 6.1																	
Production Plant	109,309,144	106,655	109,202,489	386,941	30,894,043	3,030,063	27,528,625	3,199,708	21,424,960	3,735,855	9,000,815	8,544,530	151	276,642	304,031	8,087	63,660
Transmission Plant	16,873,349	15,871	16,807,478	45,780	3,944,664	343,102	4,415,790	426,390	3,472,123	611,150	2,179,165	1,337,042	5	9,342	10,706	273	11,458
Distribution Plant	77,388,179	23,317	77,357,162	278,425	29,646,220	2,864,882	19,054,122	2,424,405	11,388,503	1,738,086	5,612,502	723,636	111	924,785	2,038,956	17,984	57,623
TOTAL RETURN ON RATE BASE	\$203,570,672	\$145,643	\$203,367,129	\$711,147	\$64,485,927	\$6,735,048	\$50,998,537	\$6,050,508	\$36,285,606	\$6,084,071	\$18,798,487	\$10,605,109	\$267	\$1,210,729	\$2,353,723	\$26,344	\$132,541

Adjustments To Rate Base For Rate Making

Add: Regulatory Assets	Total DIRTY	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	OSMM	OMH	OL	GLH	L	MYPS	AL	BE	SM	SH	TRAFFIC SIGNALS
Production	35,273,723	444,247	35,629,476	1,610,617	128,629,198	15,939,406	114,599,737	13,371,844	89,280,023	15,562,397	37,582,076	35,686,124	827	1,152,011	1,286,063	33,677	265,676
Transmission	37,670,171	30,775	37,639,396	88,732	7,648,988	665,475	6,561,023	826,816	6,732,793	1,185,063	4,274,755	2,594,172	9	18,115	19,906	530	22,217
Distribution	58,044,591	16,594	58,027,997	203,324	21,933,283	1,937,319	14,441,942	1,742,083	9,070,826	1,238,282	2,930,709	519,795	81	847,442	1,902,603	13,329	41,290

POOR ORIGINAL

COST OF SERVICE STUDY

(1996)

	Total MWh	FERC Juris.	PA PUC Juris.	BA	BS	BH	GRGM	GMH	GL	GLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS	
Phillips	Total	544,788,405	491,010	544,290,809	1,902,673	158,211,870	18,542,801	137,803,017	15,896,522	104,083,493	17,983,727	45,767,540	38,720,050	717	2,017,968	3,189,572	47,505	329,883
Production	78,399,252	78,500	78,322,752	277,352	22,150,264	2,744,605	18,734,358	2,294,054	15,374,239	2,678,883	6,488,282	6,131,482	108	198,378	218,019	5,789	45,750	
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total	78,399,252	78,500	78,322,752	277,352	22,150,264	2,744,605	18,734,358	2,294,054	15,374,239	2,678,883	6,488,282	6,131,482	108	198,378	218,019	5,789	45,750	
Brunel Island	Total	28,758,563	28,082	28,730,501	101,739	8,125,202	1,008,855	7,238,994	841,509	5,638,808	983,040	2,372,707	2,248,155	40	72,770	79,974	2,127	16,782
Production	28,758,563	28,082	28,730,501	101,739	8,125,202	1,008,855	7,238,994	841,509	5,638,808	983,040	2,372,707	2,248,155	40	72,770	79,974	2,127	16,782	
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total	28,758,563	28,082	28,730,501	101,739	8,125,202	1,008,855	7,238,994	841,509	5,638,808	983,040	2,372,707	2,248,155	40	72,770	79,974	2,127	16,782	
Warwick	Total	15,294,914	14,924	15,279,990	54,109	4,321,298	535,484	3,849,978	447,547	2,999,381	522,818	1,261,897	1,198,187	21	38,702	42,533	1,131	8,925
Production	15,294,914	14,924	15,279,990	54,109	4,321,298	535,484	3,849,978	447,547	2,999,381	522,818	1,261,897	1,198,187	21	38,702	42,533	1,131	8,925	
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total	15,294,914	14,924	15,279,990	54,109	4,321,298	535,484	3,849,978	447,547	2,999,381	522,818	1,261,897	1,198,187	21	38,702	42,533	1,131	8,925	
Deferred Taxes	Total	(300,558,487)	(374,289)	(383,184,728)	(1,356,911)	(108,387,383)	(13,428,613)	(98,547,858)	(11,223,372)	(75,216,534)	(13,110,990)	(31,645,250)	(29,997,407)	(528)	(197,545)	(1,088,632)	(28,372)	(273,826)
Production	(37,049,551)	(34,900)	(37,014,651)	(100,871)	(8,874,322)	(754,881)	(9,709,521)	(877,648)	(7,635,312)	(1,343,919)	(4,847,778)	(2,941,918)	(2,941,918)	(11)	(20,543)	(22,575)	(301)	(25,198)
Transmission	(85,372,582)	(19,084)	(85,358,512)	(233,845)	(25,224,288)	(2,224,823)	(18,868,288)	(2,810,218)	(9,282,125)	(1,421,865)	(4,520,752)	(5,277,768)	(5,277,768)	(93)	(874,853)	(2,189,354)	(15,330)	(48,882)
Distribution	(405,985,645)	(428,254)	(405,557,391)	(1,891,303)	(142,287,983)	(18,412,117)	(122,868,688)	(14,171,258)	(92,134,021)	(15,876,755)	(41,013,787)	(33,537,099)	(33,537,099)	(602)	(1,985,741)	(3,270,581)	(44,302)	(297,085)
Working Capital	Total	83,590,000	82,050	83,527,950	274,862	17,886,182	2,228,324	18,006,828	1,860,718	12,470,117	2,173,888	5,248,453	4,973,257	88	160,908	176,836	4,704	37,108
Production	1,240,000	1,188	1,238,832	3,388	280,318	25,258	324,965	31,382	255,544	44,979	182,249	98,482	0	888	756	20	843	
Transmission	5,110,000	1,482	5,108,538	18,278	1,921,720	174,208	1,200,203	157,123	725,502	111,133	353,338	88,723	7	78,180	121,123	1,398	3,252	
Distribution	89,940,000	84,710	89,879,290	248,607	20,279,221	2,425,790	17,829,797	2,049,223	13,451,188	2,329,778	5,782,050	5,116,442	95	737,774	348,715	5,922	41,708	
Total Net Adjustment to Rate Base	751,195,569	747,559	750,948,010	891,097	70,789,959	8,043,618	63,189,481	7,357,590	-9,413,847	8,672,492	20,818,690	19,876,197	349	599,457	600,753	18,213	145,784	
Rate Base Adjusted For Ratemaking	2,368,919,523	1,765,172	2,367,154,351	8,291,477	741,790,375	88,000,897	602,175,298	70,313,771	-26,707,789	71,921,874	195,428,848	130,240,408	3,173	13,198,087	25,192,768	292,136	1,520,801	
Adjustments To Rate Base For Ratemaking Summary	Production Plant	757,757,955	751,515	757,508,440	911,098	77,074,759	9,874,261	84,081,033	7,542,300	50,548,814	8,810,813	21,266,180	20,156,777	355	657,273	718,795	19,087	150,415
Transmission Plant	(1,139,380)	(2,957)	(1,136,423)	(8,527)	(735,015)	(63,948)	(822,733)	(79,451)	(846,975)	(113,876)	(410,775)	(249,282)	(11)	(1,741)	(1,913)	(51)	(2,135)	
Distribution Plant	(3,422,008)	(899)	(3,422,002)	(12,243)	(1,320,795)	(134,898)	(1,039,628)	(1,064,251)	(405,881)	(74,444)	(238,855)	(21,298)	(5)	(51,038)	(114,629)	(802)	(2,518)	
Total	751,195,569	747,559	750,948,010	891,097	70,789,959	8,043,618	63,189,481	7,357,590	-9,413,847	8,672,492	20,818,690	19,876,197	349	599,457	600,753	18,213	145,784	
Rate Base Adjusted For Ratemaking	Production Plant	1,395,210,021	1,381,346	1,393,848,676	4,930,311	394,111,156	48,879,239	35,131,916	40,833,513	273,491,247	47,685,475	114,989,523	109,071,603	1,923	3,530,915	3,880,486	103,220	812,848
Transmission Plant	171,921,489	182,194	171,759,295	487,848	40,112,410	3,507,254	45,177,220	4,357,570	39,480,854	6,745,042	22,285,245	13,872,088	50	95,470	104,912	2,781	117,092	
Distribution Plant	801,708,013	241,622	801,466,391	2,885,521	302,122,733	27,813,684	285,728,940	25,122,868	117,812,680	17,980,257	58,166,080	7,498,657	1,150	9,571,702	21,208,871	188,125	590,859	
Total	2,368,919,523	1,765,172	2,367,154,351	8,291,477	741,790,375	88,000,897	602,175,298	70,313,771	-26,707,789	71,921,874	195,428,848	130,240,408	3,173	13,198,087	25,192,768	292,136	1,520,801	
Adjusted Return for Ratemaking @9.75%	Production Plant	134,079,803	130,825	133,948,858	474,572	37,893,302	4,697,295	33,781,789	3,974,101	28,202,509	4,582,574	11,050,493	10,481,789	105	339,321	372,915	9,919	78,115
Transmission Plant	18,521,955	15,887	18,508,068	44,941	3,674,029	337,047	4,338,776	418,763	3,489,998	600,708	2,139,690	1,313,888	5	9,175	10,882	268	11,253	

POOR ORIGINAL

**COST OF SERVICE STUDY
(1996)**

	Total Utility	PERC JURIS.	PA PUC JURIS.	EA	ES	BH	GRGM	GMH	OL	OLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
Distribution Plant	<u>77,051,828</u>	<u>73,223</u>	<u>77,028,007</u>	<u>277,289</u>	<u>28,518,000</u>	<u>2,653,887</u>	<u>18,770,551</u>	<u>2,414,280</u>	<u>11,321,799</u>	<u>1,728,912</u>	<u>5,589,780</u>	<u>720,429</u>	<u>110</u>	<u>919,841</u>	<u>2,027,980</u>	<u>17,882</u>	<u>58,782</u>
Total	<u>\$227,852,186</u>	<u>\$169,693</u>	<u>\$227,483,533</u>	<u>\$798,811</u>	<u>\$71,288,672</u>	<u>\$7,688,099</u>	<u>\$57,899,049</u>	<u>\$9,787,152</u>	<u>\$41,014,397</u>	<u>\$9,911,692</u>	<u>\$18,779,942</u>	<u>\$12,516,103</u>	<u>\$300</u>	<u>\$1,268,338</u>	<u>\$2,420,977</u>	<u>\$28,074</u>	<u>\$146,148</u>
Power Production (O&M) Expenses																	
(1) Production Plant Expense	\$374,043,840	\$369,847	\$373,973,993	\$1,167,878	\$88,210,708	\$11,090,329	\$86,548,600	\$10,448,575	\$80,444,638	\$13,191,595	\$38,309,330	\$32,111,098	\$448	\$974,794	\$1,005,299	\$26,751	\$301,810
(2) Transmission Plant Expense	11,112,079	10,702	11,101,377	30,857	2,859,951	231,420	2,874,410	287,527	2,341,342	412,108	1,240,499	902,128	3	8,299	8,922	184	7,726
(3) Distribution Plant Expense	38,601,510	8,031	38,592,479	148,425	15,488,032	1,418,441	9,685,588	1,981,431	4,708,880	584,223	1,621,942	1,334,383	83	575,508	1,212,155	11,541	24,333
Total	<u>424,657,429</u>	<u>389,580</u>	<u>423,667,849</u>	<u>1,345,158</u>	<u>116,368,284</u>	<u>12,741,190</u>	<u>99,209,770</u>	<u>11,778,482</u>	<u>87,484,639</u>	<u>14,107,926</u>	<u>41,571,771</u>	<u>34,947,589</u>	<u>512</u>	<u>1,498,599</u>	<u>2,224,375</u>	<u>38,476</u>	<u>343,869</u>
Co-points and Accounting Expense																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	39,197,755	61	39,197,694	170,411	30,279,855	1,386,779	6,588,016	443,779	208,289	32,534	14,781	2,381	62	31	22,124	432	52,240
TOTAL CO-POINTS & ACCOUNTING EXPENSE	<u>39,197,755</u>	<u>61</u>	<u>39,197,694</u>	<u>170,411</u>	<u>30,279,855</u>	<u>1,386,779</u>	<u>6,588,016</u>	<u>443,779</u>	<u>208,289</u>	<u>32,534</u>	<u>14,781</u>	<u>2,381</u>	<u>62</u>	<u>31</u>	<u>22,124</u>	<u>432</u>	<u>52,240</u>
General Expense																	
Production	60,049,381	58,857	59,990,424	200,051	16,387,877	1,942,769	14,507,592	1,717,198	12,332,749	2,003,958	5,557,937	4,926,741	77	149,379	164,163	4,388	41,841
Transmission	7,354,792	2,253	7,352,537	8,502	580,481	48,761	678,892	60,583	493,329	88,833	274,642	190,802	1	1,327	1,459	39	1,828
Distribution	30,422,771	7,609	30,415,002	113,780	12,081,760	1,099,315	7,689,780	858,495	3,318,380	478,589	1,849,505	1,163,416	48	440,308	942,524	8,528	25,738
TOTAL GENERAL EXPENSE	<u>97,826,944</u>	<u>68,719</u>	<u>97,808,043</u>	<u>322,333</u>	<u>29,010,031</u>	<u>3,089,164</u>	<u>22,820,174</u>	<u>2,636,186</u>	<u>16,744,457</u>	<u>2,649,356</u>	<u>7,402,084</u>	<u>6,274,239</u>	<u>126</u>	<u>591,115</u>	<u>1,109,146</u>	<u>12,932</u>	<u>69,000</u>
O&M, Corp. Acct., & General Expense																	
Production	334,393,221	478,804	333,964,417	1,387,920	114,570,579	13,033,117	101,057,302	12,198,723	87,777,386	15,275,551	44,067,266	37,031,039	523	1,064,443	1,169,461	31,119	340,451
Transmission	13,466,871	12,557	13,454,313	37,358	3,220,411	780,881	3,901,302	348,110	2,834,671	498,941	1,515,141	1,092,710	4	7,527	8,381	223	9,354
Distribution	108,272,038	16,711	108,255,256	130,883	57,058,192	3,994,535	23,957,358	2,382,615	8,833,528	1,015,328	3,886,208	3,188,161	173	1,015,945	2,126,803	20,499	112,311
TOTAL O&M EXPENSES (1-3-7-9)	<u>\$556,132,128</u>	<u>\$498,072</u>	<u>\$555,623,586</u>	<u>\$1,555,000</u>	<u>\$175,857,182</u>	<u>\$17,217,033</u>	<u>\$128,815,360</u>	<u>\$14,858,447</u>	<u>\$104,445,585</u>	<u>\$16,789,818</u>	<u>\$49,066,615</u>	<u>\$41,224,210</u>	<u>\$700</u>	<u>\$2,087,714</u>	<u>\$3,354,645</u>	<u>\$51,840</u>	<u>\$465,117</u>
Depreciation & Amortization Expense																	
(1) Production Plant Expense	\$228,409,836	\$222,851	\$228,186,985	\$808,983	\$84,577,389	\$8,008,610	\$57,539,581	\$6,886,504	\$44,750,234	\$7,005,295	\$18,799,988	\$17,846,852	\$315	\$578,152	\$636,391	\$16,901	\$102,799
(2) Transmission Plant Expense	8,144,059	5,800	8,138,251	16,746	1,443,537	125,950	1,615,016	156,039	1,270,630	223,648	785,936	489,579	2	3,419	2,757	100	4,193
(3) Distribution Plant Expense	35,190,433	10,252	35,178,176	124,192	13,228,038	1,180,825	8,395,680	1,048,148	4,981,905	762,908	2,452,150	328,535	50	982,030	2,247,925	8,484	26,249

POOR ORIGINAL

COST OF SERVICE STUDY

(1996)

	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BS	BH	GRDM	QMH	QL	QLH	L	HVES	AL	SE	SM	SH	TRAFFIC SIGNALS
Total	270,352,328	230,815	270,113,410	949,801	79,248,968	9,321,031	67,890,286	7,890,891	51,012,849	8,791,649	22,043,134	18,884,985	307	1,563,601	2,887,123	25,405	183,241
Corporate & Acct. Dep. & Amortization																	
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(A) TOTAL CORPORATE & ACCOUNTING DEPR.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Plant Depreciation & Amortization																	
Production	11,416,869	11,140	11,405,728	40,389	3,225,026	399,711	2,073,810	334,071	2,238,069	390,257	941,942	892,892	14	28,689	31,749	845	8,002
Transmission	450,310	424	449,885	1,223	105,430	9,170	118,012	11,396	92,801	16,334	58,921	35,757	0	250	274	7	306
Distribution	7,111,599	2,028	7,109,523	25,422	2,744,048	242,445	1,808,713	218,668	1,808,690	154,664	491,255	65,024	14	100,020	238,152	1,068	5,228
(B) TOTAL GENERAL PLANT DEPR. & AMORT.	18,978,777	13,604	18,965,136	67,042	6,075,103	651,329	4,798,535	564,135	3,341,361	561,256	1,492,618	993,074	28	135,159	270,175	2,519	12,197
Depreciation & Amortization Expense																	
Production	239,876,705	233,991	239,592,713	849,352	67,803,020	8,408,377	60,413,391	7,070,575	46,989,103	8,195,552	19,741,930	16,739,744	331	607,041	667,140	17,746	139,461
Transmission	6,594,369	6,232	6,588,136	17,969	1,548,967	134,763	1,733,020	167,435	1,363,431	239,983	844,917	525,306	2	3,668	4,031	107	4,109
Distribution	42,910,032	12,332	42,897,699	149,630	15,972,080	1,429,221	10,202,401	1,286,016	6,001,675	917,571	2,948,905	393,559	61	1,000,050	2,480,122	10,021	31,422
TOTAL DEPR. & AMORT. EXCLUSIVE OF 2+3+4+5	289,331,105	252,555	289,078,549	1,016,950	85,324,073	9,972,361	72,348,820	8,454,027	54,354,210	9,353,105	23,535,752	19,658,639	393	1,690,759	3,157,298	27,924	175,432
Total O&M And Dept. Amort. Expense																	
Production	674,219,925	662,785	673,557,130	2,717,278	107,301,599	21,441,444	161,170,893	19,167,298	139,766,409	23,471,100	63,809,198	55,771,583	853	1,671,214	1,836,601	46,864	482,913
Transmission	20,061,209	19,109	20,042,090	55,377	4,769,378	414,944	5,334,330	515,545	4,198,102	738,922	2,360,050	1,617,545	6	11,295	12,412	330	13,853
Distribution	151,182,068	28,113	151,153,955	589,233	23,830,270	5,333,006	34,159,757	3,610,431	14,835,203	1,932,692	6,435,112	3,493,720	214	2,103,995	1,662,929	30,570	142,288
TOTAL O&M AND DEPR. AMORT. EXCLUSIVE	845,463,202	711,098	844,752,125	3,361,888	115,901,255	27,189,394	180,664,981	23,393,274	158,799,725	27,142,923	72,604,368	60,802,849	1,120	3,786,504	4,511,943	77,768	640,554
Taxes																	
Production	71,876,447	38,037	71,837,610	247,363	24,432,715	2,318,892	18,350,735	2,135,405	11,810,390	1,924,867	5,895,955	2,500,296	89	681,880	1,474,839	11,939	49,896
Transmission	2,009,519	1,988	2,007,931	10,298	977,672	102,975	706,528	85,487	487,377	81,476	199,174	141,789	4	21,719	41,848	409	1,774
Distribution	28,124,555	21,802	28,102,673	90,629	7,268,529	824,124	6,822,255	763,954	4,001,202	635,683	2,218,329	1,807,842	33	116,813	208,281	2,614	16,272

POOR ORIGINAL

COST OF SERVICE STUDY

(1996)

	Total Liberty	FERC JURIS.	PA PUC JURIS.	RA	RS	RH	RRGM	GMH	OL	OLH	L	MYPS	AL	SE	SM	SH	TRAFFIC SIGNALS
TOTAL TAXES	100,810,921	62,707	100,740,214	348,290	33,148,867	2,295,942	25,679,058	2,984,846	17,181,975	2,841,775	8,311,515	4,329,932	127	619,912	1,722,967	14,962	67,948
Total O&M, Depn, Amort. And Tax																	
Production	746,098,372	701,832	745,394,740	2,464,041	206,814,315	23,740,338	179,820,988	21,322,703	151,579,879	25,395,770	69,705,162	58,271,879	943	2,353,094	3,311,440	60,603	532,806
Transmission	22,871,158	21,178	22,849,980	65,826	5,097,050	517,809	6,040,058	601,032	4,885,480	820,349	2,559,232	1,759,305	10	32,514	54,260	740	18,627
Distribution	177,306,623	56,895	177,255,628	670,862	81,818,852	8,207,930	80,787,812	8,374,385	19,716,411	2,768,579	8,851,489	5,181,568	267	2,220,808	8,883,210	33,188	160,065
TOTAL O&M, DEPN, AMORT. AND TAX	946,274,154	779,805	945,500,348	3,201,129	294,130,221	32,466,138	226,649,839	26,298,121	175,981,770	28,984,698	80,915,683	65,212,781	1,220	24,606,415	18,234,910	64,727	706,500
Cost of Service (Summary)																	
Production Cost	680,178,055	682,457	679,242,598	42,939,212	424,707,617	428,457,631	421,582,737	425,748,804	417,882,388	429,978,344	460,755,655	468,793,667	61,127	42,692,414	43,684,355	470,723	661,973
Less: Off-System Revenues	(34,245,484)	(33,418)	(34,712,048)	(121,159)	(9,875,475)	(1,198,954)	(8,820,125)	(1,002,062)	(8,715,599)	(1,170,596)	(2,825,401)	(2,878,725)	(47)	(88,654)	(95,733)	(2,533)	(19,984)
Less: Other Revenues	(17,225,428)	(17,228)	(17,208,129)	(62,702)	(5,098,568)	(829,560)	(4,861,288)	(518,668)	(3,425,599)	(605,901)	(1,482,428)	(1,388,271)	(24)	(44,852)	(49,232)	(1,313)	(10,244)
Total Retail Production Cost	628,707,143	631,811	627,322,421	2,755,295	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180	230,024,180
21 Add: Gross Receipts Tax	21,764,574	23,027	21,741,547	89,980	10,069,444	692,890	3,919,516	583,771	2,632,511	700,162	1,852,571	740,262	29	83,102	379,275	4,453	42,368
Total Retail Production Cost w/GRIT	649,969,690	654,838	649,063,968	2,845,275	240,093,624	230,717,070	233,943,696	230,607,951	232,656,691	230,724,342	231,876,751	230,764,442	230,053	230,107,582	230,403,455	234,477	272,348
Transmission Cost	39,392,613	38,784	39,358,049	110,566	9,571,079	854,916	10,377,584	1,019,785	6,095,478	1,420,555	4,698,922	3,073,220	15	41,689	64,342	1,008	28,879
Less: Off-System Revenues	(2,254,574)	(2,124)	(2,252,450)	(6,123)	(527,858)	(45,925)	(590,853)	(57,050)	(464,831)	(81,781)	(295,002)	(179,024)	(1)	(1,250)	(1,374)	(37)	(1,533)
Less: Other Revenues	(6,248,052)	(6,248)	(6,248,052)	(16,000)	(1,482,581)	(172,245)	(1,832,104)	(158,095)	(1,282,375)	(226,598)	(812,375)	(488,631)	(2)	(3,488)	(3,908)	(101)	(6,248)
Total Transmission Cost	30,890,087	30,412	30,857,547	87,433	7,500,660	681,747	8,149,627	804,641	6,343,471	1,112,178	3,506,546	2,398,165	13	38,975	59,162	910	21,096
21 Add: Gross Receipts Tax	867,691	918	866,773	3,587	461,440	27,816	156,260	79,273	634,571	27,913	73,873	29,512	1	3,313	13,127	170	1,730
Total Retail Transmission Cost w/GRIT	31,757,778	31,410	31,724,320	91,020	7,962,100	709,562	8,305,887	883,914	6,978,042	1,140,091	3,680,419	2,427,677	13	42,288	72,289	1,170	22,826
Distribution Cost	254,350,451	74,216	254,276,236	948,161	111,138,157	8,081,597	60,552,564	6,788,676	31,038,210	4,497,491	14,241,249	5,901,996	378	3,140,648	6,907,191	51,071	218,847
Less: Off-System Revenues	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Other Revenues	(14,108,202)	(14,108)	(14,108,188)	(50,863)	(5,482,184)	(488,924)	(3,584,271)	(433,802)	(2,003,868)	(308,030)	(825,566)	(420,990)	(20)	(2,032,771)	(1,772,452)	(3,208)	(10,322)
Total Retail Distribution Cost	240,241,849	70,098	240,168,048	937,898	105,656,373	7,592,673	56,968,293	6,354,872	29,034,342	4,189,461	13,785,683	5,772,888	258	2,939,321	6,431,734	47,763	208,475
21 Add: Gross Receipts Tax	13,921,512	14,300	13,907,212	55,901	6,755,787	430,342	2,429,048	262,675	1,825,480	434,905	1,151,181	469,097	14	51,678	201,566	7,787	28,955
Total Retail Distribution Cost w/GRIT	254,163,361	84,398	254,075,260	993,800	112,412,160	8,023,015	59,397,341	6,617,547	30,859,822	4,624,366	14,936,864	6,241,985	272	2,991,000	6,633,300	55,550	237,430
Total Retail Trans. & Dist. Cost	795,530,730	114,077	795,418,656	1,044,663	119,932,760	9,520,378	67,709,261	7,545,461	37,119,044	5,765,731	18,077,287	8,660,577	305	3,027,271	6,711,589	51,577	256,258
Total Retail Prod. Trans. & Dist. Cost	11,135,500,423	4918,850	11,134,501,573	63,889,997	436,025,890	638,051,116	427,129,591	631,855,305	420,742,348	634,867,746	690,398,070	674,089,949	61,464	15,666,748	110,580,693	612,298	4880,241
Total L&Wh's	12,408,325,000	12,800,000	12,393,517,000	33,848,000	2,977,268,000	309,038,000	2,671,147,000	320,258,000	2,084,887,000	455,270,000	1,509,874,000	1,201,824,000	13,000	28,618,000	31,440,000	837,000	11,639,000
Average Retail Costs (\$/kWh)																	
Retail Production Cost	40.0885	40.0628	40.0885	40.0841	40.0006	40.0884	40.0780	40.0741	40.0590	40.0635	40.0519	40.0544	40.0829	40.0924	40.1236	40.0857	40.0536
Retail Transmission Cost	0.0026	0.0023	0.0026	0.0027	0.0027	0.0023	0.0032	0.0025	0.0022	0.0025	0.0024	0.0020	0.0010	0.0014	0.0023	0.0013	0.0020

POOR ORIGINAL

COST OF SERVICE STUDY

(1996)

	Total MWh	FERC JURIS.	PA PUC JURIS.	BA	BS	BH	GS/OM	GMH	QL	QLH	L	HVES	AL	SE	SM	BH	TRAFFIC SIGNALS
Retail Distribution Cost	0.0205	0.0068	0.0205	0.0262	0.0376	0.0285	0.0227	0.0205	0.0108	0.0102	0.0098	0.0052	0.0286	0.1042	0.2111	0.0604	0.0201
Retail Trans. & Distr. Cost	0.0230	0.0089	0.0230	0.0309	0.0403	0.0306	0.0256	0.0230	0.0129	0.0127	0.0120	0.0072	0.0296	0.1056	0.2134	0.0616	0.0220
Retail Total Cost (\$/KWh)	0.0915	0.0717	0.0915	0.1149	0.1208	0.1192	0.1030	0.0976	0.0719	0.0762	0.0639	0.0616	0.1128	0.1980	0.3365	0.1468	0.0750
Alloc																	
Total Retail Production Cost	880,176,055	832,457	879,343,598	2,939,212	244,707,617	26,457,631	213,592,737	25,246,804	177,862,088	29,978,344	60,755,655	68,753,667	1,127	2,692,414	3,684,355	70,723	610,923
# Production Energy (501,509, 518, 547, 555)	216,884,908	218,007	216,468,901	610,126	53,667,081	5,570,595	46,884,506	5,826,239	49,527,428	7,802,418	25,501,777	19,780,882	228	515,858	566,886	15,009	209,808
100 less: OH-System Sales	(33,975,902)	(33,153)	(33,942,749)	(120,186)	(9,599,265)	(1,169,517)	(8,552,282)	(994,175)	(6,662,737)	(1,161,381)	(2,803,161)	(2,457,193)	(47)	(63,972)	(94,483)	(2,513)	(19,627)
100 less: Transmission Off-System Sales Loss Revenue	(265,582)	(283)	(268,239)	(54)	(28,160)	(8,438)	(82,853)	(7,888)	(52,882)	(9,214)	(22,240)	(21,082)	(6)	(582)	(150)	(230)	(132)
Net Production Energy	182,439,444	182,591	182,256,854	489,971	43,991,657	4,371,040	38,244,970	4,834,177	42,811,829	6,631,822	22,678,577	17,102,607	181	429,204	471,634	12,558	189,824
12.4 less: Transmission Loss - Energy	1,429,714	1,425	1,628,089	4,589	403,837	41,897	352,474	43,895	372,502	58,880	191,802	148,774	2	3,880	4,263	113	1,578
12.6 less: Distribution Loss - Energy	10,438,542	4,345	10,432,197	44,308	3,897,997	404,574	3,111,184	387,234	1,708,925	259,005	549,277	8	12	37,466	41,168	1,097	15,244
12 less: Spinning Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Production Energy Less Loss & Ancillary	170,373,189	178,621	170,196,568	440,679	39,690,323	3,925,170	34,780,212	4,428,048	40,730,402	6,314,135	21,835,298	16,953,824	167	387,858	426,203	11,345	173,002
Production Capacity Cost	663,491,147	616,451	662,674,096	2,329,086	191,040,525	22,887,037	168,718,232	18,410,584	128,334,960	22,175,926	55,253,878	48,972,786	899	2,176,556	3,117,488	55,634	401,115
less: Other Revenue	(17,725,476)	(17,298)	(17,708,179)	(62,707)	(5,008,008)	(620,580)	(4,481,788)	(516,868)	(3,475,996)	(605,901)	(1,462,429)	(1,388,277)	(24)	(4,852)	(49,292)	(1,311)	(10,344)
Net Production Capacity Cost	645,765,672	599,155	645,106,517	2,266,379	186,032,529	22,266,457	164,256,444	18,894,896	124,858,964	21,570,025	53,791,448	47,584,509	875	2,131,704	3,068,196	54,323	390,771
129 less: Transmission Loss - Demand	2,652,834	2,472	2,651,362	9,319	783,421	81,611	666,898	77,639	513,663	86,796	220,504	198,454	4	6,808	12,220	221	1,602
129 less: Distribution Loss - Demand	18,456,212	7,190	18,439,022	64,813	5,309,247	637,112	4,637,971	539,946	3,572,296	617,552	1,536,287	1,368,250	25	59,865	84,981	1,539	11,139
129 less: Reactive Power	4,021,675	3,748	4,017,929	14,123	1,158,904	138,029	1,010,831	117,856	778,416	134,567	334,782	297,711	5	13,045	10,518	335	2,427
129 less: Regulation & Frequency Control	5,187,040	4,631	5,182,208	10,715	1,492,141	179,058	1,303,482	151,748	1,003,979	173,560	431,767	383,979	7	16,825	23,884	432	3,130
129 less: Operating Spinning Reserve	8,913,285	8,302	8,904,983	31,201	7,564,054	307,607	2,239,867	260,762	1,725,209	298,741	741,936	659,819	12	28,911	41,041	743	5,379
129 less: Operating Reserve Supplemental (O.S.)	3,887,219	3,269	3,878,010	34,721	2,884,229	341,209	2,484,818	289,255	1,813,723	336,830	823,088	731,917	13	32,021	45,526	624	5,987
Total Net Retail Production Cost	598,046,427	553,405	598,093,021	2,093,887	171,907,532	20,570,852	149,912,978	17,454,888	115,351,675	19,976,477	49,702,785	43,950,379	808	1,972,379	2,847,027	50,228	361,127
Generation Products & Schedule																	
12.4 add: Transmission Loss - Energy	1,429,714	1,425	1,628,089	4,589	403,837	41,897	352,474	43,895	372,502	58,880	191,802	148,774	2	3,880	4,263	113	1,578
12.6 add: Transmission Loss - Demand	2,652,834	2,472	2,651,362	9,312	657,204	68,725	572,970	71,479	608,584	95,560	312,331	247,265	3	6,318	6,943	185	2,570
12.6 add: Distribution Loss - Energy	10,438,542	4,345	10,432,197	44,308	3,897,997	404,574	3,111,184	387,234	1,708,925	259,005	549,277	8	12	37,466	41,168	1,097	15,244
12.6 add: Distribution Loss - Demand	18,456,212	7,190	18,440,528	70,358	6,892,774	715,457	5,501,806	640,583	3,072,101	459,030	971,953	14	21	66,756	77,002	1,940	28,957
Ancillary Services																	
1 add: Reserve from Generation	4,021,675	3,748	4,017,929	14,123	1,158,904	138,029	1,010,831	117,856	778,416	134,567	334,782	297,711	5	13,045	10,518	335	2,427
1 add: Regulation & Frequency Control	5,187,040	4,632	5,181,978	14,594	1,258,089	159,454	1,408,109	135,881	1,107,378	194,914	518,796	426,677	7	7,979	3,774	87	3,054
1 add: Spinning Reserve	8,913,285	8,698	8,904,567	25,078	2,161,831	188,083	2,418,919	233,683	1,907,007	334,934	891,484	733,190	3	5,120	5,828	150	8,379
1 add: Reserve Supplemental (O.S.)	3,887,219	3,648	3,877,521	22,818	2,398,055	280,825	2,800,239	259,212	2,110,818	321,532	988,892	813,306	3	4,625	8,281	166	6,885
Subtotal Generation Products	61,105,501	43,457	61,142,048	216,340	18,828,251	1,875,155	17,052,711	1,884,737	11,009,608	1,907,224	4,758,702	2,661,945	50	140,743	158,034	4,073	65,675
Net Production Energy Less Loss & Ancillary	170,373,189	178,621	170,196,568	440,679	39,690,323	3,925,170	34,780,212	4,428,048	40,730,402	6,314,135	21,835,298	16,953,824	167	387,858	426,203	11,345	173,002
Total Net Retail Production Cost	598,046,427	553,405	598,093,021	2,093,887	171,907,532	20,570,852	149,912,978	17,454,888	115,351,675	19,976,477	49,702,785	43,950,379	808	1,972,379	2,847,027	50,228	361,127
Subtotal Generation Products	61,105,501	43,452	61,142,048	216,340	18,828,251	1,875,155	17,052,711	1,884,737	11,009,608	1,907,224	4,758,702	2,661,945	50	140,743	158,034	4,073	65,675
Total Retail Production Cost	659,151,928	596,857	659,235,069	2,310,227	190,735,783	22,446,007	166,965,689	19,343,625	126,361,283	21,883,701	54,461,487	46,612,324	858	2,113,122	3,005,061	54,301	426,802

POOR ORIGINAL

COST OF SERVICE STUDY

(1996)

	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	BSMM	QMH	GL	GLK	L	HVPS	AL	SE	BM	SH	TRAFFIC SIGNALS
add: Gross Receipts Tax	21,764,574	22,027	21,741,547	88,980	10,069,444	892,880	3,818,510	583,771	2,632,511	700,162	1,052,971	740,262	23	83,102	329,275	4,453	43,388
Total Retail Production Cost W/O RT	849,869,690	786,506	849,173,184	2,840,266	240,488,549	27,063,866	205,665,918	24,331,445	170,324,197	28,647,997	78,249,755	64,306,410	1,048	2,584,083	3,756,338	70,099	643,182
Net Production Energy Loss & Ancillary	170,370,189	176,021	170,196,568	440,078	39,890,323	3,825,170	34,760,712	4,426,048	40,730,402	6,314,135	21,935,298	10,953,824	187	387,850	426,203	11,345	173,002
Total Net Retail Production Cost	598,646,427	553,405	598,983,021	2,093,887	171,802,532	20,570,652	149,812,876	17,454,886	115,351,879	19,926,477	49,702,785	43,950,379	808	1,972,370	2,842,027	50,228	381,127
Net Reactive Power, Reg./Freq. Ctrl & Spinning Res.	18,121,980	17,503	18,104,475	53,288	4,538,865	438,388	4,832,858	487,330	3,788,681	684,414	1,745,642	1,457,520	10	21,144	27,418	52	12,381
Total Basic Service (F&W)	6,0633	0,0584	6,0633	0,0785	0,0726	0,0807	0,0723	0,0681	0,0554	0,0591	0,0486	0,0519	0,0758	0,0832	0,1048	0,0742	0,0470
Transmission Cost	39,392,810	36,764	39,356,046	110,566	9,571,079	854,916	10,377,584	1,019,795	6,095,478	1,420,555	4,898,922	3,073,220	15	41,089	64,342	1,008	26,879
less: Off-System Revenues	(2,254,574)	(2,124)	(2,252,450)	(6,123)	(577,858)	(45,925)	(590,853)	(57,059)	(484,631)	(81,781)	(285,002)	(179,024)	(1)	(1,250)	(1,374)	(37)	(1,533)
less: Other Revenues	(6,246,853)	(5,884)	(6,240,969)	(18,988)	(1,462,561)	(146,256)	(1,608,817)	(157,245)	(1,807,104)	(158,095)	(1,287,375)	(226,596)	(2)	(3,464)	(3,808)	(101)	(4,248)
add: Gross Receipts Tax	862,681	818	860,223	2,582	481,440	22,418	158,288	22,223	104,951	23,313	29,512	29,512	1	3,313	3,122	178	1,730
Total Retail Transmission Cost	31,759,076	29,674	31,729,402	91,064	7,982,100	709,702	8,305,887	827,914	6,448,422	1,140,992	3,660,418	2,427,677	13	40,288	72,289	1,048	22,828
less: Dispatch Out Of Account 501	(878,636)	(809)	(877,827)	(2,331)	(200,978)	(17,405)	(274,628)	(21,725)	(178,805)	(31,138)	(82,876)	(68,162)	(0)	(478)	(523)	(14)	(584)
add: Scheduling Out Of Account 501	828,636	809	827,827	2,331	200,978	17,405	274,628	21,725	178,805	31,138	82,876	68,162	0	478	523	14	584
Total Transmission Cost With Products	31,759,076	29,674	31,729,402	91,064	7,982,100	709,702	8,305,887	827,914	6,448,422	1,140,992	3,660,418	2,427,677	13	40,288	72,289	1,048	22,828
Distribution Cost	254,358,451	74,218	254,284,233	948,181	111,138,157	8,861,597	60,552,564	6,788,616	31,008,210	4,487,491	14,241,249	5,901,998	378	3,140,648	6,907,191	51,071	218,847
less: Off-System Revenues	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less: Other Revenues	(14,108,307)	(4,118)	(14,104,189)	(5,463)	(5,443,784)	(480,974)	(3,564,237)	(433,803)	(2,000,088)	(306,830)	(975,568)	(128,998)	(20)	(710,327)	(472,457)	(3,308)	(10,372)
add: Gross Receipts Tax	13,521,512	14,308	13,507,204	55,801	6,255,762	400,342	2,435,048	382,625	1,635,480	424,885	1,151,181	453,887	18	51,626	204,566	2,162	28,355
Total Retail Distribution Cost	253,771,657	64,403	253,687,253	953,599	111,950,160	8,810,966	59,403,374	6,717,547	30,670,627	4,675,645	14,416,684	6,232,895	372	2,981,949	6,639,300	50,529	233,430
less: Cust. Charges for FR, RA, IH, QM, QMH	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Distribution Cost	253,771,657	64,403	253,687,253	953,599	111,950,160	8,810,966	59,403,374	6,717,547	30,670,627	4,675,645	14,416,684	6,232,895	372	2,981,949	6,639,300	50,529	233,430
Retail Production Cost (E L&W)	0,0985	0,0927	0,0665	0,0839	0,0108	0,0076	0,0705	0,0741	0,0590	0,0634	0,0518	0,0505	0,0807	0,0903	0,1194	0,0838	0,0553
Bases For Retail Rates																	
Transmission																	
Reactive Power	4,021,675	3,746	4,017,929	14,123	1,156,904	128,829	1,010,031	117,858	778,416	134,587	334,762	297,711	5	13,045	18,518	335	2,427
Regulation & Frequency Control	5,107,040	4,031	5,102,909	18,215	1,492,141	179,050	1,303,482	151,749	1,063,919	173,560	431,767	383,919	7	16,875	23,884	437	3,136
Operating Spinning Reserve	8,911,755	0,307	8,904,953	31,301	2,584,054	307,687	2,739,067	280,782	1,725,209	298,241	741,936	659,819	1	28,911	41,641	743	5,379
Gross Receipts Tax	401,735	497	401,238	2,078	270,707	16,267	89,024	13,045	55,071	15,054	38,553	15,391	1	1,507	7,762	101	817
Total Retail Transmission Cost	31,759,076	29,674	31,729,402	91,064	7,982,100	709,702	8,305,887	827,914	6,448,422	1,140,992	3,660,418	2,427,677	13	40,288	72,289	1,048	22,828
Total	50,367,732	47,050	50,315,742	156,781	13,423,408	1,309,762	12,948,891	1,371,126	10,011,097	1,761,514	5,205,437	3,784,537	39	100,977	163,493	2,659	34,582
E L&W	0,0041	0,0037	0,0041	0,0044	0,0045	0,0044	0,0049	0,0042	0,0035	0,0039	0,0034	0,0031	0,0030	0,0035	0,0057	0,0037	0,0030
Distribution																	
Loss Drmitt	10,458,712	17,190	10,439,022	64,811	5,309,247	637,112	4,637,971	539,946	3,572,296	617,552	1,538,287	1,366,250	25	59,065	84,981	1,539	11,139

POOR ORIGINAL

COST OF SERVICE STUDY
(1996)

	Total USD\$	FERC JURIS	PA PUC JURIS	BA	BS	BH	GRDM	GMH	GL	GLH	L	HYES	AL	SE	SM	SH	TRAFFIC SIGNALS
Loss Energy	10,430,542	4,345	10,432,197	44,308	3,897,697	404,574	3,111,184	382,234	1,708,925	258,005	549,277	8	12	37,466	41,188	1,097	15,244
Gross Receipts Tax	785,901	634	785,266	3,563	403,039	27,086	15,185	22,196	82,918	21,782	50,537	15,635	1	3,158	11,734	175	1,972
Total Distribution Cost	<u>253,111,852</u>	<u>84,403</u>	<u>253,087,253</u>	<u>853,588</u>	<u>111,850,160</u>	<u>8,810,868</u>	<u>59,407,374</u>	<u>8,717,542</u>	<u>30,670,622</u>	<u>4,425,845</u>	<u>14,418,884</u>	<u>8,232,895</u>	<u>372</u>	<u>2,981,949</u>	<u>4,639,300</u>	<u>50,528</u>	<u>232,430</u>
Total	<u>283,480,311</u>	<u>100,572</u>	<u>283,359,739</u>	<u>1,086,283</u>	<u>121,560,144</u>	<u>9,879,739</u>	<u>87,904,014</u>	<u>7,641,925</u>	<u>38,034,701</u>	<u>5,523,984</u>	<u>16,552,985</u>	<u>7,614,780</u>	<u>410</u>	<u>3,082,439</u>	<u>6,777,183</u>	<u>53,340</u>	<u>261,784</u>
\$/kWh	0.0228	0.0083	0.0228	0.0315	0.0408	0.0320	0.0257	0.0233	0.0125	0.0121	0.0110	0.0063	0.0315	0.1077	0.2155	0.0837	0.0225

EXHIBIT JAL-1A
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POOR ORIGINAL

Schedule B

Cost of Service Study Results (By FERC Account)

(Pages 1-23)

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total WHY	PERC JURIS.	PA-PUC JURIS.	BA	BR	BH	Q/DM	QMH	SL	SLH	L	HYFE	AL	RE	SM	RH	TRAFFIC SIGNALS	
ELECTRIC PLANT IN SERVICE																			
Intangible Plant (P204)																			
301	Total Organization	100,275																	
	Production	100	60,321	59	60,263	213	17,043	2,112	15,184	1,765	11,928	2,082	4,977	4,718	0	153	188	4	35
	Transmission	101	2,379	2	2,377	6	557	49	624	60	490	86	311	189	0	1	1	0	2
	Distribution	102	37,674	11	37,563	134	14,498	1,281	9,546	1,155	6,335	817	2,598	344	0	580	1,258	8	28
302	Total Franchises & Consents	8,330																	
	Production	100	4,109	4	4,105	16	1,181	144	1,034	120	806	140	339	321	0	10	11	0	2
	Transmission	101	182	0	182	0	38	3	42	4	33	6	21	13	0	0	0	0	0
	Distribution	102	2,559	1	2,558	9	987	87	650	79	363	68	177	23	0	38	86	1	2
303	Total Miscellaneous Intangible Plant	43,893,420																	
	Production	100	26,484,871	25,824	26,438,848	93,624	7,477,105	928,544	6,661,685	774,387	5,189,771	804,628	2,183,451	2,068,753	38	88,985	73,585	1,958	15,443
	Transmission	101	1,943,952	993	1,942,949	7,825	244,380	21,282	273,556	28,417	215,117	37,884	138,681	82,885	0	578	838	17	710
	Distribution	102	16,464,618	4,812	16,480,104	58,964	8,360,781	581,898	4,188,019	508,880	2,340,484	358,617	1,139,805	150,729	23	245,758	652,044	3,865	12,118
	Total Intangible Plant		44,100,525	31,886	44,068,829	155,801	14,116,670	1,513,478	11,150,239	1,310,888	7,784,239	1,304,177	3,488,360	2,308,875	60	314,085	627,800	5,854	28,341
Total Intangible Plant - Class Percentage		100%	0.0719%	99.9281%	0.3553%	32.0100%	3.4319%	25.2837%	2.9725%	17.6056%	2.9573%	7.8647%	5.2357%	0.0001%	0.7122%	1.4236%	0.0133%	0.0643%	
Intangible Plant Summary																			
	Production	26,529,102	25,887	26,503,215	93,852	7,495,309	928,800	6,677,803	776,273	5,202,406	808,831	2,189,787	2,074,782	37	87,128	73,774	1,962	15,483	
	Transmission	1,046,373	986	1,046,388	2,842	244,985	21,314	274,222	28,482	216,641	37,958	138,814	83,087	0	580	838	17	712	
	Distribution	16,525,049	4,824	16,520,226	58,107	8,378,277	583,384	4,198,215	508,114	2,346,192	359,390	1,142,680	151,088	23	246,358	653,388	3,875	12,148	
	Total	44,100,525	31,888	44,068,829	155,801	14,116,670	1,513,478	11,150,239	1,310,888	7,784,239	1,304,177	3,488,360	2,308,875	60	314,085	627,800	5,854	28,341	
Production Plant																			
A: Steam Production Plant																			
310	Land & Land Rights	32	8,028,780	7,805	8,018,855	29,319	2,312,380	292,816	2,085,771	237,847	1,532,853	272,041	617,257	611,035	11	20,502	22,532	599	4,192
311	Structures & Improvements		128,853,875																
312	Boiler Plant Equipment		484,460,835																
313	Engines and Engine Driven Motors		0																
314	Turbogenerators		115,768,800																
315	Accessory Electric Equipment		78,728,368																
316	Misc Power Plant Equipment		24,280,712																
	Total A/C 311-316		837,093,588																
	Energy	12	158,824,071	158,427	158,765,845	447,487	39,381,260	4,085,663	34,372,020	4,280,498	36,325,098	5,722,658	18,703,870	14,507,970	187	378,348	416,759	11,067	153,880
	Demand	32	673,169,517	654,604	672,514,912	2,458,875	103,928,258	24,565,497	173,247,261	19,947,235	128,528,563	22,814,871	51,768,842	51,244,814	862	1,719,418	1,889,877	50,260	351,579
	Total Steam Production Plant		840,120,348	820,836	839,289,512	2,935,692	235,602,898	28,944,076	208,885,052	24,465,578	168,398,214	28,809,470	71,087,768	66,363,819	1,141	2,118,268	2,327,968	61,926	509,651
B: Nuclear Production Plant																			
320	Land & Land Rights	32	617,803	601	617,302	2,257	178,008	22,548	159,024	18,310	117,977	20,842	47,517	47,038	1	1,578	1,735	46	323
321	Structures & Improvements		228,416,299																
322	Reactor Plant Equipment		999,158,421																
323	Turbogenerators		119,728,878																
324	Accessory Electric Equipment		181,470,278																
325	Misc Power Plant Equipment		72,991,217																
	Total B/C 321-325		1,482,761,041																
	Energy	12	184,231,399	183,717	184,067,882	482,431	40,875,744	4,222,108	35,519,886	4,423,445	37,538,188	5,813,855	18,328,492	14,882,470	173	390,983	428,643	11,438	159,019
	Demand	32	1,318,528,642	1,282,168	1,317,247,476	4,816,172	379,847,080	48,116,166	339,337,483	39,070,427	251,747,487	44,687,234	101,394,745	100,372,647	1,864	3,367,805	3,701,288	98,444	688,634

COST OF SERVICE STUDY
(By FERC Account - 1996)

FERC ACCT	Description of Account	Total MURK	FERC JURIL	PA PUC JURIL	BA	BE	BN	QWQM	QWMI	GL	GLH	L	HYPR	AL	SE	EM	SH	TRAFFIC SIGNALS
	Total Nuclear Production Plant	1,485,378,944	1,448,484	1,481,932,460	5,280,860	420,700,832	52,360,820	376,018,393	43,812,181	289,403,831	60,821,841	120,770,754	116,412,165	2,058	3,780,368	4,132,687	109,928	847,978
	D: Other Production Plant																	
340	Land & Land Rights	393,704	383	393,321	1,438	113,420	14,367	101,324	11,688	76,170	13,343	30,278	29,071	1	1,008	1,105	29	206
341	Structures & Improvements	8,160,271																
342	Fuel Holders, Products and Accessories	3,371,828																
343	Prime Movers	439,877																
344	Generators	22,778,984																
345	Accessory Electric Equipment	8,874,134																
346	Misc Power Plant Equipment	1,082,833																
	Total A/C 341-346	42,565,725																
	Energy	1,880,242	1,074	1,878,268	6,578	480,453	60,809	428,288	63,338	452,822	71,305	233,058	190,774	2	4,714	6,180	138	1,917
	Demand	40,625,483	39,408	40,486,075	148,027	11,874,737	1,478,888	10,428,880	1,200,844	7,737,649	1,373,478	3,118,404	3,084,889	58	163,511	113,760	3,028	21,185
	Total Other Production Plant	42,899,428	41,705	42,857,684	166,041	12,278,810	1,644,143	10,958,288	1,285,848	8,285,341	1,458,128	3,378,738	3,295,734	61	169,231	120,048	3,193	23,288
	Production Plant - Energy Related	326,135,713	324,118	324,911,585	916,485	80,527,457	8,358,878	70,320,182	8,767,277	74,316,808	11,707,529	38,285,418	29,881,214	343	774,045	850,583	22,841	314,917
	Production Plant - Demand Related	7,041,263,008	1,884,887	7,039,278,041	7,458,088	588,954,882	74,490,382	526,340,522	80,486,328	389,739,279	69,181,909	166,972,839	155,380,494	2,817	5,213,820	5,730,098	152,404	1,088,099
	Total Production Plant	7,368,348,721	2,309,085	7,364,089,638	8,371,563	669,582,339	82,849,039	596,880,714	89,243,608	464,055,188	80,889,437	195,238,257	185,071,708	3,259	5,987,865	6,580,681	175,045	1,380,916
	Total Production Plant - Class Percentage	100%	0.0976%	99.9024%	0.3538%	28.7532%	3.5011%	25.1716%	2.9261%	19.6102%	3.4183%	8.2504%	7.8208%	0.0001%	0.2530%	0.2781%	0.0074%	0.0584%
	Transmission Plant																	
350	Total Land and Land Rights	9,833,885																
	Substations 350.1	223,216	218	222,898	828	54,139	4,710	60,510	5,852	47,854	8,388	22,328	18,381	0	128	141	4	157
	Land & Land Rights 350.2																	
	Transmission - 69KV & Over	9,484,840	9,256	9,475,385	28,888	2,300,413	290,140	2,671,108	248,553	2,024,870	358,405	948,832	780,190	3	5,448	5,987	159	6,882
	Direct Assignment	125,728	0	125,229	0	0	0	18,883	0	0	0	108,545	0	0	0	0	0	0
352	Structures and Improvements	8,073,881																
353	Station Equipment	124,857,725																
	Total A/C 352-353	132,931,408																
	Generation Step-Up	28,812,925	28,117	28,784,809	81,088	6,988,313	807,895	7,810,843	755,400	8,151,253	1,082,704	2,881,802	2,370,102	8	16,550	18,187	484	20,288
	Transmission - 69KV & Over	95,815,572	93,599	95,821,974	268,888	23,263,448	2,023,858	26,000,811	2,514,658	20,478,954	3,604,223	8,583,254	7,889,851	29	55,094	60,542	1,611	87,571
	Subtransmission - 11.5/23KV	4,827,043	4,516	4,822,827	13,018	1,122,247	97,637	1,254,304	121,309	987,824	173,871	482,788	380,613	1	2,658	2,821	78	3,260
	All Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Directs	3,575,865	0	3,575,865	0	0	0	0	0	0	0	3,575,865	0	0	0	0	0	0
354	Towers & Fixtures	66,632,752																
355	Poles & Fixtures	5,853,323																
358	Overhead Conductor & Devices	43,875,550																
	Total A/C 354-358	116,261,625																
	Transmission - 69KV & Over	109,133,532	108,487	109,027,035	307,058	26,468,344	2,302,878	29,584,051	2,861,189	23,288,848	4,100,915	10,815,284	8,977,138	33	62,886	68,885	1,833	76,883
	Direct Assignment	7,128,093	0	7,128,093	0	0	0	105,280	0	0	0	7,022,833	0	0	0	0	0	0
357	Underground Conduit	34,250,803	33,423	34,217,480	98,368	8,307,245	722,744	9,284,777	897,970	7,312,203	1,287,048	8,425,686	2,817,421	10	18,874	21,819	575	24,129
358	Underground Conductors and Devices	18,895,858	18,439	18,877,419	53,165	4,593,018	398,730	5,122,312	485,401	4,034,085	710,050	1,889,920	1,554,341	6	10,854	11,927	317	13,312
359	Roads & Trails	13,878	14	13,865	39	3,368	293	3,782	364	2,883	522	1,388	1,142	0	8	9	0	10
	Total Transmission Plant	312,186,756	294,078	311,892,678	847,900	73,091,533	6,359,087	81,814,322	7,900,816	64,338,835	11,324,125	40,848,332	24,789,158	90	173,099	180,218	5,081	212,303
	Total Transmission Plant - Class Percentage	100%	0.0942%	99.9058%	0.2716%	23.4128%	2.0369%	26.2069%	2.5308%	20.6084%	3.6274%	13.0846%	7.9403%	0.0000%	0.0554%	0.0609%	0.0016%	0.0680%

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total WHY	FERC JURIS.	PAPUC JURIS.	BA	BR	BH	OR/OM	OMM	OL	OLH	L	HYPR	AL	BE	SM	SH	TRAFFIC SIGNALS
	Distribution Plan																	
360	Land & Land Rights	9,902,261																
	Production 360.1	375,655	365	375,290	1,372	108,220	13,709	96,679	11,131	71,724	12,732	28,888	28,597	1	960	1,055	28	108
	Network 360.1	511,441		511,441	0	0	0	104,270	18,688	281,285	47,001	59,288	0	0	0	0	0	0
	Subtransmission 360.1	3,185,889	3,200	3,182,389	12,427	980,084	128,891	850,011	121,329	859,309	114,888	205,767	0	5	8,441	9,277	247	1,728
	Distribution 360.1	2,550,990		2,550,990	15,222	1,200,550	167,885	970,126	109,208	87,123	8,752	0	0	8	10,340	11,364	302	2,114
	Land Rights 360.2	2,288,485	0	2,288,485	13,538	1,087,597	140,400	882,890	97,114	69,899	6,004	0	0	5	9,185	10,105	269	1,880
361	Structures & Improvement	41,029,378																
362	Station Equipment	318,018,298																
	Total Accounts 361-362	359,048,878																
	Transmission - 69KV & Over	89,894,989	87,416	89,807,673	329,358	25,897,293	3,280,474	23,135,422	2,683,762	17,193,691	3,046,696	8,912,912	8,843,227	128	228,811	252,347	8,712	48,950
	Subtransmission - 11.5/23KV	88,894,831	82,658	89,901,873	549,852	27,900,389	3,829,748	28,763,503	3,416,789	18,588,869	3,235,343	5,794,653	0	133	237,712	281,250	8,949	48,608
	Network	18,627,054		18,627,054	0	0	0	3,389,847	838,760	9,144,981	1,528,005	1,927,492	0	0	0	0	0	0
	Primary - 13.2/23KV	47,287,891	0	47,287,891	292,232	22,258,393	2,927,348	17,887,077	2,024,826	1,244,518	125,188	0	0	107	181,712	210,695	5,604	38,200
	Primary - 4KV	46,802,397	0	46,802,397	318,082	21,932,069	2,884,301	17,722,686	1,895,052	1,228,218	123,348	0	0	108	188,893	207,597	5,521	38,824
	Street Lighting	377,449	0	377,449	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Direct Assignment	88,251,265	0	88,251,265	0	285,348	0	4,329,309	27,333	17,218,625	268,070	48,122,590	0	0	113,177	284,272	0	0
363	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
364	Poles, Towers, Foundations	218,026,447																
365	Overhead Conductor & Devices	189,933,238																
	Total Overhead Lines 364-365	389,959,883																
	Subtransmission - 11.5/23KV	74,801,625	77,015	74,724,610	290,873	22,940,857	3,016,887	22,236,943	2,839,946	15,432,489	2,688,148	4,816,393	0	111	197,581	217,146	5,775	40,401
	Capacity	44,073,208	0	44,073,208	282,890	20,741,779	2,727,785	18,780,751	1,888,777	1,159,889	118,854	0	0	100	178,841	198,331	5,222	36,528
	Customer	48,748,816	69	48,748,816	195,252	34,238,357	1,571,872	3,554,367	232,319	43,611	7,372	1,309	0	138	2,690,474	4,041,327	58,013	118,435
	Primary - 4KV	80,787,545	0	80,787,545	382,128	28,807,998	3,782,244	23,112,104	2,602,319	1,588,483	180,894	0	0	138	248,389	270,787	7,202	59,381
	Customer	82,424,149	82	82,424,057	260,733	45,718,000	2,089,021	4,748,373	310,230	58,237	9,844	1,748	0	184	3,592,783	5,398,842	74,797	155,493
	Secondary	43,987,178	0	43,987,178	262,477	20,701,291	2,722,441	18,728,034	1,883,094	1,157,408	116,426	0	0	100	178,283	195,947	5,212	38,456
	Customer	44,774,335	70	44,774,285	189,125	34,815,395	1,603,048	3,531,625	218,923	8,958	703	0	0	141	0	4,121,492	57,124	118,744
	Street Lighting	9,364,732	0	9,364,732	0	0	0	0	0	0	0	0	0	0	2,807,989	6,556,743	0	0
366	Underground Conduit	74,581,251																
367	Underground Lines	112,818,827																
	Total Underground Lines 366-367	187,377,878																
	Subtransmission - 11.5/23KV	48,152,338	48,577	48,102,761	187,745	14,767,806	1,942,124	14,314,673	1,828,189	9,934,403	1,731,098	3,100,475	0	71	127,180	139,784	3,718	26,607
	Network	78,987,601	0	78,987,601	0	0	0	15,895,875	2,848,318	42,343,555	7,075,063	8,924,780	0	0	0	0	0	0
	Capacity	22,287,897	0	22,287,897	0	0	0	17,380,814	3,240,173	1,480,887	148,835	56,188	0	0	0	0	0	0
	Primary - 13.2/23KV	18,289,382	0	18,289,382	109,185	8,612,074	1,132,580	6,958,135	783,398	481,500	48,435	0	0	41	74,173	81,517	2,168	15,166
	Customer	5,297,667	8	5,297,659	22,127	3,878,889	178,135	402,804	28,328	4,842	835	148	0	18	304,902	457,990	6,348	13,195
	Secondary	12,881,657	0	12,881,657	75,873	5,868,255	784,889	4,822,751	542,903	333,884	33,586	0	0	28	51,402	58,492	1,503	10,511
	Customer	3,671,330	8	3,671,330	18,328	2,852,938	131,444	288,581	18,033	570	68	0	0	12	0	337,947	4,684	9,737
368	Line Transformers	130,946,402																
	Primary	20,227,095	0	20,227,095	120,697	9,519,297	1,251,889	7,692,232	865,823	532,222	53,538	0	0	46	81,886	90,105	2,397	16,784
	Secondary Network	20,621,775	0	20,621,775	0	0	0	4,183,884	785,902	11,287,076	1,885,825	2,378,987	0	0	0	0	0	0

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total MWh	FERC JURIS	PAPUC JURIS	BA	BB	BB	QBOM	QBH	QL	QLH	L	WVPL	AL	BE	BM	BN	TRAFIC SIGNALS	
	Capacity	4	68,410,043	37,327	89,372,716	252,843	31,114,787	1,730,863	13,893,482	1,924,140	10,171,560	1,803,548	3,838,387	3,821,588	54	95,781	105,243	2,789	19,581
	Customer	17	21,991,388	35	21,991,384	97,802	17,148,073	787,354	1,734,698	108,018	3,417	345	0	0	69	0	2,024,310	28,057	58,323
	Direct Assignment	64	19,786,091	0	19,786,091	0	2,881,578	183,089	5,025,228	1,242,750	8,831,168	1,852,315	0	0	0	0	0	0	0
369	Services		57,782,430																
	Capacity	4	12,603,940	8,877	12,606,965	48,802	6,732,677	318,894	2,659,728	354,603	1,874,004	295,437	708,914	687,240	10	17,843	10,380	518	3,808
	Customer	16	45,188,590	78	45,188,511	222,304	38,878,764	1,788,653	3,942,727	245,623	7,788	784	0	0	0	0	0	0	0
370	Miscellaneous	40	50,652,919	5,109	59,647,810	144,778	25,388,053	1,185,634	27,424,151	1,807,819	2,648,314	474,592	388,473	98,088	0	0	0	0	0
	Installations on Cust Premises	20	37,793	0	37,793	0	0	0	4,684	0	13,826	0	2,218	17,188	0	0	0	0	0
	Leased Property on Customer Premise	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
373	Street Lights & Signal Systems	19	27,810,888	0	27,810,888	0	0	0	0	0	0	0	0	0	0	0	8,748,788	15,780,920	0
	Total Distribution Plant		1,233,225,730	358,982	1,232,866,758	4,411,052	478,848,598	42,042,659	313,302,916	37,819,336	176,090,917	28,820,438	85,275,511	11,275,923	1,748	18,384,898	41,288,065	289,165	908,818
	Total Distribution Plant - Class Percentage		100%	0.0292%	99.9708%	0.3577%	38.5855%	3.4092%	25.4052%	3.0748%	14.1978%	2.1748%	6.9148%	0.9143%	0.0001%	1.4988%	3.3488%	0.0234%	0.0735%
	General Plant																		
369	Land & Land Rights		6,188,871																
	Production	100	3,728,853	3,838	3,728,014	13,184	1,053,745	130,677	938,814	109,134	731,382	127,489	307,713	281,889	6	9,437	16,373	278	2,178
	Transmission	101	147,107	138	148,888	400	34,442	2,996	39,552	3,723	30,318	5,338	19,248	11,881	0	82	80	2	100
	Distribution	102	2,323,211	878	2,322,533	8,310	896,423	78,202	590,216	71,434	328,845	60,628	160,848	21,242	3	34,835	77,769	545	1,708
380	Structures & Improvements		64,438,073																
	Production	100	38,783,352	37,825	38,725,527	137,133	10,861,871	1,357,128	9,767,381	1,134,261	7,801,565	1,326,028	3,188,148	3,031,611	63	98,098	107,786	2,887	22,620
	Transmission	101	1,528,823	1,440	1,527,483	4,153	357,883	31,143	400,883	38,894	315,088	55,458	200,053	121,404	0	848	832	25	1,040
	Distribution	102	24,145,788	7,048	24,138,760	88,388	9,316,782	823,187	6,134,278	742,457	3,428,170	525,128	1,669,842	220,778	34	359,867	808,591	5,682	17,761
381	Office Furniture & Equipment		48,857,788																
	Production	100	29,270,588	28,562	29,242,004	103,550	8,288,858	1,024,780	7,367,873	856,481	5,740,012	1,000,541	2,414,950	2,289,187	40	74,065	81,388	2,185	17,081
	Transmission	101	1,154,504	1,088	1,153,416	3,138	270,301	23,517	302,559	29,218	237,925	41,878	161,062	91,873	0	640	703	19	785
	Distribution	102	18,232,718	6,322	18,227,394	69,218	7,035,189	621,591	4,832,050	586,621	2,588,643	398,529	1,268,782	168,710	28	271,814	610,574	4,275	13,404
382	Transportation Equipment		18,872,412																
	Production	100	10,142,865	9,807	10,142,865	35,817	3,888,479	355,455	2,355,818	297,882	1,890,977	347,047	837,648	784,030	14	25,880	28,234	751	5,925
	Transmission	101	400,451	377	400,074	1,088	93,757	8,157	104,848	10,135	82,628	14,528	42,397	31,788	0	222	244	8	272
	Distribution	102	6,324,180	1,846	6,322,344	22,821	2,440,222	215,601	1,608,870	194,457	897,895	137,540	437,307	67,826	9	84,281	211,783	1,483	4,849
383	Stores Equipment		2,340,829																
	Production	100	1,408,155	1,374	1,408,781	4,882	387,848	49,300	354,455	41,204	278,142	48,134	118,179	110,129	2	3,583	3,916	104	822
	Transmission	101	55,541	52	55,489	151	13,004	1,131	14,558	1,406	11,446	2,015	7,287	4,410	0	31	34	1	38
	Distribution	102	877,143	256	876,887	3,137	338,450	28,983	222,840	26,870	124,535	19,078	60,653	8,020	1	13,076	28,374	206	645
384	Tools, Shop & Garage Equipment		8,830,485																
	Production	100	5,813,824	5,770	5,807,954	20,921	1,870,785	207,040	1,488,555	173,040	1,158,673	202,142	487,800	452,494	8	14,964	16,445	437	3,451
	Transmission	101	233,248	220	233,028	834	54,610	4,751	61,127	5,903	48,069	8,461	30,520	18,521	0	129	142	4	159
	Distribution	102	3,683,613	1,075	3,682,538	13,178	1,471,341	125,580	935,828	113,264	522,992	80,112	254,718	33,681	5	54,918	123,358	864	2,708
385	Laboratory Equipment		6,789,389																
	Production	100	3,783,443	3,692	3,779,751	13,385	1,068,842	132,481	852,354	110,788	741,940	128,328	312,151	285,896	5	8,574	10,521	280	2,208
	Transmission	101	148,228	141	148,087	405	34,838	3,040	39,108	3,777	30,763	5,413	19,528	11,849	0	83	91	2	101
	Distribution	102	2,358,717	889	2,356,028	8,430	909,352	80,344	588,728	72,485	334,602	51,254	162,963	21,548	3	35,134	78,921	553	1,733
386	Power Operated Equipment		1,394,358																
	Production	100	784,649	786	783,883	2,778	221,888	27,471	187,508	22,860	153,871	28,821	64,737	61,368	1	1,885	2,182	58	458
	Transmission	101	30,849	29	30,820	84	7,248	830	8,111	783	6,378	1,123	4,050	2,458	0	17	19	1	21
	Distribution	102	488,760	143	488,617	1,748	188,581	16,883	124,170	15,028	88,383	10,630	33,787	4,468	1	7,286	16,368	115	359
387	Communication Equipment		88,873,234																

COST OF SERVICE STUDY
(By FERC Account - 1996)

FERC ACCT	Description of Account	Total Utility	FERC JURIS	PA PUC JURIS	BA	BR	BN	SB/SM	SNM	SL	SN	L	NY/NE	AL	SE	SM	SH	TRAFFIC REQUIRE
Production	100	53,462,022	52,108	53,410,454	189,134	15,104,878	1,871,758	13,457,404	1,564,379	10,484,120	1,027,488	4,410,800	4,181,214	74	135,280	148,873	3,955	31,198
Transmission	101	2,108,688	1,808	2,106,712	5,727	493,704	42,953	852,923	53,387	434,688	78,480	275,914	167,441	1	1,169	1,285	34	1,434
Distribution	102	33,302,014	8,721	33,287,293	119,118	12,848,756	1,135,317	8,460,428	1,023,973	4,728,150	724,259	2,302,778	304,495	47	488,488	1,116,212	7,808	24,482
398 Misc Equipment		432,311																
Production	100	280,081	284	268,807	920	73,475	8,105	65,482	7,810	50,898	8,890	21,456	20,339	0	858	723	19	162
Transmission	101	10,257	10	10,247	28	2,401	209	2,888	280	2,114	372	814	0	6	8	0	7	
Distribution	102	181,993	47	181,948	579	82,506	5,623	41,155	4,881	22,999	3,523	11,202	1,481	0	2,415	5,426	38	118
399 Other Tangible Property		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total General Plant		245,243,958	178,263	245,087,695	888,413	78,502,548	8,418,484	82,096,715	7,288,785	43,177,988	7,252,556	19,287,828	12,840,281	335	1,748,522	3,681,210	32,555	157,808
Total General & Intangible Plant		289,344,483	207,959	289,138,524	1,022,215	82,618,118	9,928,963	73,156,954	8,600,833	50,941,338	8,658,732	22,755,888	15,148,237	395	2,050,587	4,118,010	38,408	185,847
Total Electric Plant In Service		4,201,155,890	3,171,113	4,197,984,578	14,852,750	1,310,138,591	141,180,648	1,083,934,906	123,864,388	754,423,874	127,560,733	344,118,088	238,286,025	5,493	28,606,547	52,187,974	507,880	2,885,781
Total Gen & Intangible Plant - Class Percentage		100%	0.0719%	99.9281%	0.3533%	32.0100%	3.4319%	25.2837%	2.9725%	17.6058%	2.9573%	7.8847%	5.2357%	0.0001%	0.7122%	1.4236%	0.0133%	0.0843%
Total Electric Plant In Service - Class Percentage		100%	0.0753%	99.9245%	0.3488%	31.1852%	3.3605%	25.3248%	2.9436%	17.9575%	3.0370%	8.1910%	5.6243%	0.0001%	0.6333%	1.2422%	0.0121%	0.0639%
General Plant Summary																		
Production		147,528,887	143,956	147,384,941	521,811	41,681,570	5,165,075	37,135,402	4,318,889	28,930,891	5,042,807	12,171,780	11,537,965	203	373,303	410,281	10,913	88,091
Transmission		5,818,806	5,481	5,813,425	15,804	1,382,388	118,528	1,524,952	147,265	1,199,182	211,072	781,380	462,050	2	3,226	3,548	84	3,857
Distribution		81,885,153	25,825	81,859,330	328,999	35,488,812	3,132,881	23,348,381	2,825,821	13,047,224	1,898,578	8,354,488	840,247	130	1,388,993	3,077,404	21,548	87,558
Total		245,243,958	178,263	245,087,695	888,413	78,502,548	8,418,484	82,096,715	7,288,785	43,177,988	7,252,556	19,287,828	12,840,281	335	1,748,522	3,681,210	32,555	157,808
Total General & Intangible Plant Summary																		
Production		174,057,889	169,842	173,888,158	615,763	48,178,879	6,093,875	43,813,205	5,093,141	34,133,087	5,849,739	14,360,547	13,812,757	240	440,431	484,035	12,876	101,572
Transmission		8,865,279	8,487	8,856,812	18,848	1,607,351	139,842	1,789,174	173,746	1,414,823	249,028	998,293	545,137	2	3,807	4,183	111	4,889
Distribution		108,421,304	21,849	108,399,555	287,805	41,834,889	3,898,245	27,544,578	3,333,745	15,393,418	2,357,858	7,487,148	881,347	154	1,618,349	3,830,782	25,422	78,707
Total		289,344,483	207,959	289,138,524	1,022,215	92,618,118	9,928,963	73,156,954	8,600,833	50,941,338	8,658,732	22,755,888	15,148,237	395	2,050,587	4,118,010	38,408	185,847
Total Electric Plant In Service Summary (Excluding General & Intangible Plant)																		
Production		2,368,388,721	2,309,085	2,364,089,638	8,371,583	668,592,339	82,849,039	595,660,714	69,243,608	484,055,188	60,889,437	185,238,257	185,071,708	3,258	5,987,865	6,580,681	175,045	1,380,915
Transmission		312,188,756	284,078	311,892,678	847,900	73,091,533	6,359,087	81,814,322	7,900,818	64,338,635	11,324,125	40,848,332	24,788,158	80	173,898	180,218	5,061	212,303
Distribution		1,233,225,730	359,882	1,232,865,738	4,411,052	475,845,588	42,042,558	313,302,818	37,919,335	175,080,817	26,820,438	85,275,511	11,275,823	1,748	18,384,888	41,288,955	288,166	808,818
Total		3,911,811,207	2,963,155	3,908,848,052	13,680,535	1,217,520,471	131,250,885	980,777,951	115,063,757	703,482,638	119,034,000	321,362,100	221,136,789	5,088	24,545,960	48,088,964	468,271	2,499,834
Total Electric Plant In Service Summary (Including General & Intangible Plant)																		
Production		2,540,458,720	2,478,928	2,537,877,792	8,987,346	717,759,219	88,942,914	638,473,918	74,338,747	488,188,283	66,839,176	209,588,804	188,884,465	3,489	6,428,298	7,064,716	187,920	1,482,487
Transmission		319,952,035	300,545	319,751,491	868,548	74,698,884	8,498,829	83,613,485	8,074,589	65,751,458	11,573,153	41,748,625	25,334,285	82	176,808	184,401	5,172	218,971
Distribution		1,341,948,834	391,841	1,341,256,793	4,788,858	512,681,488	45,718,884	340,847,482	41,253,880	189,454,333	28,178,404	92,772,857	12,787,288	1,801	20,091,345	44,928,882	314,587	888,312
Total		4,201,155,890	3,171,113	4,197,984,578	14,852,750	1,310,138,591	141,180,648	1,083,934,906	123,864,388	754,423,874	127,560,733	344,118,088	238,286,025	5,493	28,606,547	52,187,974	507,880	2,885,781

108 ACCUMULATED DEPRECIATION (P219)

Exhibit JAL-1B
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COST OF SERVICE STUDY
(By FERC Account - 1996)

FERC ACCT	Description of Account	Total MURR	FERC JURIS.	PAPUC JURIS.	GA	RI	NH	VT/VTM	VTM	QL	QLH	L	NYPS	AL	SE	EM	SH	TRAFFIC SIGNALS	
Intangible Plant																			
301	Organization	0																	
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
302	Franchises & Consents	0																	
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
303	Miscellaneous Intangible Plant	0																	
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Total Intangible Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Intangible Plant Summary																			
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Production Plant																			
A: Steam Prod Plant																			
310	Land & Land Rights	112	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
311	Structures & Improvements	112	(73,121,819)	(71,446)	(73,050,173)	(255,402)	(20,600,785)	(2,517,768)	(18,344,892)	(2,129,052)	(14,488,792)	(2,507,774)	(8,182,714)	(5,778,136)	(89)	(184,345)	(202,594)	(5,389)	(44,418)
312	Boiler Plant Equip	112	(218,157,215)	(213,159)	(217,844,058)	(781,888)	(81,183,805)	(7,511,724)	(54,433,353)	(8,351,895)	(43,221,119)	(7,491,908)	(18,475,867)	(17,238,880)	(298)	(548,990)	(604,436)	(18,078)	(132,521)
313	Engines and Engine Driven Motors	112	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
314	Turbogenerators	112	(84,854,044)	(83,388)	(84,790,878)	(226,524)	(18,182,851)	(2,233,065)	(18,182,014)	(1,888,329)	(12,848,827)	(2,224,230)	(5,492,528)	(5,124,825)	(88)	(183,502)	(179,688)	(4,780)	(39,398)
315	Accessory Electric Equip	112	(40,081,418)	(40,023)	(40,921,393)	(143,071)	(11,484,177)	(1,410,408)	(10,226,481)	(1,192,657)	(8,115,240)	(1,404,810)	(3,468,047)	(3,238,808)	(56)	(103,267)	(113,480)	(3,018)	(24,882)
316	Misc Power Plant Equip	112	(14,297,747)	(13,931)	(14,243,818)	(49,800)	(3,997,384)	(490,932)	(3,557,512)	(415,137)	(2,824,732)	(488,983)	(1,207,487)	(1,128,660)	(19)	(35,845)	(38,603)	(1,051)	(8,681)
	Total Steam Production Plant 311 - 318		(411,352,041)	(401,928)	(410,950,113)	(1,436,783)	(115,329,011)	(14,163,928)	(102,638,232)	(11,977,176)	(81,498,710)	(14,107,704)	(34,937,654)	(32,505,408)	(558)	(1,037,047)	(1,138,710)	(30,317)	(249,878)
B: Nuclear Production Plant																			
320	Land & Land Rights	113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
321	Structures & Improvements	113	(125,861,202)	(122,731)	(126,738,471)	(448,064)	(35,695,238)	(4,442,628)	(31,819,017)	(3,691,890)	(24,555,434)	(4,295,158)	(10,247,350)	(9,792,537)	(175)	(319,057)	(350,648)	(8,327)	(71,851)
322	Reactor Plant Equipment	113	(334,538,435)	(326,218)	(334,212,217)	(1,190,951)	(84,877,781)	(11,808,488)	(84,574,786)	(9,813,025)	(65,268,218)	(11,416,503)	(27,237,405)	(26,026,513)	(484)	(848,052)	(932,015)	(24,781)	(191,246)
323	Turbogenerators	113	(87,872,070)	(85,889)	(87,606,081)	(240,911)	(19,192,337)	(2,388,678)	(17,108,201)	(1,985,027)	(13,202,774)	(2,308,388)	(6,509,715)	(5,265,175)	(84)	(171,548)	(188,533)	(5,015)	(38,688)
324	Accessory Electric Equipment	113	(86,599,467)	(84,446)	(86,515,021)	(308,293)	(24,560,278)	(3,058,775)	(21,893,243)	(2,540,225)	(18,895,456)	(2,955,305)	(7,050,744)	(6,737,807)	(120)	(219,529)	(241,264)	(6,417)	(49,506)
325	Misc Power Plant Equipment	113	(36,502,357)	(35,595)	(36,466,762)	(128,948)	(10,352,359)	(1,288,455)	(9,228,174)	(1,070,725)	(7,121,585)	(1,245,684)	(2,971,844)	(2,840,038)	(51)	(82,533)	(101,695)	(2,705)	(20,857)
	Total Nuclear Production Plant 321 - 325		(651,173,531)	(634,978)	(650,538,553)	(2,318,166)	(184,677,992)	(22,985,023)	(164,623,422)	(19,100,892)	(127,043,506)	(22,222,034)	(53,017,158)	(50,664,071)	(903)	(1,650,720)	(1,814,152)	(48,255)	(372,258)
D: Other Production Plant																			
340	Land & Land Rights	114	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
341	Structures & Improvements	114	(3,288,817)	(3,205)	(3,288,614)	(11,888)	(941,550)	(118,400)	(840,373)	(97,070)	(633,895)	(111,822)	(259,238)	(252,760)	(5)	(8,376)	(9,206)	(245)	(1,787)
342	Fuel Holders, Products and Accessories	114	(1,583,911)	(1,542)	(1,582,369)	(5,724)	(453,317)	(57,905)	(404,605)	(48,735)	(305,194)	(53,838)	(124,813)	(121,694)	(2)	(4,033)	(4,432)	(118)	(860)
343	Pneum Movers	114	(223,588)	(218)	(223,350)	(868)	(63,895)	(8,948)	(57,110)	(6,587)	(43,078)	(7,598)	(17,617)	(17,177)	(0)	(568)	(628)	(17)	(121)
344	Generators	114	(10,858,250)	(10,568)	(10,845,681)	(38,231)	(3,107,072)	(380,715)	(2,773,183)	(320,326)	(2,091,825)	(369,007)	(855,475)	(834,088)	(15)	(27,841)	(30,378)	(808)	(5,696)
345	Accessory Electric Equipment	114	(1,918,779)	(1,859)	(1,917,910)	(6,937)	(549,443)	(69,023)	(480,401)	(58,845)	(369,811)	(65,264)	(151,279)	(147,489)	(3)	(4,888)	(5,372)	(143)	(1,043)

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total Utility	FERC JURIS	PA PUC JURIS	BA	BE	BH	BB/OM	QMH	GL	GLH	L	HYPE	AL	EE	EM	EH	TRAFFIC SIGNALS	
346	Misc Power Plant Equipment	114	(1,128,465)	(1,099)	(1,127,388)	(4,078)	(322,974)	(40,614)	(288,288)	(33,297)	(217,441)	(58,358)	(88,925)	(86,703)	(2)	(2,873)	(3,158)	(84)	(813)
	Total Other Production Plant 341 - 346		(19,001,610)	(18,489)	(18,983,311)	(88,887)	(6,438,341)	(883,873)	(4,853,849)	(560,870)	(3,861,344)	(645,878)	(1,497,347)	(1,459,831)	(27)	(48,381)	(53,171)	(1,414)	(10,319)
	Total Production Plant		(1,081,627,342)	(1,055,408)	(1,080,471,978)	(3,823,817)	(205,445,345)	(37,832,824)	(272,118,603)	(31,838,732)	(212,201,660)	(36,976,815)	(89,352,158)	(84,629,410)	(1,488)	(2,738,148)	(3,007,034)	(79,987)	(831,464)
Transmission Plant																			
350	Total Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
352	Structures and Improvements	118	(1,980,150)	(1,881)	(1,958,289)	(6,387)	(482,828)	(40,249)	(517,048)	(50,089)	(407,214)	(71,875)	(243,504)	(158,901)	(1)	(1,098)	(1,204)	(32)	(1,344)
353	Station Equipment	118	(53,283,616)	(50,807)	(53,243,009)	(145,813)	(12,878,174)	(1,094,322)	(14,058,278)	(1,359,835)	(11,071,681)	(1,948,748)	(6,820,521)	(4,285,918)	(18)	(29,788)	(32,734)	(871)	(38,535)
354	Towers & Fibres	117	(23,346,334)	(21,388)	(23,327,846)	(81,888)	(8,315,955)	(482,487)	(9,982,635)	(874,827)	(4,879,210)	(823,605)	(3,802,591)	(1,802,918)	(7)	(12,690)	(13,835)	(388)	(15,441)
355	Poles & Fictures	117	(1,668,716)	(1,627)	(1,665,188)	(4,402)	(379,482)	(35,014)	(425,823)	(41,018)	(334,010)	(58,780)	(257,159)	(129,885)	(0)	(899)	(888)	(26)	(1,102)
356	Ovhd Conductor & Devices	117	(21,424,387)	(19,825)	(21,404,742)	(68,694)	(4,877,897)	(424,358)	(5,471,083)	(527,254)	(4,283,447)	(755,705)	(3,305,588)	(1,854,282)	(8)	(11,552)	(12,894)	(338)	(14,168)
357	Underground Conduit	1	(8,072,593)	(7,878)	(8,084,716)	(22,713)	(1,857,934)	(170,344)	(2,188,328)	(211,643)	(1,723,413)	(303,344)	(807,402)	(884,038)	(2)	(4,837)	(5,085)	(138)	(6,887)
358	Underground Conductors and Devices	1	(7,918,705)	(7,727)	(7,910,978)	(22,280)	(1,920,810)	(187,098)	(2,148,612)	(207,808)	(1,690,558)	(297,581)	(782,811)	(851,378)	(2)	(4,548)	(4,998)	(133)	(5,679)
359	Roads & Traffs	1	(5,122)	(5)	(5,117)	(14)	(1,242)	(108)	(1,388)	(134)	(1,093)	(182)	(512)	(0)	(3)	(3)	(0)	(4)	
	Total Transmission Plant		(117,690,602)	(110,818)	(117,679,883)	(318,941)	(27,493,701)	(2,381,898)	(30,770,993)	(2,871,827)	(24,200,508)	(4,259,818)	(16,828,288)	(9,324,551)	(34)	(85,112)	(71,651)	(1,904)	(78,859)
Distribution Plant																			
360	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
361	Structures & Improvement	118	(13,307,734)	(8,874)	(13,301,080)	(45,809)	(3,631,344)	(471,528)	(3,458,748)	(398,877)	(2,393,048)	(308,821)	(2,261,932)	(253,638)	(18)	(35,823)	(44,335)	(918)	(8,428)
362	Station Equipment	118	(85,204,682)	(42,733)	(85,161,859)	(293,838)	(23,750,178)	(3,019,007)	(22,145,094)	(2,654,603)	(15,321,819)	(1,975,885)	(14,418,304)	(1,623,956)	(113)	(228,078)	(283,880)	(5,882)	(41,145)
363	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
364	Poles, Towers, Fictures'	118	(88,699,858)	(86,888,343)	(88,688,343)	(318,154)	(35,828,787)	(3,017,028)	(16,828,647)	(1,719,308)	(3,353,814)	(534,522)	(830,721)	(0)	(157)	(1,705,092)	(3,819,119)	(38,428)	(85,586)
365	Ovhd Conductor & Devices	119	(60,090,427)	(58,018,433)	(60,018,433)	(264,927)	(32,278,533)	(2,718,072)	(14,080,824)	(1,548,943)	(3,021,576)	(481,556)	(748,406)	(0)	(141)	(1,538,135)	(3,260,502)	(32,818)	(88,098)
366	Underground Conduit	120	(16,840,062)	(16,822,870)	(16,835,870)	(34,707)	(3,050,884)	(352,443)	(5,080,785)	(783,581)	(4,612,212)	(764,106)	(1,021,323)	(0)	(14)	(47,143)	(80,788)	(1,557)	(13,308)
367	Underground Lines	120	(34,037,465)	(34,028,387)	(34,028,387)	(74,580)	(8,555,864)	(757,335)	(10,874,880)	(1,705,218)	(9,910,803)	(1,641,924)	(2,194,637)	(0)	(31)	(101,301)	(195,044)	(3,348)	(13,554)
368	Line Transformers	121	(51,528,807)	(51,528,807)	(51,518,853)	(180,940)	(20,641,280)	(1,342,702)	(11,104,784)	(1,881,888)	(10,523,888)	(1,841,856)	(2,121,785)	(1,238,328)	(58)	(80,679)	(767,740)	(11,352)	(32,317)
369	Services	122	(19,868,087)	(19,868,087)	(19,865,898)	(82,448)	(15,371,384)	(724,884)	(2,235,438)	(208,279)	(848,222)	(101,838)	(242,891)	(224,388)	(3)	(6,085)	(6,688)	(177)	(1,240)
370	Meters	40	(25,120,858)	(25,120,858)	(25,118,705)	(80,868)	(10,690,502)	(480,828)	(11,548,776)	(803,415)	(1,115,250)	(169,858)	(167,304)	(61,308)	(0)	(0)	(0)	(0)	(0)
371	Installabons on Cust Premises	20	37,544	37,544	37,544	0	0	0	4,534	0	13,734	0	2,203	0	0	0	0	0	
372	Leased Property on Customer Premise	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
373	Street Lights & Signal Systems	18	(14,747,084)	(14,747,084)	(14,747,084)	(1,384,487)	(151,208,898)	(12,893,821)	(98,134,088)	(11,412,088)	(50,884,898)	(7,850,365)	(23,995,698)	(3,387,540)	(534)	(4,421,823)	(10,325,211)	(92,481)	(282,652)
	Total Distribution Plant		(388,407,988)	(388,407,988)	(388,302,753)	(1,384,487)	(151,208,898)	(12,893,821)	(98,134,088)	(11,412,088)	(50,884,898)	(7,850,365)	(23,995,698)	(3,387,540)	(534)	(4,421,823)	(10,325,211)	(92,481)	(282,652)
General Plant																			
389	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
390	Structures & Improvements	100	(13,588,593)	(13,259)	(13,575,334)	(48,072)	(3,839,206)	(475,745)	(3,470,489)	(387,818)	(2,684,748)	(484,492)	(1,121,118)	(1,082,739)	(18)	(34,384)	(37,788)	(1,005)	(7,930)
	Production	101	(535,868)	(535,868)	(535,868)	(1,458)	(125,485)	(10,917)	(140,460)	(13,584)	(110,454)	(19,441)	(70,128)	(42,558)	(0)	(287)	(327)	(8)	(364)
	Distribution	102	(8,484,372)	(8,484,372)	(8,481,901)	(30,278)	(3,268,022)	(288,563)	(2,150,587)	(280,263)	(1,201,754)	(184,085)	(685,297)	(77,393)	(12)	(128,187)	(283,454)	(1,985)	(8,223)
391	Office Furniture & Equipment	100	(12,202,513)	(11,907)	(12,190,606)	(43,189)	(3,447,585)	(427,217)	(3,071,589)	(357,080)	(2,382,936)	(417,112)	(1,008,761)	(854,336)	(17)	(30,877)	(33,934)	(903)	(7,121)
	Production	101	(481,297)	(453)	(480,844)	(1,307)	(112,685)	(8,804)	(126,133)	(12,181)	(88,188)	(17,458)	(38,217)	(283)	(0)	(267)	(293)	(8)	(327)
	Distribution	102	(7,800,979)	(7,800,979)	(7,800,979)	(27,187)	(2,832,878)	(258,129)	(1,931,041)	(233,716)	(1,079,171)	(165,308)	(525,595)	(69,499)	(11)	(113,318)	(254,540)	(1,782)	(5,588)
392	Transportation Equipment	100	(5,721,685)	(5,583)	(5,716,102)	(20,242)	(1,616,557)	(200,320)	(1,440,240)	(187,423)	(1,122,033)	(185,582)	(472,064)	(447,482)	(8)	(14,478)	(15,811)	(423)	(3,339)

COST OF SERVICE STUDY
(By FERC Account - 1996)

FERC ACCT	Description of Account	Total 1996	FERC JURIS.	PA PUC JURIS.	RA	RR	RM	REGM	RMH	SL	SLH	L	TYPE	AL	EE	EM	EH	TRAFFIC SIGNALS
	Transmission	101 (226,877)	(213)	(226,464)	(613)	(52,937)	(4,697)	(50,143)	(5,711)	(46,508)	(8,186)	(20,520)	(17,920)	(8)	(126)	(138)	(4)	(153)
	Distribution	102 (3,664,053)	(1,040)	(3,563,013)	(12,748)	(1,376,208)	(121,604)	(805,453)	(109,899)	(506,017)	(77,512)	(248,448)	(32,588)	(8)	(53,133)	(119,352)	(936)	(2,820)
393	Stores Equipment																	
	Production	100 (529,931)	(517)	(529,414)	(1,875)	(149,722)	(18,563)	(133,392)	(15,606)	(103,920)	(18,114)	(43,722)	(41,445)	(1)	(1,341)	(1,474)	(38)	(309)
	Transmission	101 (20,902)	(20)	(20,882)	(57)	(4,894)	(429)	(5,478)	(526)	(4,308)	(758)	(2,755)	(1,880)	(0)	(112)	(13)	(0)	(14)
	Distribution	102 (330,886)	(98)	(330,000)	(1,181)	(127,389)	(11,253)	(83,861)	(10,150)	(48,886)	(7,178)	(22,928)	(3,018)	(0)	(4,921)	(11,054)	(77)	(243)
394	Tool, Shop & Garage Equipment																	
	Production	100 (2,126,983)	(2,075)	(2,124,019)	(7,521)	(800,888)	(74,438)	(535,173)	(82,212)	(416,931)	(72,875)	(175,412)	(188,278)	(3)	(5,380)	(5,912)	(157)	(1,341)
	Transmission	101 (83,858)	(78)	(83,778)	(228)	(19,634)	(1,708)	(21,877)	(2,122)	(17,282)	(3,042)	(10,873)	(8,658)	(0)	(46)	(51)	(1)	(57)
	Distribution	102 (1,324,348)	(387)	(1,323,983)	(4,737)	(511,007)	(46,149)	(338,455)	(40,721)	(188,028)	(28,802)	(81,577)	(12,108)	(3)	(19,743)	(44,350)	(311)	(874)
395	Laboratory Equipment																	
	Production	100 (1,332,738)	(1,301)	(1,332,437)	(4,718)	(378,823)	(46,895)	(335,723)	(39,027)	(281,648)	(45,591)	(110,039)	(104,309)	(2)	(3,375)	(3,709)	(98)	(778)
	Transmission	101 (52,806)	(50)	(52,658)	(143)	(12,317)	(1,072)	(13,789)	(1,331)	(10,841)	(1,908)	(6,883)	(4,177)	(0)	(28)	(32)	(1)	(38)
	Distribution	102 (830,789)	(243)	(830,548)	(2,972)	(320,664)	(28,323)	(211,085)	(25,545)	(117,954)	(18,068)	(57,448)	(7,596)	(1)	(12,385)	(27,821)	(195)	(611)
396	Power Operated Equipment																	
	Production	100 (514,404)	(502)	(513,902)	(1,820)	(145,335)	(18,010)	(129,484)	(15,052)	(100,878)	(17,584)	(42,441)	(40,231)	(1)	(1,302)	(1,430)	(38)	(360)
	Transmission	101 (20,289)	(18)	(20,270)	(55)	(4,750)	(413)	(5,317)	(513)	(4,181)	(739)	(2,855)	(1,811)	(0)	(11)	(12)	(0)	(14)
	Distribution	102 (320,424)	(84)	(320,330)	(1,148)	(123,637)	(10,924)	(81,404)	(9,852)	(45,493)	(8,969)	(27,167)	(2,930)	(0)	(4,777)	(10,730)	(75)	(238)
397	Communication Equipment																	
	Production	100 (29,833,869)	(29,111)	(29,804,858)	(105,543)	(8,429,038)	(1,044,505)	(7,608,691)	(872,877)	(5,850,497)	(1,019,800)	(2,461,433)	(2,333,260)	(41)	(25,491)	(82,955)	(2,207)	(17,410)
	Transmission	101 (1,178,728)	(1,108)	(1,175,618)	(3,188)	(275,504)	(23,869)	(308,363)	(29,185)	(242,504)	(42,684)	(153,870)	(83,438)	(0)	(652)	(717)	(19)	(800)
	Distribution	102 (18,583,661)	(5,426)	(18,578,230)	(88,471)	(7,170,603)	(833,548)	(4,721,208)	(571,412)	(2,638,469)	(404,161)	(1,285,029)	(169,819)	(28)	(27,046)	(82,327)	(4,357)	(13,882)
398	Misc Equipment																	
	Production	100 (101,842)	(89)	(101,743)	(360)	(29,774)	(3,568)	(25,635)	(2,880)	(19,971)	(3,481)	(8,402)	(7,965)	(0)	(268)	(283)	(8)	(59)
	Transmission	101 (4,017)	(4)	(4,013)	(11)	(840)	(82)	(1,053)	(102)	(828)	(148)	(528)	(319)	(0)	(2)	(2)	(0)	(3)
	Distribution	102 (83,437)	(18)	(83,418)	(227)	(24,477)	(2,163)	(18,118)	(1,851)	(8,001)	(1,360)	(4,387)	(580)	(0)	(948)	(2,124)	(15)	(47)
	Subtotal	(109,838,289)	(78,798)	(109,557,471)	(387,330)	(35,094,551)	(3,782,588)	(27,720,092)	(3,258,888)	(19,302,314)	(3,742,254)	(8,622,530)	(5,740,237)	(150)	(780,782)	(1,560,745)	(14,554)	(70,458)
399	Other Tangible Property																	
	Production	100 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	101 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	102 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total General Plant	(109,636,289)	(78,798)	(109,557,471)	(387,330)	(35,094,551)	(3,782,588)	(27,720,092)	(3,258,888)	(19,302,314)	(3,742,254)	(8,622,530)	(5,740,237)	(150)	(780,782)	(1,560,745)	(14,554)	(70,458)
	Total Accumulated Depreciation	(1,695,262,221)	(1,350,037)	(1,693,912,184)	(5,894,355)	(519,332,492)	(56,881,232)	(426,740,785)	(49,281,615)	(308,599,281)	(52,327,874)	(137,598,074)	(103,061,737)	(2,207)	(11,724,031)	(23,222,574)	(188,925)	(1,065,423)
	NET PLANT IN SERVICE	2,505,893,468	1,821,076	2,504,072,382	8,758,395	780,807,098	84,289,418	637,194,121	74,382,174	447,834,694	75,262,879	296,519,415	125,224,288	3,288	14,882,517	28,865,388	318,764	1,620,359
	Total Accumulated Depr. - Class Percentage	100%	0.0796%	99.9204%	0.3477%	30.6343%	3.3533%	25.1726%	2.9070%	18.0851%	3.0867%	8.1167%	8.0794%	0.0001%	0.6916%	1.3899%	0.0111%	0.0628%
	NET PLANT IN SERVICE - Class Percentage	100%	0.0727%	99.9273%	0.3495%	31.5579%	3.3640%	25.4278%	2.9683%	17.8713%	3.0034%	8.2413%	5.3164%	0.0001%	0.5939%	1.1559%	0.0127%	0.0647%

Total General & Intangible Plant Accumulated Depreciation Summary																		
Production	(65,957,768)	(64,355)	(65,898,413)	(233,320)	(18,933,738)	(2,309,046)	(16,801,375)	(1,929,855)	(12,933,460)	(2,254,431)	(5,441,392)	(5,159,045)	(91)	(168,885)	(183,407)	(4,878)	(38,887)	
Transmission	(2,601,341)	(2,450)	(2,598,890)	(7,085)	(609,046)	(52,888)	(681,729)	(65,835)	(536,094)	(84,360)	(340,375)	(208,559)	(1)	(1,442)	(1,585)	(42)	(1,749)	
Distribution	(41,982,180)	(11,892)	(41,970,188)	(148,944)	(15,851,768)	(1,400,564)	(10,436,987)	(1,283,189)	(5,922,759)	(893,463)	(2,940,763)	(375,832)	(58)	(812,455)	(1,375,763)	(8,833)	(30,202)	
Total	(109,636,289)	(78,798)	(109,557,471)	(387,330)	(35,094,551)	(3,782,588)	(27,720,092)	(3,258,888)	(19,302,314)	(3,742,254)	(8,622,530)	(5,740,237)	(150)	(780,782)	(1,560,745)	(14,554)	(70,458)	

Total Plant Accumulated Depreciation Summary (including General & Intangible Plant)

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total Utility	FERC JURIS.	PAPUC JURIS.	BA	BE	BH	GM/SM	GMH	QL	QLH	L	MVPE	AL	RE	RM	RH	TRAFFIC SIGNALS	
	Production	(1,147,480,150)	(1,118,781)	(1,148,380,389)	(4,056,837)	(324,078,084)	(40,141,870)	(288,718,978)	(33,868,587)	(225,135,020)	(38,230,048)	(84,793,551)	(89,787,455)	(1,578)	(2,903,033)	(3,190,441)	(84,885)	(870,841)	
	Transmission	(120,291,843)	(113,089)	(120,178,874)	(328,006)	(28,102,747)	(2,444,887)	(31,482,722)	(3,037,781)	(24,738,802)	(4,353,878)	(18,969,881)	(9,531,110)	(35)	(86,554)	(73,130)	(1,948)	(81,628)	
	Distribution	(427,490,128)	(417,287)	(427,372,921)	(1,511,411)	(187,150,882)	(14,284,375)	(108,871,988)	(12,875,288)	(58,717,853)	(8,753,828)	(28,938,482)	(3,743,172)	(682)	(8,754,443)	(19,958,987)	(192,113)	(312,854)	
	Total	(1,695,262,221)	(1,350,977)	(1,693,932,184)	(5,896,355)	(619,332,482)	(58,861,232)	(428,740,788)	(49,281,615)	(308,589,281)	(67,327,854)	(137,599,674)	(103,061,737)	(2,207)	(11,724,031)	(23,222,574)	(188,925)	(1,065,423)	
	Total Net Electric Plant in Service Summary (Excluding General & Intangible Plant)																		
	Production	1,284,871,339	1,253,879	1,283,817,680	4,547,987	383,136,985	45,016,215	323,645,111	37,604,874	251,853,828	43,813,822	105,888,088	100,442,287	1,771	3,251,717	3,573,847	95,058	748,481	
	Transmission	184,498,154	183,459	184,312,695	528,959	45,597,832	3,887,089	51,043,329	4,928,889	40,138,127	7,064,508	25,219,045	15,484,807	58	107,887	118,887	3,157	132,444	
	Distribution	846,817,282	254,777	846,582,886	3,946,685	324,647,703	28,148,737	217,188,818	28,507,287	124,295,818	18,870,023	81,278,812	7,808,383	1,219	10,243,908	22,714,820	189,884	823,963	
	Total	2,320,185,255	1,691,916	2,324,493,340	8,123,611	733,282,530	78,132,041	591,767,258	69,041,030	418,195,671	69,948,400	192,384,858	123,816,288	3,041	13,602,712	28,407,134	294,899	1,504,888	
	Total Net Electric Plant in Service Summary (Including General & Intangible Plant)																		
	Production	1,382,878,589	1,359,186	1,381,817,403	4,930,409	393,880,135	48,801,044	350,766,941	40,788,160	273,053,263	47,609,130	114,805,253	108,897,009	1,820	3,525,283	3,874,275	103,055	811,546	
	Transmission	188,780,093	187,476	188,572,617	540,539	48,596,138	4,053,843	62,180,773	5,038,801	41,014,858	7,219,174	26,776,884	15,803,185	58	110,351	121,265	3,226	135,344	
	Distribution	814,158,808	274,434	813,882,312	3,287,448	350,430,828	31,444,429	234,278,497	28,517,814	133,788,575	20,434,575	85,938,185	8,524,094	1,309	11,248,902	24,868,860	212,473	823,488	
	Total	2,505,893,489	1,821,078	2,504,672,392	9,758,395	790,807,099	84,293,418	637,164,121	74,382,774	447,834,894	75,262,879	206,519,413	133,224,288	3,288	14,882,517	28,895,389	318,754	1,820,358	
	Additions To Plant																		
105	Add: Land/Plant Held For Future Use (P214)																		
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
106	GWIP - Construction Work In Progress (P216.1)																		
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Total		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Deductions To Plant																		
	Less: Accum. Deferred Income Taxes (P273-277)																		
	Intangible Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Production Plant	100	(240,024,770)	(234,211)	(239,790,559)	(848,133)	(87,814,574)	(8,403,413)	(80,418,105)	(7,023,407)	(47,069,303)	(8,204,848)	(19,803,095)	(18,771,887)	(331)	(607,352)	(667,481)	(17,755)	
	Transmission Plant	101	(23,087,876)	(21,749)	(23,066,127)	(82,707)	(5,405,509)	(470,288)	(8,058,608)	(584,309)	(4,758,037)	(837,479)	(3,020,852)	(1,833,290)	(7)	(12,802)	(14,058)	(374)	
	Distribution Plant	102	(88,280,980)	(28,894)	(88,261,876)	(355,148)	(38,311,835)	(3,384,981)	(25,225,023)	(3,053,007)	(14,087,123)	(2,158,389)	(6,865,805)	(807,861)	(141)	(1,480,235)	(3,325,040)	(23,282)	
	General Plant		(25,765,888)																
	Production	100	(15,489,733)	(15,124)	(15,484,609)	(54,833)	(4,378,164)	(542,655)	(3,801,533)	(453,540)	(3,038,526)	(528,820)	(1,278,786)	(1,212,208)	(21)	(38,220)	(43,103)	(1,147)	
	Transmission	101	(811,348)	(576)	(810,772)	(1,660)	(143,133)	(12,453)	(180,215)	(15,472)	(175,989)	(22,179)	(79,992)	(48,544)	(0)	(339)	(372)	(10)	
	Distribution	102	(8,554,827)	(7,818)	(8,552,009)	(24,534)	(3,725,368)	(329,148)	(2,452,824)	(288,882)	(1,370,122)	(299,879)	(882,815)	(88,278)	(14)	(143,935)	(323,318)	(2,264)	
	Total	(388,168,514)	(303,463)	(387,866,051)	(1,358,015)	(118,779,682)	(13,142,937)	(88,208,305)	(11,428,601)	(70,460,752)	(11,963,498)	(31,716,255)	(22,862,077)	(513)	(2,283,882)	(4,373,383)	(44,831)	(245,321)	

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total UNIV	FERC JURIS	PA PUC JURIS	BA	RR	RH	ORIGM	GMN	QL	QLH	L	HYPR	AL	RE	EM	EH	TRAFFIC SIGNALS
	Rate Base Prior To Extraordinary Adjustment	2,117,723,954	1,617,613	2,118,206,341	7,400,380	671,027,418	71,156,478	538,085,816	62,856,173	377,373,842	83,299,382	174,802,157	110,382,211	2,773	12,688,635	24,582,018	273,823	1,376,037
Total Accumulated Deferred Income Taxes Summary																		
	Production	(255,624,603)	(249,336)	(255,276,187)	(903,868)	(72,183,738)	(8,948,048)	(64,319,838)	(7,478,947)	(50,108,830)	(8,734,468)	(21,081,890)	(19,884,103)	(352)	(646,672)	(710,684)	(18,901)	(149,112)
	Transmission	(23,899,224)	(22,324)	(23,876,900)	(84,367)	(5,548,642)	(482,741)	(8,210,821)	(598,778)	(4,884,026)	(858,655)	(3,100,044)	(1,681,835)	(7)	(13,141)	(14,440)	(384)	(18,117)
	Distribution	(108,845,782)	(31,892)	(108,813,890)	(389,682)	(42,037,302)	(3,714,128)	(27,877,847)	(3,348,876)	(16,487,888)	(2,388,378)	(7,533,420)	(986,138)	(154)	(1,824,170)	(3,648,358)	(25,545)	(80,923)
	Total	(388,169,614)	(303,483)	(387,886,061)	(1,358,015)	(118,776,682)	(13,142,937)	(98,208,305)	(11,426,601)	(70,486,762)	(11,983,498)	(31,718,265)	(22,892,077)	(513)	(2,283,882)	(4,373,393)	(44,831)	(245,321)
Net Rate Base Prior To Extraordinary Adjustment Summary																		
	Production	1,137,452,068	1,109,831	1,136,342,238	4,028,443	371,486,387	39,854,878	288,437,303	33,281,213	222,944,433	38,874,682	93,723,383	88,812,808	1,668	2,878,691	3,183,691	84,153	682,434
	Transmission	176,080,889	185,151	174,895,718	478,172	41,847,498	3,671,202	45,949,853	4,437,022	38,130,830	8,359,619	22,878,020	13,821,351	51	87,211	108,824	2,842	119,227
	Distribution	895,211,819	242,821	894,868,988	2,897,165	308,483,824	27,139,390	208,588,289	25,241,839	118,788,818	18,085,201	58,492,719	7,527,832	1,152	8,822,732	21,321,501	189,828	593,378
	Total	2,117,723,954	1,617,613	2,118,206,341	7,400,380	671,027,418	71,156,478	538,085,816	62,856,173	377,373,842	83,299,382	174,802,157	110,382,211	2,773	12,688,635	24,582,018	273,823	1,376,037

Adjustments To Rate Base For Rate Making

Add:																		
Regulatory Assets		344,788,483																
Production	100	455,273,723	444,247	454,829,476	1,610,817	128,828,188	15,939,406	114,689,737	13,321,844	88,280,023	16,562,387	37,562,078	35,606,124	827	1,152,011	1,268,063	33,677	285,676
Transmission	101	32,870,171	30,775	32,839,396	88,732	7,848,888	865,475	8,561,823	828,818	8,732,793	1,185,083	4,274,755	2,694,172	8	18,115	19,908	530	22,217
Distribution	102	56,844,591	16,594	56,827,997	203,324	21,933,783	1,937,919	14,441,457	1,747,863	8,070,678	1,238,267	3,930,709	519,755	81	847,442	1,803,603	13,328	41,780
Philips		78,399,252																
Production	100	78,399,252	78,500	78,322,752	277,352	22,160,284	2,744,805	19,734,358	2,294,054	15,374,238	2,679,883	6,468,282	6,131,462	108	198,378	218,019	5,789	45,750
Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bunok Island		28,758,383																
Production	100	28,758,383	28,082	28,730,501	101,739	8,125,202	1,006,856	7,238,984	841,609	5,639,608	983,040	2,372,707	2,248,155	40	22,770	79,914	2,127	16,782
Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wisniew		15,294,914																
Production	100	15,294,914	14,924	15,279,990	64,109	4,321,788	635,484	3,849,878	447,547	2,899,361	522,818	1,261,897	1,186,187	21	38,702	42,533	1,131	8926
Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Taxes		(485,985,645)																
Production	100	(383,558,497)	(374,268)	(383,184,228)	(1,358,911)	(108,387,385)	(13,428,613)	(98,547,858)	(11,223,372)	(75,218,534)	(13,110,990)	(31,645,256)	(28,897,407)	(528)	(970,545)	(1,066,632)	(28,372)	(223,828)
Transmission	101	(37,049,551)	(34,900)	(37,014,651)	(100,827)	(8,874,322)	(754,681)	(9,709,521)	(937,648)	(7,635,312)	(1,343,919)	(4,847,779)	(2,841,916)	(11)	(20,543)	(22,575)	(601)	(25,188)
Distribution	102	(65,377,597)	(19,084)	(65,358,513)	(233,845)	(25,226,288)	(2,228,823)	(18,809,280)	(2,010,236)	(9,282,175)	(1,421,845)	(4,520,752)	(587,776)	(93)	(974,653)	(2,189,354)	(15,330)	(48,063)
Working Capital		89,840,800																
Production	100	83,590,000	62,050	83,527,850	224,882	17,868,182	2,226,324	16,006,828	1,860,718	12,470,117	2,173,668	5,246,453	4,973,257	88	160,806	178,838	4,704	37,108
Transmission	101	1,240,000	1,168	1,238,832	3,368	280,318	25,258	324,855	31,382	255,544	44,979	182,249	88,482	0	888	756	20	843
Distribution	102	5,110,000	1,492	5,108,508	18,278	1,971,720	174,208	1,288,203	167,123	725,507	111,133	353,348	48,723	7	76,180	171,123	1,188	3,757
Total Net Adjustment To Rate Base		251,195,569	247,558	250,948,010	891,087	70,788,958	8,843,618	63,189,481	7,357,588	49,413,847	8,622,492	20,618,690	19,978,187	348	598,452	600,253	18,713	145,764

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total VOLUME	FERC JURIS.	PA PUC JURIS.	RA	RE	RH	REGM	RNH	RL	QLH	L	HYPR	AL	RE	RM	RH	TRAFFIC SIGNALS	
<i>Rate Base Adjusted For Ratemaking</i>		2,368,918,523	1,765,172	2,367,154,351	8,291,477	741,798,375	80,000,097	602,176,298	70,313,771	428,787,769	71,921,974	185,420,848	130,240,408	3,123	13,198,087	25,192,269	292,138	1,520,801	
Extraordinary Adjustment Summary																			
	Production	257,757,955	251,516	257,508,440	911,068	72,824,758	8,024,281	64,881,833	7,542,300	50,548,814	8,810,813	21,268,180	20,158,777	355	652,223	716,795	19,067	150,415	
	Transmission	(8,139,380)	(7,957)	(3,136,423)	(9,527)	(735,015)	(83,948)	(822,733)	(78,451)	(846,875)	(113,878)	(410,775)	(249,282)	(1)	(1,741)	(1,813)	(51)	(2,135)	
	Distribution	(3,422,008)	(999)	(3,422,007)	(12,244)	(1,320,785)	(118,686)	(888,820)	(105,261)	(485,891)	(74,444)	(238,885)	(31,288)	(5)	(51,030)	(114,828)	(803)	(2,519)	
	Total	251,196,568	247,559	250,948,010	891,097	70,768,958	8,945,819	63,189,481	7,367,698	49,413,847	8,622,492	20,818,690	19,878,197	349	599,452	600,253	18,213	145,764	
Net Rate Base After Extraordinary Adjustment Summary																			
	Production	1,395,210,021	1,381,548	1,393,948,878	4,938,311	384,311,158	48,979,239	351,319,138	40,833,513	273,491,247	47,885,475	114,989,523	109,071,883	1,923	3,530,915	3,980,488	103,220	812,848	
	Transmission	171,921,499	182,194	171,758,285	487,848	40,312,480	3,607,284	45,127,220	4,357,570	35,483,854	6,245,642	22,285,245	13,872,068	50	95,470	104,812	2,781	117,092	
	Distribution	891,289,013	241,832	891,346,381	2,389,521	307,172,739	27,813,804	295,728,940	25,122,888	117,812,888	17,890,757	58,188,889	7,489,657	1,159	9,571,192	21,296,971	188,125	980,859	
	Total	2,368,918,523	1,765,172	2,367,154,351	8,291,477	741,798,375	80,000,097	602,176,298	70,313,771	428,787,769	71,921,974	185,420,848	130,240,408	3,123	13,198,087	25,192,269	292,138	1,520,801	
Adjusted Return for Ratemaking @ 8.75%																			
	Production Plant	134,078,883	130,875	133,948,858	474,572	37,893,302	4,697,295	33,761,789	3,824,101	28,282,509	4,582,574	11,050,493	10,481,789	185	338,321	372,815	9,919	78,115	
	Transmission Plant	16,521,855	16,587	16,508,068	44,941	3,874,028	337,047	4,338,728	418,763	3,408,988	600,208	2,138,690	1,313,886	5	8,175	10,082	268	11,253	
	Distribution Plant	77,051,828	23,221	77,028,607	277,289	28,519,300	2,653,887	18,779,551	2,414,280	11,321,199	1,728,912	5,589,780	720,429	110	919,841	2,037,880	17,887	58,282	
	Total	227,653,166	169,633	227,483,533	798,811	71,288,632	7,688,029	57,869,046	6,757,153	41,014,307	6,911,692	18,779,943	12,516,103	300	1,268,338	2,420,977	28,074	146,148	
POWER PRODUCTION EXPENSE (P320)																			
A: Steam Power Generation Operation																			
500	Supervision & Engineering	100	8,004,847	5,859	5,998,788	21,243	1,686,502	210,226	1,511,468	175,703	1,177,522	205,254	495,410	469,612	8	15,194	16,698	444	3,504
501	Fuel	12	158,405,183	155,918	158,249,247	448,395	38,737,394	4,020,907	33,827,232	4,212,851	35,749,354	5,831,857	18,407,418	14,278,023	165	372,351	409,169	10,891	151,441
502	Steam Expense	100	8,590,516	8,382	8,582,133	30,391	2,427,092	300,769	2,182,371	251,369	1,884,618	293,845	708,755	671,848	12	21,737	23,889	635	5,013
503	Steam From Other Sources	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
504	Steam Transferred - Credit	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
505	Electric Expenses	100	2,104,874	2,054	2,102,820	7,446	594,693	73,693	529,831	61,591	412,770	71,850	173,661	164,618	3	5,326	5,853	158	1,278
506	Misc Steam Expense	100	6,758,727	6,598	6,753,131	23,914	1,908,838	238,682	1,701,532	187,798	1,375,595	231,064	557,707	528,666	9	17,105	18,768	500	3,945
507	Rents	100	335,478	327	335,151	1,187	94,783	11,745	84,445	8,818	65,788	11,487	27,678	26,237	0	849	933	25	198
509	Allowances	12	2,068,075	2,062	2,065,963	5,823	512,185	53,165	447,271	55,701	472,686	74,466	243,387	188,787	2	4,923	5,410	144	2,002
	Total Operation		182,288,429	181,196	182,087,233	530,368	45,972,495	4,907,158	40,264,149	4,964,829	40,888,331	6,519,704	20,614,017	16,327,782	200	437,485	480,751	12,795	167,329
Maintenance																			
510	Supervision & Engineering	100	1,245,970	1,216	1,244,754	4,408	352,026	43,822	313,831	38,459	244,337	42,580	102,798	97,445	2	3,153	3,465	92	727
511	Structures	100	960,838	838	960,001	3,400	271,488	33,843	241,884	28,118	188,442	32,847	79,282	75,153	1	2,432	2,672	71	561
512	Boiler Equipment	100	15,393,782	15,021	15,378,771	54,458	4,349,232	538,948	3,874,888	450,440	3,018,751	526,188	1,270,055	1,203,920	21	38,952	42,808	1,139	8,893
513	Electric Plant	100	4,024,698	3,927	4,020,772	14,238	1,137,106	140,807	1,013,082	117,767	788,251	137,574	332,055	314,784	8	10,184	11,182	298	2,349
514	Misc Steam Plant	100	4,637,547	4,325	4,633,022	16,408	1,310,253	182,383	1,187,345	138,700	808,432	158,523	382,618	382,694	6	11,735	12,896	343	2,708
	Total Maintenance		28,282,947	25,827	28,237,320	92,910	7,420,112	919,482	6,810,807	788,485	5,150,213	897,735	2,158,808	2,053,977	38	88,455	73,034	1,943	15,328
	Total Steam Expense		208,531,376	208,023	208,324,553	623,308	53,392,607	5,828,639	48,874,956	5,733,113	48,038,544	7,417,437	22,780,825	18,381,769	238	503,940	553,786	14,738	182,655
	Total Steam Expense - Class Percentage		100%	0.0992%	99.9008%	0.2989%	25.6041%	2.7941%	22.4786%	2.7493%	22.0775%	3.5570%	10.9244%	8.8149%	0.0001%	0.2417%	0.2656%	0.0071%	0.0876%

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC Acct	Description of Account	Total WHYR	FERC JULY	PAPUC JULY	RA	RB	RM	SGM	QMI	SL	GLH	L	HYPR	AL	SE	SM	SH	TRAFFIC SIGNALS	
B: Nuclear Power Generation																			
Operation																			
517	Supervision & Engineering	100	13,675,886	13,247	13,582,739	48,028	3,835,645	476,503	3,417,285	387,249	2,682,278	484,061	1,120,078	1,061,753	19	34,352	37,753	1,004	7,922
518	Fuel	12	26,740,809	26,660	26,716,149	72,479	6,376,313	661,762	6,587,209	693,308	5,883,548	926,879	3,029,451	2,349,845	27	61,281	67,340	1,792	24,824
519	Coolants & Water	100	658,458	645	658,111	1,978	157,838	19,659	140,823	16,347	109,553	19,096	48,092	43,691	1	1,414	1,554	41	326
520	Steam Expenses	100	6,455,447	5,323	6,450,124	18,300	1,541,338	190,888	1,373,224	159,633	1,069,923	196,491	450,098	426,681	8	13,804	15,171	404	3,184
521	Steam from Other Sources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
522	Steam Transferred - Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
523	Electric Expenses	100	129,447	126	129,321	458	36,673	4,532	32,584	3,786	25,595	4,425	10,880	10,124	0	328	360	10	78
524	Misc Nuclear Power Expense	100	10,937,324	10,827	10,820,797	59,919	4,785,329	592,988	4,293,388	496,806	3,321,441	678,980	1,397,403	1,324,637	23	42,858	47,101	1,253	9,884
525	Rents	100	48,223,120	45,104	48,178,018	183,523	13,059,491	1,818,299	11,835,105	1,352,543	9,064,440	1,580,022	3,813,810	3,615,026	64	118,982	128,541	3,419	26,974
	Total Operation		108,620,789	106,533	108,514,268	305,683	29,791,524	3,563,430	26,426,437	3,118,474	22,138,468	3,759,924	9,887,413	8,831,736	141	270,988	297,826	7,925	73,299
Maintenance																			
528	Supervision & Engineering	100	3,285,342	3,216	3,282,126	11,658	931,038	115,372	829,491	96,428	648,223	112,643	271,980	257,723	5	8,358	9,164	244	1,923
529	Structures	100	1,841,883	1,802	1,840,281	5,808	483,884	57,483	413,288	48,043	321,978	56,124	135,463	129,499	2	4,155	4,568	121	958
530	Reactor Plant Equipment	100	7,760,707	7,573	7,763,134	27,455	2,182,645	271,707	1,953,495	227,087	1,321,886	265,280	640,292	606,951	11	19,837	21,592	574	4,529
531	Electric Plant	100	3,324,829	3,244	3,321,589	11,782	939,389	116,404	836,913	97,298	652,005	113,651	274,319	280,029	5	8,413	9,246	248	1,840
532	Misc Nuclear Plant	100	8,030,939	7,827	8,013,111	28,376	2,268,168	280,818	2,016,899	234,792	1,572,921	274,178	861,783	827,303	11	20,288	22,305	593	4,681
	Total Maintenance		24,043,689	23,461	24,020,238	85,059	8,783,104	841,784	8,052,187	705,547	4,715,014	821,674	1,983,710	1,880,414	33	60,839	66,863	1,778	14,031
	Total Nuclear Expense		132,664,488	129,994	132,534,484	450,742	38,584,627	4,405,214	32,481,624	3,822,021	28,851,480	4,581,798	11,851,123	10,712,150	174	331,837	364,689	9,702	87,319
	Total Nuclear Expense - Class Percentage		100%	0.098%	99.902%	0.339%	27.568%	3.320%	24.840%	2.881%	20.240%	3.453%	8.932%	8.076%	0.000%	0.250%	0.274%	0.007%	0.065%
D: Other Power Generation																			
Operation																			
546	Supervision & Engineering	100	28,232	28	28,208	93	7,411	919	6,603	788	5,144	897	2,164	2,952	0	88	73	2	15
547	Fuel	12	201,637	201	201,438	568	48,940	5,184	43,810	5,431	48,088	7,261	23,731	18,407	0	480	527	14	185
548	Generation Expense	100	25,322	25	25,287	90	7,154	887	6,374	741	4,988	886	2,089	1,980	0	64	70	2	15
549	Misc Power Prod Exp	100	130,029	127	129,902	480	38,737	4,552	32,730	3,885	25,499	4,445	10,726	10,169	0	328	382	10	76
550	Rents	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Operation		383,220	378	382,841	1,210	101,243	11,541	89,317	10,744	81,697	13,468	38,712	32,808	0	940	1,032	27	301
Maintenance																			
551	Supervision & Engineering	100	26,391	26	26,365	93	7,456	924	6,643	772	5,175	902	2,177	2,064	0	67	73	2	15
552	Structures	100	32,128	31	32,097	114	9,077	1,125	8,087	940	6,308	1,098	2,651	2,513	0	81	89	2	19
553	Gen & Electric Plant	100	36,380	35	36,345	129	10,278	1,274	8,157	1,065	7,134	1,244	3,002	2,845	0	92	101	3	21
554	Misc Power Exp	100	17,924	17	17,907	63	5,064	628	4,512	524	3,515	613	1,479	1,402	0	45	50	1	10
	Total Maintenance		112,823	110	112,713	399	31,876	3,950	28,389	3,301	22,125	3,857	9,308	8,824	0	285	314	8	68
	Total Other Power Production Expense		496,043	488	495,555	1,609	133,119	15,491	117,717	14,046	103,822	17,324	48,021	41,432	1	1,225	1,346	35	367
E: Other Power Supply Expense																			
555	Purchased Power	12	32,269,274	32,188	32,237,108	90,882	7,992,240	826,587	6,979,183	869,148	7,375,752	1,161,956	3,787,780	2,945,820	34	76,823	84,419	2,247	31,245
	Energy Related	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Demand Related	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
556	System Control & Load Dispatch	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
557	Other Expense	100	382,659	373	382,286	1,354	108,113	13,397	96,321	11,187	75,040	13,080	31,571	29,827	1	888	1,064	28	223
	Total Other Power Supply Expense		32,651,933	32,542	32,619,391	92,216	8,100,353	842,984	7,075,504	880,345	7,450,792	1,175,036	3,829,361	2,975,747	35	77,791	85,483	2,275	31,468
	Total Power Production Expense		374,343,840	369,847	373,973,883	1,167,875	98,210,708	11,090,329	86,549,800	10,449,525	80,444,638	13,191,695	38,508,330	32,111,098	448	914,794	1,065,298	26,751	301,810

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total WHYR	FERC JURIS	PAPUC JURIS	BA	BR	BH	ORIGM	QMH	GL	GLH	L	HVPS	AL	BE	EM	BH	TRAFFIC SIGNALE	
	Total Other Power Supply Expense - Class Percentage	100%	0.0997%	99.9003%	0.2824%	24.8062%	2.5817%	21.6695%	2.6911%	22.8188%	3.5977%	11.7278%	9.1135%	0.0001%	0.2382%	0.2618%	0.0070%	0.0984%	
	Total Power Production Expense - Class Percentage	100%	0.0966%	99.9012%	0.3120%	26.2354%	2.9628%	23.1204%	2.7914%	21.4895%	3.5239%	10.2872%	8.5780%	0.0001%	0.2444%	0.2685%	0.0071%	0.0806%	
	Transmission Expense																		
	Operation																		
580	Supervision & Engineering	1	289,398	282	289,114	814	70,190	8,107	78,450	7,687	81,783	10,875	28,945	23,805	0	188	183	6	204
581	Load Dispatching	1	984,018	941	983,078	2,712	233,814	20,342	261,327	26,274	205,808	38,226	88,418	79,299	0	554	608	16	879
582	Station Expense	118	585,815	558	585,059	1,803	138,215	12,026	154,479	14,840	121,659	21,414	72,749	48,878	0	327	360	10	401
583	Overhead Line Expense	117	3,116	3	3,113	8	709	62	788	77	624	110	481	241	0	2	2	0	2
584	Underground Line Expense	1	33,965	33	33,832	98	8,238	717	9,207	890	7,261	2,794	3,397	2,794	0	20	21	1	24
585	Transmission By Others	1	6,411,140	5,280	6,405,860	18,226	1,312,423	114,183	1,488,058	141,888	1,165,221	203,335	641,210	445,111	2	3,108	3,418	91	3,812
586	Misc Trans Expense	101	84,187	60	84,107	174	16,023	1,307	18,816	1,824	13,224	2,328	8,388	5,085	0	38	38	1	44
587	Rents	101	486,227	458	485,769	1,321	113,839	9,904	127,426	12,395	100,204	17,837	83,821	38,809	0	270	298	8	331
	Total Operation		7,837,645	7,814	7,830,031	21,953	1,692,452	164,648	2,116,358	204,584	1,665,774	293,199	815,217	641,829	2	4,482	4,926	131	5,497
	Maintenance																		
588	Supervision & Engineering	1	81,855	80	81,695	173	14,954	1,301	16,714	1,618	13,163	2,317	6,167	5,072	0	35	38	1	43
589	Structures	101	457,572	431	457,141	1,243	107,130	9,321	119,816	11,580	94,298	16,598	59,871	38,333	0	254	279	7	311
570	Station Equipment	101	438,228	418	437,815	1,180	102,601	8,928	114,848	11,891	90,312	15,886	57,348	34,787	0	243	267	7	298
571	Overhead Lines	101	2,275,882	2,144	2,273,838	6,182	532,870	46,381	596,483	57,601	468,043	82,558	287,803	180,724	1	1,262	1,387	37	1,548
572	Underground Lines	1	40,987	40	40,957	116	9,843	805	11,114	1,075	1,541	4,100	3,372	0	24	26	1	29	
573	Misc Transmission Expense	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Total Maintenance		3,274,434	3,088	3,271,348	8,903	787,489	66,774	850,051	82,983	675,688	118,809	425,281	280,289	1	1,818	1,997	53	2,229
	Total Transmission Expense		11,112,079	10,702	11,101,377	30,857	2,659,951	231,420	2,974,410	287,527	2,341,342	412,108	1,240,499	902,128	3	6,299	6,922	184	7,726
	Total Transmission Expense - Class Percentage		100%	0.0963%	99.9037%	0.2777%	23.9375%	2.0826%	26.7674%	2.5875%	21.0702%	3.7087%	11.1635%	8.1184%	0.0000%	0.0567%	0.0623%	0.0017%	0.0695%
	Distribution Expense																		
	Operation																		
580	Supervision & Engineering	8	2,218,899	0	2,218,899	13,228	1,043,319	137,208	843,072	94,808	58,332	5,968	0	0	5	8,986	9,876	281	1,837
581	Load Dispatching	3	1,154,492	1,068	1,153,424	4,034	318,139	41,828	308,377	39,383	219,887	37,293	89,490	88,598	2	2,740	3,011	80	560
582	Station Expense	118	2,833,152	1,421	2,831,731	8,774	773,098	100,388	738,350	84,940	509,488	65,704	479,425	53,888	4	7,584	9,439	198	1,368
583	Overhead Line Expense		3,831,484																
	Primary	119	1,280,522	258	1,280,268	6,070	687,853	57,822	300,081	33,008	64,390	10,282	15,948	0	3	32,735	68,481	659	1,835
	Secondary	118	2,350,962	489	2,350,493	11,143	1,282,857	108,341	550,884	60,600	118,215	18,840	29,280	0	6	60,699	127,563	1,284	3,368
584	Underground Line Expense		802,083																
	Primary	120	731,943	194	731,849	1,604	140,889	16,288	233,881	38,674	213,162	35,313	47,200	0	1	2,179	4,195	72	292
	Secondary	120	70,020	19	70,002	153	13,487	1,568	22,371	3,508	20,388	3,378	4,515	0	0	209	401	7	28
585	Street Lighting & Signal Expense	20	292,590	0	292,590	0	0	0	35,334	0	107,032	0	17,172	133,052	0	0	0	0	0
586	Meter Expense	40	1,285,488	110	1,285,378	3,120	547,056	25,117	590,976	41,112	57,070	10,227	8,587	2,114	0	0	0	0	0
587	Customer Install Expense	20	3,447,813	0	3,447,813	0	0	0	418,344	0	1,281,188	0	202,334	1,567,769	0	0	0	0	0
588	Misc Distribution Expense	102	3,182,187	932	3,181,255	11,418	1,231,722	108,827	810,880	88,154	455,220	69,424	220,734	28,188	5	47,689	108,899	748	2,347
589	Rents	102	1,827,440	533	1,826,907	6,538	705,127	82,300	484,264	56,190	259,458	39,744	126,364	16,708	3	27,244	61,197	428	1,343
	Total Operation		20,683,408	5,002	20,678,407	87,881	8,723,655	657,784	5,312,906	548,478	3,341,778	798,052	1,241,051	1,891,418	27	186,364	392,062	3,778	12,878
	Maintenance																		
590	Supervision & Engineering	8	454,314	0	454,314	2,711	213,810	28,118	172,773	19,449	11,854	1,202	0	0	1	1,841	2,024	54	377
591	Structures	118	488,745	234	488,511	1,810	127,383	16,538	121,309	13,893	85,832	10,824	78,982	8,898	1	1,249	1,555	32	225
592	Station Equipment	118	1,457,120	731	1,456,389	5,027	397,811	51,829	379,713	43,686	282,025	33,782	246,574	27,772	2	3,900	4,854	101	704
593	Overhead Lines		13,504,784																

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total LUMPS	FERC AVBE	PAPUC AVBE	BA	BE	BH	OSIGM	QMH	QL	QLH	L	HYPS	AL	SE	SM	SH	TRAFFIC SIGNALS
118	Primary	13,604,784	2,896	13,602,088	64,012	7,264,311	610,662	3,164,539	249,111	879,072	108,225	168,197	0	32	345,233	732,769	7,376	19,349
119	Secondary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Exhibit JAL-1B
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COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total WMBY	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	ORIGM	OMH	OL	OLH	L	HYP#	AL	SE	SM	SH	TRAFFIC SIGNALS
504	Underground Lines	845,121																
	Primary	845,121	224	844,897	1,852	182,778	18,804	270,008	42,338	248,077	40,788	64,491	0	1	2,615	4,843	83	337
	Secondary	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
505	Line Transformers	105,028																
	Demand Related	105,028	28	105,003	328	42,072	2,737	22,834	3,428	21,448	3,754	4,325	2,520	0	124	1,544	23	88
	Customer Related	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
506	Street Lighting & Signal Systems	84,234																
	Meters	84,234	1	84,234	0	0	0	0	0	0	0	0	0	0	26,257	58,077	0	0
508	Misc Distribution Plant Expense	598,821																
	Total Maintenance	403,934	118	403,818	1,445	155,880	13,771	102,820	12,420	67,350	8,785	27,931	3,893	1	8,022	13,527	95	297
	Total Distribution Expense	17,919,102	4,028	17,914,073	79,344	8,772,982	781,867	4,372,854	492,855	1,387,084	208,171	580,892	42,945	37	388,142	820,093	7,783	21,354
	Total Distribution Expense	38,801,510	9,031	38,892,478	146,425	16,498,837	1,419,441	8,885,680	1,041,431	4,708,860	504,223	1,821,942	1,934,383	83	575,508	1,212,155	11,541	34,333
	Total Distribution Expense - Class Percentage	100%	0.0234%	99.9766%	0.3793%	40.1452%	3.6772%	25.0911%	2.8979%	12.1986%	1.3062%	4.7199%	5.0111%	0.0002%	1.4909%	3.1402%	0.0289%	0.0889%
	Customer Accounts Expense																	
901	Supervision	3,406,371																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	3,406,371	5	3,406,366	13,484	2,392,465	109,572	788,383	54,382	29,825	4,678	2,231	368	0	0	0	0	0
902	Meter Reading	4,382,518																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	4,382,518	8	4,382,512	17,323	3,078,062	140,971	1,028,458	68,988	38,371	6,018	2,871	471	0	0	0	0	0
903	Cust Records & Contracts	13,520,076																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	13,520,076	19	13,520,051	53,441	9,495,822	434,897	3,172,794	215,845	118,378	18,567	8,858	1,452	0	0	0	0	0
904	Uncollectable Accounts	11,000,000																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	11,000,000	19	10,998,981	52,894	9,416,428	431,261	874,866	63,688	12,174	2,011	493	57	38	18	13,604	268	32,123
905	Misc Customer Accounts Expense	187,178																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	187,178	0	187,178	902	160,232	7,338	16,589	1,084	208	34	8	1	0	231	5	5	547
	Total Customer Accounts Expense	32,496,137	49	32,496,088	138,125	24,543,009	1,124,039	5,992,081	404,973	198,802	31,309	14,460	2,347	39	18	13,836	270	32,870
	Customer Service & Info Expense	178,328																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	178,328	0	178,328	849	150,944	6,913	15,827	1,021	194	32	8	1	1	0	218	4	515
908	Customer Assistance	1,740,258																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	1,740,258	3	1,740,255	8,384	1,488,729	68,228	154,228	10,077	1,918	318	78	8	3	2,152	42	5,082	
909	Info, Instruct, Advertise	220,869																
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total LUMIN	FERC JURIS.	PA PUC JURIS.	RA	RE	RH	REG/OM	OMH	OL	OLM	L	HYPB	AL	EE	EM	EN	TRAFFIC SIGNALS	
	Distribution	13	220,069	0	220,069	1,060	189,388	8,828	19,503	1,274	243	40	10	1	1	0	272	6	643
910	Misc. Customer Service & Info.		30,974																
	Production	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	13	30,974	0	30,974	149	28,516	1,214	2,745	179	34	6	1	0	0	0	38	1	90
	Total Customer Assistance & Info. Expense	13	2,167,829	4	2,167,825	10,443	1,855,875	84,983	192,104	12,652	2,389	398	97	11	7	4	2,681	52	6,330
911	Supervision		18,837																
	Production	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	13	18,837	0	18,837	91	16,125	759	1,989	109	21	3	1	0	0	0	23	0	55
912	Demonstration & Selling		4,377,038																
	Production	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	13	4,377,038	8	4,377,028	21,087	3,748,913	171,804	387,911	26,345	4,824	800	198	23	15	8	5,413	106	12,782
913	Advertising		19,427																
	Production	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	13	19,427	0	19,427	94	18,659	762	1,722	112	21	4	1	0	0	0	24	0	57
916	Misc. Sales Expense		118,889																
	Production	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	13	118,889	0	118,888	572	101,892	4,953	10,519	897	131	22	5	1	0	0	147	3	347
	Total Sales Expense		4,533,989	8	4,533,981	21,843	3,881,271	177,757	401,821	28,264	4,997	829	203	23	18	8	5,807	109	13,240
Administrative & General Expense																			
Operation																			
920	Salaries		28,338,845																
	Production	104	15,844,389	16,841	16,828,748	48,879	4,178,453	475,173	5,685,255	443,727	3,394,754	557,213	1,608,124	1,351,019	19	38,812	42,852	1,135	12,538
	Transmission	106	824,842	602	824,340	1,735	149,595	13,015	187,280	16,170	131,877	23,177	69,786	50,736	0	354	389	10	435
	Distribution	107	8,669,514	2,308	8,867,205	37,437	3,967,132	382,918	2,476,374	268,270	1,203,947	128,918	465,829	494,572	18	147,144	309,920	2,951	8,778
921	Office Supplies & Expenses		5,588,877																
	Production	104	3,368,858	3,324	3,363,532	10,599	887,901	100,972	783,089	94,290	719,244	118,405	341,719	287,085	4	8,247	9,063	241	2,664
	Transmission	106	132,787	128	132,659	389	31,788	2,766	35,548	3,438	27,991	4,925	14,825	10,781	0	75	83	2	92
	Distribution	107	2,087,224	491	2,096,733	7,956	841,934	77,118	626,217	58,581	255,833	27,394	98,988	105,094	3	31,267	65,856	627	1,865
922	Admin Expenses Transferred - Credit		(8,171,889)																
	Production	104	(3,712,748)	(3,665)	(3,709,083)	(11,688)	(978,119)	(111,345)	(883,550)	(103,977)	(789,135)	(130,569)	(378,825)	(318,578)	(4)	(9,085)	(9,894)	(268)	(2,937)
	Transmission	106	(146,440)	(141)	(146,299)	(407)	(35,054)	(3,050)	(38,108)	(3,789)	(30,855)	(5,431)	(16,348)	(11,888)	(83)	(81)	(2)	(110)	
	Distribution	107	(2,312,681)	(541)	(2,312,140)	(6,773)	(928,428)	(85,941)	(680,278)	(82,384)	(482,116)	(30,299)	(108,158)	(115,891)	(4)	(34,480)	(72,822)	(681)	(2,057)
923	Outside Services Employment		8,487,154																
	Production	104	5,093,499	5,079	5,088,471	16,035	1,343,248	152,754	1,184,700	142,845	1,088,087	178,127	516,964	434,312	6	12,477	13,711	365	4,030
	Transmission	106	700,800	193	700,707	658	48,090	4,184	53,778	5,188	42,330	7,451	22,428	16,310	0	114	125	3	140
	Distribution	107	3,172,755	742	3,172,013	12,035	1,273,707	116,667	786,080	85,588	387,033	41,443	148,750	158,980	5	47,302	89,630	949	2,822
924	Property Insurance		3,804,103																
	Production	126	5,155,774	5,031	5,150,743	18,251	1,457,214	180,652	1,288,346	150,800	1,010,549	178,209	424,824	403,019	7	13,049	14,340	381	3,003
	Transmission	127	57,196	54	57,142	156	13,411	1,167	15,013	1,450	11,805	2,078	7,409	4,548	0	32	35	1	39
	Distribution	128	391,133	118	391,015	1,409	149,851	13,470	100,358	12,255	57,464	8,775	28,369	3,657	1	4,674	10,357	91	288
925	Injuries & Damages		3,804,775																

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total Utility	FERC JVRIE	PA PUC JVRIE	EA	EE	EH	EE/EM	EMM	EL	ELH	L	HVPS	AL	EE	EM	EH	TRAFFIC SIGNALS
	Production	104 2,168,448	2,141	2,168,347	6,826	531,969	65,033	504,370	60,729	483,243	76,261	220,090	164,902	3	5,312	5,837	165	1,718
	Transmission	106 85,631	82	85,448	239	20,474	1,781	27,894	2,213	18,021	3,172	9,649	6,044	0	48	63	1	58
	Distribution	107 1,350,757	316	1,350,441	5,124	542,264	48,970	338,920	36,442	164,774	17,644	63,754	67,689	2	20,138	42,416	404	1,201
926	Pension & Benefits	13,504,448																
	Production	104 6,123,731	8,019	6,116,712	25,674	2,142,376	243,631	1,889,503	227,607	1,735,430	285,694	824,617	692,893	10	19,800	21,889	692	6,427
	Transmission	106 320,420	309	320,111	890	78,700	6,873	65,768	6,291	67,513	11,863	35,770	28,013	0	182	200	6	223
	Distribution	107 6,060,295	1,184	6,058,111	18,185	2,031,483	188,076	1,269,886	138,522	617,287	68,099	238,839	253,577	8	76,443	158,902	1,513	4,501
927	Franchise Requirements	8																
	Production	104 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	106 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	107 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
928	Regulatory Commission Expense-VT PSB	1,790,074																
	Production	104 1,078,836	1,063	1,075,773	3,390	293,891	32,294	250,462	30,167	230,039	37,870	109,293	91,820	1	2,839	2,899	77	852
	Transmission	106 42,473	41	42,432	118	10,187	895	11,389	899	1,675	4,742	3,448	0	24	26	1	30	
	Distribution	107 870,764	157	870,607	2,644	269,279	24,885	169,302	18,097	81,824	8,762	31,659	33,613	1	10,000	21,063	201	597
929	Duplicate Charges - Credit	(1,247,243)																
	Production	104 (750,292)	(741)	(749,557)	(2,382)	(197,866)	(22,501)	(174,511)	(21,012)	(160,281)	(28,388)	(78,151)	(63,976)	(1)	(1,838)	(2,020)	(54)	(594)
	Transmission	106 (29,593)	(29)	(29,565)	(82)	(7,084)	(616)	(7,921)	(769)	(6,235)	(1,089)	(3,304)	(2,403)	(0)	(17)	(19)	(0)	(21)
	Distribution	107 (467,358)	(109)	(467,250)	(1,773)	(187,822)	(17,186)	(117,266)	(12,609)	(57,011)	(8,105)	(22,059)	(23,420)	(1)	(6,888)	(14,878)	(140)	(416)
930	Miscellaneous General Expense	20,678,428																
	Production	123 18,174,257	15,734	18,108,523	57,043	4,555,612	584,520	4,058,738	471,816	3,181,997	551,168	1,330,322	1,261,049	22	40,800	44,840	1,183	9,409
	Transmission	124 304,935	287	304,648	828	71,394	6,211	70,814	7,717	62,942	11,061	38,899	24,213	0	169	188	5	207
	Distribution	125 4,199,233	1,226	4,199,007	15,020	1,820,296	143,158	1,686,822	129,118	598,198	91,326	290,370	38,385	6	62,602	140,623	985	3,097
931	Rents	11,498,832																
	Production	126 6,917,126	8,749	6,910,377	24,486	1,955,038	242,368	1,741,896	202,452	1,355,780	238,406	569,955	540,701	10	17,506	19,239	512	4,028
	Transmission	127 272,828	257	272,572	742	63,972	5,566	71,812	6,915	58,309	9,911	35,340	21,698	0	152	166	4	188
	Distribution	128 4,308,697	1,298	4,307,399	15,508	1,650,754	148,385	1,105,512	134,985	833,018	98,667	312,514	40,282	6	31,491	114,092	1,000	3,175
	Total Operation	89,814,238	67,289	89,746,940	308,855	27,867,790	2,982,034	22,005,082	2,548,043	16,244,304	2,580,817	7,261,783	6,073,000	122	567,474	1,039,152	12,240	68,264
935	Maintenance of General Plant	3,282,706																
	Production	104 941,485	833	940,652	2,019	169,188	18,238	149,199	17,894	137,033	22,659	65,105	54,895	1	1,571	1,727	46	508
	Transmission	106 488,802	471	488,331	1,357	117,007	10,180	130,839	12,840	102,992	18,128	54,567	39,683	0	277	305	8	340
	Distribution	107 2,132,439	499	2,131,840	8,089	856,074	78,413	535,053	57,531	260,129	27,854	100,548	105,859	4	31,792	66,952	639	1,897
	Total Adm. & General Expense	92,876,944	68,901	92,808,043	320,321	29,010,034	3,089,864	27,820,174	2,938,188	18,744,457	2,649,358	7,482,084	6,274,239	126	591,115	1,106,146	12,932	69,008
	TOTAL OPERATION & MAINTENANCE EXPENSE	556,132,128	458,542	555,673,586	1,835,888	175,657,182	17,217,833	128,616,860	14,858,447	104,445,585	16,789,818	49,068,615	41,224,210	700	2,087,744	3,354,645	51,840	465,117
	Total Customer Accounts Expense - Class Percentage	100%	0.0002%	99.9998%	0.4347%	77.2499%	3.5379%	16.8020%	1.1322%	0.5263%	0.0830%	0.0377%	0.0061%	0.0002%	0.0001%	0.0564%	0.0011%	0.1333%
	Total Adm. & Gen. Expense - Class Percentage	100%	0.0742%	99.9258%	0.3449%	31.2349%	3.3268%	24.5703%	2.8384%	18.0286%	8.0559%	6.7354%	0.0001%	0.0364%	1.1931%	0.0139%	0.0743%	
	TOTAL OPER & MAINT. EXPENSE - Class Percentage	100%	0.0823%	99.9175%	0.3301%	31.5855%	3.0860%	23.1269%	2.6717%	18.7807%	3.0190%	8.6232%	7.4127%	0.0001%	0.3754%	0.6032%	0.0093%	0.0836%

Customer Accounts Expense Summary																		
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution	32,466,137	49	32,498,089	138,125	24,543,009	1,124,039	9,992,091	404,973	198,902	31,309	14,460	2,347	39	19	13,838	270	32,619	
Total	32,466,137	49	32,498,089	138,125	24,543,009	1,124,039	9,992,091	404,973	198,902	31,309	14,460	2,347	39	19	13,838	270	32,619	
Customer Service & Info Expense Summary																		

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total WY87	FERC WY88	PA PUC WY88	RA	RE	RH	QR/QM	QNH	QL	QLH	L	HYPR	AL	RE	RH	SH	TRAFFIC SIGNALS
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	2,187,829	4	2,187,829	10,443	1,855,575	84,893	182,104	12,652	2,389	388	87	11	7	4	2,681	52	8,339
	Total	2,187,829	4	2,187,829	10,443	1,855,575	84,893	182,104	12,652	2,389	388	87	11	7	4	2,681	52	8,339
	Sales Expense Summary																	
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	4,533,888	8	4,533,881	21,843	3,881,221	177,767	401,821	28,254	4,997	829	203	23	18	8	8,607	109	13,240
	Total	4,533,888	8	4,533,881	21,843	3,881,221	177,767	401,821	28,254	4,997	829	203	23	18	8	8,607	109	13,240
	Administration & General Expense Summary																	
	Production	60,049,381	58,957	59,990,424	200,051	18,387,873	1,842,789	14,507,502	1,717,188	12,332,748	2,083,958	5,657,937	4,920,741	77	149,379	164,163	4,388	41,641
	Transmission	2,354,792	2,255	2,352,537	8,602	860,461	48,781	826,892	80,583	483,329	88,833	274,842	190,082	1	1,327	1,459	39	1,628
	Distribution	20,472,771	2,889	20,469,882	113,718	12,081,700	1,098,315	7,885,780	858,405	3,818,380	428,568	1,545,503	1,585,545	59	58,499	64,523	8,528	26,738
	Total	82,876,944	64,101	82,809,843	322,371	28,010,034	3,089,884	22,820,174	2,656,188	18,744,457	2,849,358	7,482,084	6,714,239	128	591,115	1,108,146	12,932	69,009
403	Depreciation Expense (P338)																	
	Production																	
	Steam Production (310 - 316)	112	33,351,123	32,587	33,318,538	118,490	9,350,512	1,148,388	8,321,683	871,071	6,807,486	1,143,808	2,824,527	45	84,091	92,404	2,458	20,269
	Nuclear Production (320 - 325)	113	108,200,173	103,559	106,006,814	378,071	30,119,214	3,748,837	28,849,505	3,116,173	20,719,580	3,824,201	8,262,825	147	269,217	285,971	7,870	60,712
	Other Production (340 - 348)	114	834,025	817	833,408	2,281	181,469	22,818	181,880	18,708	122,158	21,551	49,981	1	1,614	1,774	47	344
	Total Production Plant	112	140,185,321	136,783	140,048,558	496,852	39,651,184	4,919,822	35,332,048	4,104,951	27,449,242	4,789,580	11,521,079	184	354,911	380,049	10,375	81,316
	Transmission Plant																	
350	Land and Land Rights	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
352	Structures and Improvements	118	140,451	133	140,318	385	33,149	2,884	37,048	3,683	29,178	5,136	17,448	0	0	0	0	0
353	Station Equipment	118	2,527,165	2,400	2,524,765	6,919	586,453	51,892	686,639	84,473	525,010	92,409	315,943	1	79	86	2	98
354	Towers & Fixtures	117	1,072,809	983	1,071,826	2,833	244,247	21,250	273,959	28,402	214,991	37,841	165,525	0	528	1,552	41	1,732
355	Poles & Fixtures	117	125,604	115	125,489	332	78,598	2,488	32,075	3,091	25,171	4,430	18,380	0	69	74	17	709
358	Overhead Conductor and Devices	101	809,008	858	808,152	2,489	212,824	18,516	238,222	23,065	187,332	32,973	118,940	0	504	554	2	83
357	Underground Conduit	1	458,859	448	458,411	1,291	111,292	9,883	124,388	12,030	97,962	17,243	45,894	0	264	290	8	323
358	Underground Conductors and Devices	1	460,981	450	460,541	1,297	111,809	9,728	124,968	12,088	98,417	17,323	46,107	0	265	291	8	325
359	Roads & Trails	1	323	323	323	1	95	8	102	10	84	15	38	0	0	0	0	0
	Total Transmission Plant	101	5,695,280	5,385	5,689,895	15,527	1,338,465	116,449	1,487,405	144,681	1,178,144	207,369	727,275	2	3,170	3,483	93	3,888
	Distribution Plant																	
360	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
361	Structures & Improvement	118	680,862	341	680,521	2,349	185,790	24,125	178,959	20,413	122,435	15,790	115,215	1	1,823	2,288	47	329
362	Station Equipment	118	7,591,164	3,807	7,587,357	28,188	2,071,437	269,874	1,872,881	227,589	1,365,072	178,047	1,284,575	10	20,320	25,290	524	3,666
363	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
364	Poles, Towers, Fixtures	119	5,184,751	1,037	5,193,714	24,623	2,780,444	234,874	1,217,272	133,904	261,212	41,630	64,899	0	12	132,797	281,887	2,837
365	Overhead Conductor & Devices	118	3,755,554	750	3,754,804	17,801	2,017,356	169,875	880,029	98,808	188,844	30,096	48,774	0	8	95,008	203,776	2,051
368	Underground Conduit	120	1,090,387	288	1,090,098	2,388	2,017,020	24,261	348,369	54,627	317,492	52,599	20,305	0	1	3,245	6,248	107
387	Underground Lines	120	3,130,687	828	3,128,858	8,880	603,003	68,858	1,000,228	158,842	911,574	151,021	201,859	0	3	9,317	17,940	308
368	Line Transformers	121	3,602,007	892	3,601,115	11,250	1,442,859	93,857	776,243	117,565	735,582	128,756	148,316	4	4,242	52,967	784	2,259

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total MWH	FERC JURL	PA PUC JURLS	BA	BE	BH	QBGM	QMH	QL	QLH	L	HYPB	AL	BE	SM	BH	TRAFFIC SIGNALS	
369	Services	122	1,383,861	187	1,383,864	8,438	1,070,653	50,490	155,704	14,388	45,060	7,093	16,926	15,977	0	422	464	12	88
370	Meters	102	4,282,205	1,260	4,280,955	15,317	1,852,311	145,987	1,087,901	131,870	607,979	83,130	286,107	38,154	6	63,838	143,402	1,004	3,140
371	Install on Cust Premises*	20	2,773	0	2,773	0	0	0	335	0	1,014	0	183	1,281	0	0	0	0	0
372	Leased Property on Cust Premise	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
373	Street Lights & Signal Systems	19	2,015,246	0	2,015,246	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Distribution Plant		32,728,497	8,361	32,720,136	113,216	12,043,873	1,082,201	7,816,020	853,784	4,558,264	688,162	2,244,938	300,474	46	936,278	2,145,203	7,884	23,993
General Plant																			
389	Land & Land Rights																		
	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
390	Structures & Improvements																		
	Production	100	391,722	382	391,388	1,388	110,698	13,718	98,816	11,464	78,027	13,392	32,323	30,640	1	991	1,089	29	229
	Transmission	101	15,452	16	16,437	42	3,818	316	4,048	391	3,184	560	2,022	1,227	0	9	8	0	11
	Distribution	102	248,035	71	243,984	873	94,182	8,320	81,998	7,504	34,648	5,307	18,875	2,231	0	3,838	8,172	57	178
391	Office Furniture & Equipment																		
	Production	100	4,057,587	3,858	4,053,828	14,354	1,148,388	142,058	1,021,368	118,730	795,700	138,688	334,769	317,338	8	10,267	11,284	300	2,368
	Transmission	101	180,041	151	158,890	435	37,470	3,780	41,842	4,050	32,882	5,805	20,941	12,708	0	89	88	3	109
	Distribution	102	2,527,482	738	2,526,744	8,040	976,242	88,168	842,111	77,716	358,847	54,888	174,771	23,110	4	37,880	84,840	683	1,858
392	Transportation Equipment																		
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
393	Stores Equipment																		
	Production	100	50,835	60	50,785	180	14,362	1,780	12,798	1,487	9,959	1,738	4,194	3,976	0	129	141	4	30
	Transmission	101	2,005	2	2,003	5	469	41	525	51	413	73	282	158	0	1	1	0	1
	Distribution	102	31,868	9	31,657	113	12,218	1,080	8,045	974	4,496	689	2,180	280	0	472	1,060	7	23
394	Tools, Shop & Garage Equipment																		
	Production	100	248,284	242	248,052	878	70,161	8,693	82,500	7,265	48,691	8,487	20,485	18,419	0	828	690	18	145
	Transmission	101	9,793	9	9,784	27	2,283	189	2,568	248	2,018	355	1,281	778	0	5	6	0	7
	Distribution	102	154,655	45	154,818	553	59,878	5,273	39,282	4,756	21,959	3,364	10,695	1,414	0	2,306	5,179	38	114
395	Laboratory Equipment																		
	Production	100	138,863	136	138,726	495	38,516	4,887	35,206	4,093	27,427	4,781	11,539	10,938	0	354	389	10	82
	Transmission	101	5,517	5	5,512	15	1,282	112	1,446	140	1,137	200	722	438	0	3	3	0	4
	Distribution	102	87,121	25	87,095	312	33,616	2,970	22,133	2,679	12,369	1,895	6,024	797	0	1,288	2,917	20	64
396	Power Operated Equipment																		
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
397	Communication Equipment																		
	Production	100	6,504,355	6,347	6,498,008	23,010	1,837,688	227,721	1,637,251	180,325	1,275,516	222,335	536,638	508,694	9	16,459	18,088	481	3,798
	Transmission	101	258,348	247	258,308	697	60,065	5,228	67,233	6,493	52,870	9,308	33,588	20,371	0	142	158	4	174
	Distribution	102	4,051,581	1,183	4,050,398	14,492	1,563,324	138,125	1,029,310	124,578	575,235	88,115	280,180	37,045	6	60,401	135,879	950	2,979
398	Misc Equipment																		
	Production	100	24,184	24	24,140	85	8,827	848	6,882	787	4,739	828	1,984	1,890	0	61	87	2	14
	Transmission	101	854	1	853	3	223	19	250	24	187	35	125	76	0	1	1	0	1
	Distribution	102	15,051	4	15,047	54	5,808	513	3,824	483	2,137	327	1,041	138	0	224	504	4	11

COST OF SERVICE STUDY
(By FERC Account - 1996)

FERC ACCT	Description of Account	Total WBY	FERC WBY	PA PUC WBY	RA	RE	RH	ORGM	QMN	OL	GLN	L	MVPR	AL	SE	EM	SH	TRAFFIC SIGNALS
399	Other Tangible Property																	
	Production	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total General Plant	18,978,777	13,640	18,965,136	67,049	6,076,103	651,329	4,709,535	584,135	3,341,361	661,256	1,492,618	993,674	26	135,159	270,175	2,519	12,197
	Total Depreciation Expense	197,688,875	185,150	197,423,725	692,643	58,108,826	6,769,801	49,244,098	6,787,552	38,526,011	8,254,348	15,985,911	12,695,065	267	1,429,518	2,808,910	20,671	121,392
	Total Depreciation Expense - Class Percentage	100%	0.0836%	99.9164%	0.3505%	29.9150%	3.4292%	24.8223%	2.9190%	18.4854%	3.1653%	8.0905%	6.4250%	0.0001%	0.7235%	1.4216%	0.0105%	0.0614%
	Amortization Expense (P336)																	
404	Amortization of Leasehold Improvements																	
	Production	100	4,670,192	4,670,192	16,543	1,321,169	163,718	1,177,070	136,831	917,008	159,844	395,805	365,718	6	11,832	13,004	346	2,729
	Transmission	101	448,778	423	448,356	1,218	105,072	8,141	117,811	11,358	92,488	16,270	35,635	0	249	273	7	305
	Distribution	102	3,068,938	898	3,068,040	10,977	1,184,165	104,825	779,688	84,364	435,721	88,744	212,212	28,061	4	45,752	102,772	720
405	Amortization of Transition Costs (Acct 405)																	
	Production	100	83,548,333	81,525	83,466,808	795,568	23,605,041	2,925,077	21,030,483	2,444,722	18,383,983	2,855,891	6,983,103	6,534,167	115	211,408	232,338	6,180
	Transmission	101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Amortization Expense	91,742,230	87,408	91,654,824	324,307	26,215,447	3,202,658	23,104,812	2,687,275	17,820,199	3,088,758	7,548,842	6,963,574	126	269,241	348,588	7,253	54,045
	Total Amortization Expense - Class Percentage	100%	0.0931%	99.9047%	0.3535%	28.5751%	3.4908%	25.1845%	2.8292%	19.4340%	3.3777%	8.2294%	7.9804%	0.0001%	0.2935%	0.3787%	0.0079%	0.0589%
	Total Deprec/Amort Expense - Class Percentage	100%	0.0873%	99.9127%	0.3515%	29.4901%	3.4467%	25.0055%	2.8222%	18.7662%	3.2327%	8.1345%	6.7945%	0.0001%	0.5871%	1.0912%	0.0097%	0.0606%

Total General Plant Depreciation Summary																		
Production	11,418,869	11,140	11,405,728	40,389	3,225,828	399,711	2,873,810	334,071	2,238,869	390,257	941,842	892,892	16	28,889	31,749	845	6,662	
Transmission	450,310	424	449,885	1,223	105,430	9,173	118,012	11,368	92,801	16,334	56,925	35,757	0	250	274	7	306	
Distribution	7,111,599	2,026	7,109,573	25,437	2,244,048	242,445	1,806,213	218,689	1,008,680	154,664	491,755	65,024	10	105,020	238,152	1,668	5,228	
Total	19,978,777	13,640	19,965,136	67,049	6,075,103	651,329	4,788,535	564,135	3,341,361	561,256	1,492,618	993,674	26	135,159	270,175	2,519	12,197	
Total Plant Depreciation/Amortization Summary (Excluding General Plant)																		
Production	228,408,836	222,651	228,186,985	808,963	64,577,385	8,008,616	57,539,581	6,688,504	44,750,234	7,805,295	18,789,888	17,846,852	315	578,152	635,381	18,801	132,789	
Transmission	6,144,058	5,608	6,138,251	16,746	1,443,537	125,580	1,615,016	156,039	1,270,630	223,649	785,996	488,579	2	3,419	3,757	100	4,183	
Distribution	35,188,433	19,257	35,188,176	124,182	13,228,029	1,189,829	8,385,889	1,049,149	4,891,899	762,899	2,457,159	328,525	49	882,030	2,241,925	8,494	26,258	
Total	270,352,328	238,915	270,113,413	949,901	79,248,959	9,324,031	67,550,286	7,880,681	51,012,849	8,791,849	22,043,134	18,664,965	367	1,563,601	2,887,123	25,405	163,241	
Total Plant Depreciation/Amortization Summary																		
Production	239,826,705	233,891	239,592,713	849,352	67,803,020	8,408,327	60,413,391	7,020,575	46,889,103	8,195,552	19,741,930	18,739,744	331	607,041	667,140	17,746	139,461	
Transmission	6,594,368	6,232	6,588,136	17,999	1,548,987	134,763	1,733,028	167,435	1,365,431	238,983	844,917	525,336	2	3,669	4,031	107	4,489	
Distribution	42,819,032	12,332	42,807,699	148,630	15,972,089	1,428,271	10,292,401	1,266,816	8,001,875	917,571	2,949,905	393,559	61	1,988,050	2,489,127	10,071	31,477	
Total	289,331,105	252,556	289,078,549	1,016,981	85,324,073	9,972,361	72,348,820	8,454,827	54,354,210	9,352,105	23,535,752	19,658,639	393	1,698,759	3,157,298	27,924	175,437	

Exhibit JAL-1B
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COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total USDY	FERC JURIS.	PA PUC JURIS.	BA	BE	BH	ORIGM	QMJ	QL	QLN	L	HYPE	AL	RE	EM	SH	TRAFFIC SIGNALS
	Taxes (P202)																	
408	Taxes Other Than Income Taxes	44,083,633																
	Production	110 35,817,995	26,740	35,892,255	125,515	11,381,088	1,206,881	8,141,555	1,067,778	6,400,511	1,073,599	2,984,760	1,871,818	47	213,681	417,097	4,646	23,322
	Transmission	110 474,217	340	473,877	1,837	160,282	15,934	120,894	14,098	84,504	14,174	38,143	24,713	1	2,821	5,507	81	308
	Distribution	110 7,870,821	5,497	7,865,324	26,806	2,430,596	287,743	1,852,318	228,040	1,366,924	228,283	633,188	399,754	10	45,835	89,077	982	4,981
409	Federal Income Tax	93,063,328																
	Production	103 73,568,884	55,728	73,513,268	266,348	22,897,768	2,468,417	18,633,447	2,183,981	13,230,317	2,238,859	6,043,820	4,158,894	96	481,633	904,027	8,828	47,014
	Transmission	103 2,183,457	1,854	2,181,803	7,808	879,584	73,280	553,023	84,225	382,663	86,441	178,375	123,432	3	13,701	28,831	282	1,395
	Distribution	103 17,250,887	13,067	17,237,820	60,110	5,368,203	678,808	4,388,280	507,425	3,102,322	524,934	1,417,190	875,202	22	108,248	211,982	2,068	11,024
409	State Income Tax	34,348,324																
	Production	103 27,168,180	20,580	27,148,800	84,870	8,456,194	811,591	6,881,371	799,188	4,885,884	826,741	2,231,995	1,535,888	35	170,482	333,859	3,258	17,382
	Transmission	103 806,355	811	805,744	2,810	250,972	27,955	204,232	23,718	145,011	24,537	68,243	45,584	1	5,060	9,898	87	515
	Distribution	103 8,370,789	4,826	8,365,983	22,199	1,882,858	213,755	1,613,584	187,393	1,145,884	193,859	523,371	360,144	8	38,978	78,285	764	4,071
410	Deferred Income Tax	(28,940,324)																
	Production	100 (30,241,839)	(28,509)	(30,212,430)	(108,987)	(8,544,302)	(1,058,788)	(7,812,384)	(884,815)	(5,930,500)	(1,033,745)	(2,495,082)	(2,365,167)	(42)	(76,523)	(84,098)	(2,237)	(17,648)
	Transmission	101 370,838	349	370,589	1,007	88,847	7,550	97,211	8,388	76,444	13,455	48,536	28,454	0	208	228	8	252
	Distribution	102 2,850,877	955	2,828,922	10,483	1,130,817	89,911	744,543	90,113	418,091	63,737	202,851	28,798	4	43,691	98,142	687	2,155
410	Deferred State Income Tax	1,014,841																
	Production	100 802,778	783	801,892	2,840	226,810	28,106	202,672	23,490	157,426	27,441	66,233	62,784	1	2,031	2,232	59	468
	Transmission	101 23,826	22	23,803	85	5,578	485	6,244	803	4,810	864	3,118	1,892	0	13	15	0	18
	Distribution	102 188,240	55	188,185	673	72,633	6,417	47,823	5,788	28,728	4,084	13,018	1,721	0	2,808	8,304	44	138
411	Income Tax Deferred In Prior Years	(28,811,485)																
	Production	100 (28,981,004)	(28,780)	(28,932,744)	(102,455)	(8,182,388)	(1,013,942)	(7,288,952)	(847,433)	(5,878,307)	(888,880)	(2,388,410)	(2,284,987)	(40)	(73,282)	(80,537)	(2,142)	(18,900)
	Transmission	101 (858,535)	(810)	(858,725)	(2,334)	(201,241)	(17,508)	(225,267)	(21,753)	(177,138)	(31,178)	(112,487)	(68,251)	(0)	(477)	(524)	(14)	(585)
	Distribution	102 (8,780,846)	(1,882)	(8,788,884)	(24,280)	(2,820,322)	(231,514)	(1,725,250)	(208,808)	(884,164)	(147,691)	(468,583)	(82,093)	(10)	(101,240)	(227,414)	(1,582)	(4,982)
411	Amortization of Investment Tax Credits	(7,838,483)																
	Production	100 (8,200,523)	(8,050)	(8,194,472)	(21,938)	(1,751,843)	(217,084)	(1,580,772)	(181,435)	(1,215,934)	(211,949)	(511,570)	(484,932)	(8)	(15,690)	(17,243)	(459)	(3,818)
	Transmission	101 (184,028)	(173)	(183,852)	(500)	(43,088)	(3,748)	(48,227)	(4,857)	(37,925)	(6,875)	(24,079)	(14,613)	(0)	(102)	(112)	(3)	(125)
	Distribution	102 (1,453,935)	(424)	(1,453,510)	(5,200)	(561,008)	(49,587)	(368,374)	(44,706)	(208,427)	(31,820)	(100,537)	(13,284)	(2)	(21,675)	(48,589)	(341)	(1,089)
411	Gain From Disposal Of Allowances	(226,413)																
	Production	100 (178,022)	(175)	(178,847)	(633)	(50,579)	(8,268)	(45,063)	(5,238)	(35,107)	(6,119)	(14,770)	(14,001)	(0)	(453)	(488)	(13)	(104)
	Transmission	101 (5,313)	(5)	(5,308)	(14)	(1,244)	(108)	(1,382)	(134)	(1,095)	(193)	(695)	(472)	(0)	(3)	(3)	(0)	(4)
	Distribution	102 (41,978)	(12)	(41,966)	(150)	(19,127)	(1,431)	(19,899)	(1,281)	(5,960)	(913)	(2,993)	(384)	(0)	(525)	(1,496)	(10)	(33)
	Total All Taxes	100 810,821	62,707	100,748,214	348,280	33,148,967	3,295,942	25,678,058	2,884,846	17,181,875	2,841,725	8,311,515	4,328,832	127	819,812	1,722,867	14,982	67,946
	<i>Total All Taxes - Class Percentage</i>	<i>100%</i>	<i>0.0622%</i>	<i>99.9378%</i>	<i>0.3455%</i>	<i>32.8823%</i>	<i>3.2694%</i>	<i>25.4725%</i>	<i>2.8608%</i>	<i>17.0438%</i>	<i>2.8189%</i>	<i>8.2447%</i>	<i>4.2951%</i>	<i>0.0001%</i>	<i>0.8133%</i>	<i>1.7091%</i>	<i>0.0148%</i>	<i>0.0674%</i>

Total Taxes Summary																		
Production	71,876,447	38,837	71,837,610	247,383	24,432,715	2,318,892	18,350,276	2,135,405	11,813,390	1,924,667	5,895,865	2,500,288	89	681,880	1,474,838	11,938	49,898	
Transmission	2,809,918	1,888	2,807,931	10,298	927,672	102,925	706,578	85,487	497,377	81,426	188,174	141,789	4	21,218	41,848	408	1,774	
Distribution	28,124,555	21,982	28,102,673	80,829	7,788,578	874,124	6,822,256	783,854	4,881,207	835,682	2,216,378	1,682,847	34	116,813	298,281	2,814	18,227	
Total	100,810,921	62,707	100,748,214	348,280	33,148,967	3,295,942	25,678,058	2,884,846	17,181,875	2,841,725	8,311,515	4,328,832	127	819,812	1,722,867	14,982	67,946	

COST OF SERVICE STUDY
(By FERC Account - 1996)

FERC ACCT	Description of Account	Total UNITS	FERC JURISL	PA PUC JURISL	BA	BL	BM	QB/QM	QNH	QL	QLM	L	HYPR	AL	SE	SM	SH	TRAFFIC SIGNALS	
REVENUE																			
447	Off-System Sales																		
	Production	100	(34,245,464)	(33,416)	(34,212,048)	(121,160)	(9,876,426)	(1,199,954)	(8,820,135)	(1,002,082)	(8,716,599)	(1,170,598)	(2,825,401)	(2,878,275)	(47)	(88,654)	(95,233)	(2,633)	(19,994)
	Transmission	101	(2,254,574)	(2,124)	(2,252,450)	(6,123)	(527,858)	(45,925)	(590,853)	(57,059)	(484,831)	(81,781)	(265,002)	(178,024)	(1)	(1,250)	(1,374)	(37)	(1,533)
	Distribution	102	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Total		(36,600,038)	(35,540)	(36,464,498)	(127,273)	(10,203,283)	(1,244,879)	(9,210,988)	(1,059,121)	(7,180,239)	(1,252,377)	(3,120,402)	(2,857,299)	(48)	(87,804)	(96,606)	(2,670)	(21,517)
454	Other Revenues																		
	Production	100	(17,726,476)	(17,298)	(17,708,178)	(82,707)	(5,008,096)	(820,540)	(4,461,768)	(518,668)	(3,476,399)	(605,901)	(1,462,429)	(1,388,277)	(24)	(44,852)	(49,292)	(1,311)	(10,344)
	Transmission	101	(8,248,853)	(5,894)	(8,240,960)	(16,968)	(1,482,581)	(127,245)	(1,837,104)	(168,095)	(1,287,376)	(228,598)	(817,375)	(498,031)	(2)	(3,464)	(3,808)	(101)	(4,248)
	Distribution	102	(14,198,307)	(4,118)	(14,194,189)	(60,483)	(6,443,764)	(488,974)	(3,684,237)	(433,803)	(2,902,058)	(308,830)	(875,588)	(118,989)	(20)	(210,327)	(472,457)	(3,389)	(10,372)
	Total		(39,980,636)	(27,299)	(39,853,337)	(150,137)	(11,914,331)	(1,228,789)	(6,883,129)	(1,110,567)	(6,766,442)	(1,139,327)	(2,255,370)	(2,011,306)	(46)	(256,643)	(525,655)	(4,721)	(24,864)
Rate Base																			
	Electric Plant in Service (P207)		4,201,155,890	3,171,113	4,197,984,578	14,852,760	1,310,139,581	141,180,848	1,063,934,906	123,664,389	754,423,974	127,590,733	344,118,088	238,288,025	5,493	26,608,547	52,187,974	607,680	2,885,781
	Less: Accum Depreciation (P219)		(1,695,262,221)	(1,350,037)	(1,693,912,184)	(6,894,355)	(519,332,492)	(56,881,232)	(428,740,785)	(49,281,815)	(306,589,281)	(52,327,854)	(137,589,674)	(103,061,737)	(2,297)	(11,724,031)	(23,222,574)	(188,825)	(1,895,423)
	Net Book Value		2,505,893,469	1,821,076	2,504,072,392	8,758,395	790,807,089	84,299,416	637,194,121	74,382,774	447,834,694	75,262,879	206,518,413	133,224,288	3,286	14,884,517	28,965,398	318,754	1,820,358
	Add: Land/Plant Held For Future Use (P214)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CWIP - Contr. Work In Progress (P216)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Less: Accum Deferred Income Taxes (P273-277)		(388,169,514)	(303,463)	(387,866,051)	(1,358,015)	(119,778,892)	(13,142,937)	(88,208,305)	(11,426,601)	(70,460,752)	(11,963,498)	(31,718,255)	(22,862,077)	(513)	(2,283,882)	(4,373,383)	(44,831)	(245,321)
	Total Adjusted Net Plant		2,117,723,954	1,517,613	2,116,208,341	7,400,380	621,027,418	71,156,479	538,985,816	62,956,173	377,373,942	63,299,382	174,802,157	110,362,711	2,773	12,598,635	24,592,016	273,923	1,375,027
	Return Per Books	9.61%	203,513,272	145,843	203,367,428	711,177	64,485,735	6,838,138	51,796,537	6,050,088	38,265,636	6,083,071	18,789,487	10,605,809	267	1,310,728	2,363,793	26,324	132,141
Adjustments To Rate Base For Ratemaking																			
	Add: Regulatory Assets		544,788,485	491,618	544,296,868	1,902,673	169,211,970	18,542,801	137,803,017	15,898,522	104,083,463	17,983,727	45,767,540	38,720,050	717	2,017,568	3,189,572	47,535	326,683
	Phlux		78,399,257	76,500	78,322,757	277,352	22,150,764	2,744,805	18,734,358	2,294,054	15,374,239	2,678,883	6,468,282	6,131,462	108	188,379	218,019	5,789	45,750
	Brunel Island		28,758,563	28,062	28,730,501	101,739	8,125,202	1,008,855	7,238,994	841,509	5,639,808	983,040	2,372,707	2,248,155	40	72,770	78,974	2,127	16,782
	Wenck		15,284,814	14,924	15,278,890	54,109	4,321,288	535,484	3,849,878	447,547	2,999,361	522,818	1,261,897	1,196,187	21	38,702	42,533	1,131	8,825
	Deferred Taxes		(485,985,845)	(478,254)	(485,557,391)	(1,691,383)	(142,267,983)	(16,412,117)	(122,868,860)	(14,171,258)	(82,134,021)	(15,876,755)	(41,013,787)	(33,537,089)	(632)	(1,865,741)	(3,278,581)	(44,302)	(297,085)
	Working Capital		69,840,000	64,210	69,875,280	246,607	29,278,221	2,426,780	17,828,287	2,048,223	13,451,169	7,328,778	6,762,950	5,118,442	65	232,724	348,215	5,922	41,708
	Total Adjustment To Rate Base		251,195,566	247,558	250,948,010	891,097	70,768,958	8,843,618	63,188,481	7,357,599	48,413,847	8,622,492	20,818,690	18,878,197	349	599,452	600,253	18,213	145,764
	Rate Base Adjusted For Ratemaking		2,368,919,520	1,765,172	2,367,156,351	8,291,477	71,196,376	80,000,097	602,175,266	70,313,771	426,287,789	71,921,874	195,420,848	130,240,408	3,123	13,198,087	25,192,269	292,136	1,520,801
	Return Per Books	9.61%	227,653,168	169,633	227,483,533	798,811	71,288,832	7,689,009	57,889,048	6,757,153	41,014,307	8,911,692	18,778,943	12,516,103	300	1,268,336	2,420,877	28,074	148,149
Expenses																			

COST OF SERVICE STUDY

(By FERC Account - 1996)

FERC ACCT	Description of Account	Total MWH	FERC JURIS.	PA PUC JURIS.	RA	RB	RC	RRIGM	RRMH	RL	RLH	L	HYP#	AL	RE	RM	RH	TRAFFIC SIGNALE
	Operation and Maintenance (P320)	556,132,128	458,542	555,873,586	1,835,889	176,837,182	17,217,833	128,816,880	14,858,447	104,445,585	18,769,818	49,068,015	41,224,210	700	2,087,744	3,354,845	51,840	485,117
	Depreciation & Amortization Expense (P330)	289,331,105	262,550	289,078,549	1,018,950	86,324,073	9,872,381	72,348,820	8,454,827	64,354,210	8,353,105	23,535,752	19,658,839	383	1,898,759	3,157,288	27,924	176,437
	Taxes (P282)	100,810,821	82,707	100,728,214	348,280	33,148,987	3,285,842	25,878,058	2,884,848	17,181,876	2,841,775	8,311,615	4,328,832	127	819,812	1,722,887	14,882	87,948
	Total Expenses	946,274,154	773,805	945,600,349	3,201,129	294,130,221	30,486,136	226,843,839	26,298,121	175,981,770	28,984,898	80,915,883	65,212,781	1,220	4,806,415	8,334,910	94,727	709,500
	Add: Gross Receipts Tax	36,153,777	38,251	36,115,526	149,468	18,726,650	1,150,848	8,510,824	889,720	4,372,842	1,183,080	3,078,024	1,229,871	38	139,044	546,988	7,387	72,072
	Total Expenses/wGRT	982,427,931	812,056	981,615,875	3,350,597	310,856,872	31,636,984	235,164,683	27,267,840	180,354,712	30,147,768	83,993,907	66,442,451	1,258	4,744,459	8,781,878	102,124	780,573
	Less: Off-System Sales (P311)	(36,500,038)	(35,540)	(36,464,498)	(127,273)	(10,203,283)	(1,244,879)	(9,210,989)	(1,059,121)	(7,180,230)	(1,252,377)	(3,120,402)	(2,857,299)	(48)	(87,904)	(98,606)	(2,570)	(21,517)
	Other Revenues (P300)	(38,080,838)	(27,299)	(38,053,337)	(130,137)	(11,814,331)	(1,228,789)	(9,883,126)	(1,110,587)	(6,768,442)	(1,138,327)	(3,255,370)	(2,011,308)	(46)	(258,843)	(525,555)	(4,721)	(24,984)
	Net Expenses	907,847,257	749,217	907,088,040	3,093,188	289,739,258	29,183,107	214,260,545	25,088,152	186,408,039	27,756,054	77,618,135	61,573,848	1,164	4,397,912	8,159,718	94,834	734,092
	Cost of Service	1,135,500,423	918,850	1,134,591,573	3,889,997	360,025,890	36,851,116	272,120,591	31,855,305	207,422,346	34,887,748	95,398,078	74,089,949	1,464	5,666,748	10,680,893	122,908	880,241
	Class Percentages	100.000%	0.081%	99.919%	0.343%	31.708%	3.245%	23.868%	2.805%	18.267%	3.053%	8.489%	6.525%	0.030%	0.438%	0.932%	0.011%	0.076%
	mWh @ METER	12,408,326	12,808	12,393,517	33,848	2,877,288	309,038	2,621,147	328,256	2,884,887	455,220	1,509,474	1,201,824	13	28,618	31,448	637	11,630
	AVERAGE EMBEDDED COST / kWh	0.09153	0.07174	0.09155	0.11493	0.12092	0.11924	0.10382	0.09704	0.07180	0.07616	0.06386	0.09165	0.11259	0.18900	0.33845	0.14684	0.07563

Exhibit JAL-1B
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Schedule C

**Cost of Service Study Results
Basis for Retail Rates
(Pages 1-6)**

COST OF SERVICE STUDY

(1996)

Exhibit JAL - 1 (C)
Page 1 of 6

Alloc #	Total Utility	PERC JURIS.	PA PUC JURIS.	RA	BS	BS	BS	DRMM	GMH	QL	QLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
	Total Retail Production Cost	680,178,055	832,457	879,340,588	2,939,212	244,707,617	28,457,031	213,582,737	25,246,804	177,862,388	28,978,344	80,755,855	68,753,687	1,127	2,692,414	3,684,355	70,723	610,923
	Production Energy (50,509, 518, 547, 555)	218,884,908	216,007	218,488,901	610,126	50,867,081	5,570,585	48,884,505	5,808,239	49,527,428	7,602,418	25,501,777	19,780,882	228	515,858	568,886	15,088	209,808
100	less: Off-System Sales	(33,975,902)	(33,153)	(33,942,749)	(120,198)	(8,599,265)	(1,189,517)	(8,552,282)	(894,175)	(8,602,737)	(1,161,381)	(2,803,141)	(2,857,193)	(47)	(89,972)	(84,483)	(2,513)	(19,827)
100	less: Transmission Off-System Sales Low Revenue	(283,382)	(283)	(283,283)	(834)	(24,180)	(8,438)	(87,853)	(7,888)	(52,882)	(9,214)	(22,240)	(21,882)	(8)	(882)	(750)	(20)	(152)
	Net Production Energy	187,439,444	187,591	187,256,854	488,977	43,991,657	4,271,640	38,244,070	4,834,177	42,811,829	6,631,822	22,078,377	17,102,607	181	429,204	471,834	12,556	189,824
12.4	less: Transmission Loss - Energy	1,829,714	1,825	1,828,089	4,589	403,637	41,897	352,474	43,895	372,502	58,683	191,802	148,774	2	3,880	4,263	113	1,578
12.0	less: Distribution Loss - Energy	10,436,542	4,345	10,432,197	44,308	3,897,897	404,574	3,111,184	362,234	1,708,925	259,005	549,277	0	12	37,468	41,168	1,097	15,244
12	less: Spinning Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Net Production Energy Less Loss & Ancillary	170,373,189	176,821	170,196,568	440,079	39,690,320	3,925,170	34,780,712	4,428,048	40,730,402	6,314,135	21,935,298	16,953,824	187	387,858	426,203	11,345	173,007
	Production Capacity Cost	663,491,147	616,451	662,874,896	2,329,086	191,040,535	22,887,037	168,718,232	18,410,564	128,334,980	22,175,928	55,253,878	48,972,788	899	2,176,558	3,117,488	55,834	401,115
	less: Other Revenue	(17,725,478)	(17,288)	(17,708,179)	(82,707)	(5,008,088)	(870,580)	(4,461,788)	(518,688)	(3,475,939)	(605,901)	(1,482,429)	(1,386,277)	(24)	(44,852)	(49,292)	(1,311)	(10,344)
	Net Production Capacity Cost	845,765,672	599,155	845,188,517	2,266,379	186,032,529	22,286,457	182,256,444	18,891,896	124,858,981	21,570,025	53,791,448	47,586,509	875	2,131,704	3,068,196	54,323	390,771
129	less: Transmission Loss - Demand	2,850,834	2,472	2,851,382	9,319	783,421	91,811	888,898	77,639	513,663	88,798	220,904	196,454	4	8,808	12,220	221	1,111
129	less: Distribution Loss - Demand	18,456,217	17,190	18,439,022	84,810	5,309,247	637,112	4,837,871	539,946	3,572,288	617,552	1,538,287	1,268,250	25	59,885	84,981	1,539	11,111
129	less: Reactive Power	4,021,675	3,746	4,017,929	14,123	1,158,804	138,829	1,010,831	117,856	778,416	334,762	297,711	5	13,045	18,518	335	2,427	
129	less: Regulation & Frequency Control	5,187,040	4,831	5,182,209	18,215	1,492,141	178,058	1,303,402	151,749	1,000,979	173,560	431,767	383,979	7	18,825	23,884	432	3,130
129	less: Operating Reserve Reserve	8,913,285	8,302	8,904,983	31,301	2,564,054	307,580	2,239,867	260,762	1,725,209	298,241	741,936	658,819	12	28,911	41,041	743	5,379
129	less: Operating Reserve Supplemental (Q 5)	9,887,219	9,209	9,878,010	34,721	2,844,229	341,309	2,488,818	289,255	1,913,723	330,830	823,008	731,912	13	32,821	45,328	824	5,982
	Total Net Retail Production Cost	596,846,427	550,405	596,093,021	2,093,887	171,902,502	20,570,852	149,912,978	17,454,888	115,351,675	19,926,477	49,702,785	43,950,379	808	1,972,379	2,042,027	50,228	381,127
	Generation Products & Schedule																	
12.4	add: Transmission Loss - Energy	1,829,714	1,825	1,828,089	4,589	403,637	41,897	352,474	43,895	372,502	58,683	191,802	148,774	2	3,880	4,263	113	1,578
12.4	add: Transmission Loss - Demand	2,850,834	2,472	2,851,108	7,472	857,784	88,725	570,974	71,478	608,584	95,500	312,331	242,265	3	8,318	8,943	185	2,570
12.0	add: Distribution Loss - Energy	10,436,542	4,345	10,432,197	44,308	3,897,897	404,574	3,111,184	362,234	1,708,925	259,005	549,277	0	12	37,468	41,168	1,097	15,244
12.0	add: Distribution Loss - Demand	18,456,217	7,684	18,448,528	78,358	6,092,774	715,457	5,501,808	640,583	3,022,101	458,030	971,353	14	21	68,258	77,807	1,940	28,957
	Ancillary Services																	
1	add: Reactive Intra Generation	4,021,675	3,746	4,017,929	14,123	1,158,804	138,829	1,010,831	117,856	778,416	134,567	334,762	297,711	5	13,045	18,518	335	2,427
1	add: Regulation & Frequency Control	5,187,040	5,087	5,181,978	14,594	1,758,089	188,454	1,408,109	135,991	1,107,318	194,914	518,796	426,677	7	2,979	3,274	87	3,854
1	add: Spinning Reserve	8,913,285	8,890	8,904,395	25,070	2,161,031	188,880	2,418,219	733,983	1,902,887	334,934	891,484	733,190	3	5,120	5,826	150	6,279
1	add: Reserve Supplemental (Q 5)	9,887,219	9,848	9,877,371	27,819	2,388,055	288,625	2,600,239	259,212	2,110,818	371,532	988,097	813,309	3	5,829	8,241	168	8,383
	Subtotal Generation Products	61,105,501	43,452	61,142,048	216,340	10,826,751	1,875,155	17,052,711	1,884,737	11,609,608	2,115,224	4,758,702	2,881,945	50	140,743	158,834	4,873	65,675
	Net Production Energy Less Loss & Ancillary	170,373,189	176,821	170,196,568	440,079	39,690,320	3,925,170	34,780,712	4,428,048	40,730,402	6,314,135	21,935,298	16,953,824	187	387,858	426,203	11,345	173,007
	Total Net Retail Production Cost	596,846,427	550,405	596,093,021	2,093,887	171,902,502	20,570,852	149,912,978	17,454,888	115,351,675	19,926,477	49,702,785	43,950,379	808	1,972,379	2,042,027	50,228	381,127
	Subtotal Generation Products	61,105,501	43,452	61,142,048	216,340	10,826,751	1,875,155	17,052,711	1,884,737	11,609,608	2,115,224	4,758,702	2,881,945	50	140,743	158,834	4,873	65,675
	Total Retail Production Cost	878,705,116	773,479	877,431,637	2,750,306	200,419,105	26,371,176	201,748,402	23,747,674	167,691,886	28,147,835	76,396,784	63,586,148	1,026	2,500,981	3,427,084	65,646	599,804
	add: Gross Receipts Tax	21,784,574	23,022	21,741,542	89,880	10,069,448	692,880	7,318,518	583,271	2,832,511	780,182	1,852,921	740,262	23	82,182	328,225	8,452	43,388
	Total Retail Production Cost W/ GRT	849,989,890	794,506	849,173,184	2,840,786	240,488,549	27,063,866	205,065,918	24,331,445	170,324,197	28,647,997	78,249,755	64,308,410	1,040	2,584,083	3,756,338	70,099	643,197
	Net Production Energy Less Loss & Ancillary	170,373,189	176,821	170,196,568	440,079	39,690,320	3,925,170	34,780,712	4,428,048	40,730,402	6,314,135	21,935,298	16,953,824	187	387,858	426,203	11,345	173,007
	Total Net Retail Production Cost	596,846,427	550,405	596,093,021	2,093,887	171,902,502	20,570,852	149,912,978	17,454,888	115,351,675	19,926,477	49,702,785	43,950,379	808	1,972,379	2,042,027	50,228	381,127
	Net Reactive Power, Reg - Freq. Ctrl & Spinning Res	18,121,888	17,505	18,104,425	52,788	4,578,885	438,388	4,872,958	487,238	2,788,681	684,414	1,745,042	1,452,578	10	21,144	22,418	522	12,381
	Total Basic Service	785,141,595	747,532	784,398,649	2,246,767	216,169,859	24,902,388	189,528,649	22,370,266	159,870,759	26,905,026	73,303,125	62,381,781	905	2,301,381	2,295,647	62,145	546,490
	Total Basic Service (\$/kWh)	0.0833	0.0504	0.0833	0.0785	0.0728	0.0807	0.0723	0.0881	0.0554	0.0591	0.0486	0.0519	0.0758	0.0837	0.1048	0.0747	0.0470

Exhibit JAL-1C
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COST OF SERVICE STUDY

Exhibit JAL - 1 (C)

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(1996)

Alloc #	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BS	BH	GRAM	GMH	GL	GLH	L	HVPS	AL	SE	SM	BH	TRAFFIC SIGNALS
Total Retail Production Cost																	
	580,170,055	832,457	878,343,598	2,939,212	244,707,617	28,457,031	210,582,737	25,240,804	177,862,388	29,978,344	80,755,055	68,753,667	1,127	2,892,414	3,684,055	70,720	610,923
	Production Energy (S01, S09, S18, S47, S55)	216,007	216,468,901	610,126	53,087,001	5,570,595	48,084,505	5,838,239	49,527,428	7,802,418	25,501,777	19,780,882	228	515,858	568,886	15,089	209,006
100	less: Off-System Sales	(33,975,902)	(33,942,748)	(120,196)	(9,589,265)	(1,189,517)	(8,552,282)	(984,175)	(8,662,737)	(1,161,381)	(2,803,161)	(2,657,193)	(47)	(95,972)	(94,483)	(2,513)	(18,827)
100	less: Transmission Off-System Sales Low Revenue	(269,562)	(269,293)	(54)	(26,180)	(8,438)	(12,853)	(7,068)	(52,882)	(8,214)	(22,240)	(21,082)	(0)	(182)	(250)	(20)	(152)
	Net Production Energy	182,439,444	182,591	182,258,854	468,877	43,991,857	4,371,040	38,244,370	4,834,177	42,811,829	6,631,822	22,476,377	17,102,607	181	429,204	471,634	12,556
12.4	less: Transmission Loss - Energy	1,029,714	1,025	1,028,089	4,509	403,637	41,897	352,474	43,895	372,502	58,683	191,802	148,774	2	3,880	4,763	113
12.6	less: Distribution Loss - Energy	10,436,542	4,345	10,432,197	44,308	3,897,697	404,574	3,111,184	382,234	1,708,925	259,005	549,277	8	12	37,466	41,168	1,097
12	less: Spinning Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Net Production Energy Less Loss & Ancillary	170,373,189	176,821	170,196,568	440,079	39,690,320	3,925,170	34,780,712	4,426,048	40,730,402	6,314,135	21,935,298	16,953,824	167	387,858	426,203	11,345
	Production Capacity Cost	683,481,147	616,451	682,874,696	2,329,086	191,040,535	22,887,037	168,718,232	19,410,584	128,334,960	22,175,928	55,252,878	48,972,786	899	7,176,558	3,117,488	55,634
	less: Other Revenue	(17,725,447)	(17,298)	(17,708,149)	(62,707)	(5,000,000)	(620,500)	(4,461,788)	(518,680)	(3,475,899)	(605,901)	(1,462,429)	(1,286,277)	(24)	(44,852)	(49,292)	(1,311)
	Net Production Capacity Cost	645,785,672	599,155	645,166,547	2,266,379	186,032,529	22,266,457	162,256,444	18,891,899	124,859,061	21,570,025	53,791,448	47,686,509	875	7,131,704	3,068,196	54,323
129	less: Transmission Loss - Demand	2,653,824	2,472	2,651,352	9,319	783,421	91,611	688,898	77,029	513,843	88,798	220,904	196,454	4	8,608	12,220	221
129	less: Distribution Loss - Demand	10,458,212	17,190	10,439,022	64,813	5,309,247	637,112	4,637,971	539,946	3,572,288	617,552	1,538,287	1,386,250	25	59,865	84,981	1,509
129	less: Reactive Power	4,021,875	3,748	4,017,929	14,123	1,156,904	138,829	1,010,631	117,856	778,418	134,567	334,762	297,711	5	13,045	18,518	335
129	less: Regulation & Frequency Control	5,187,040	5,067	5,181,978	14,594	1,258,069	109,454	1,408,109	135,991	1,107,378	194,914	518,756	426,877	2	2,979	3,274	87
129	less: Operating Spinning Reserve	8,913,265	8,698	8,904,963	25,078	2,161,831	188,080	2,418,219	233,603	1,902,887	334,934	691,484	733,190	3	5,120	5,626	156
129	less: Operating Reserve Supplemental (Q S 1)	9,887,219	9,208	9,877,521	24,721	2,844,228	241,309	2,680,239	258,212	2,118,818	371,532	988,832	813,308	3	5,629	6,241	168
	Total Net Retail Production Cost	598,646,427	553,405	598,093,021	2,093,887	171,902,532	20,570,852	149,912,978	17,454,888	115,251,675	19,926,477	49,702,785	43,950,379	608	1,972,378	2,842,027	56,228
Generation Products & Schedule																	
12.4	add: Transmission Loss - Energy	1,029,714	1,025	1,028,089	4,509	403,637	41,897	352,474	43,895	372,502	58,683	191,802	148,774	2	3,880	4,763	113
12.4	add: Transmission Loss - Demand	2,653,824	2,472	2,651,352	7,472	657,284	68,225	573,970	71,479	608,584	95,560	312,331	242,205	3	8,318	6,943	185
12.6	add: Distribution Loss - Energy	10,436,542	4,345	10,432,197	44,308	3,897,697	404,574	3,111,184	382,234	1,708,925	259,005	549,277	8	12	37,466	41,168	1,097
12.6	add: Distribution Loss - Demand	18,458,212	7,684	18,448,528	78,356	6,892,774	715,457	5,501,866	640,503	3,022,101	458,030	971,353	14	21	66,256	72,802	1,940
Ancillary Services																	
1	add: Reactive From Generation	4,021,875	3,748	4,017,929	14,123	1,156,904	138,829	1,010,631	117,856	778,418	134,567	334,762	297,711	5	13,045	18,518	335
1	add: Regulation & Frequency Control	5,187,040	5,067	5,181,978	14,594	1,258,069	109,454	1,408,109	135,991	1,107,378	194,914	518,756	426,877	2	2,979	3,274	87
1	add: Spinning Reserve	8,913,265	8,698	8,904,963	25,078	2,161,831	188,080	2,418,219	233,603	1,902,887	334,934	691,484	733,190	3	5,120	5,626	156
1	add: Reserve Supplemental (Q S 1)	9,887,219	9,208	9,877,521	24,721	2,844,228	241,309	2,680,239	258,212	2,118,818	371,532	988,832	813,308	3	5,629	6,241	168
	Subtotal Generation Products	61,165,501	49,452	61,142,048	216,340	18,828,251	1,875,155	17,052,711	1,864,737	11,609,608	1,907,224	4,758,702	2,861,945	50	140,743	158,834	4,073
	Net Production Energy Less Loss & Ancillary	170,373,189	176,821	170,196,568	440,079	39,690,320	3,925,170	34,780,712	4,426,048	40,730,402	6,314,135	21,935,298	16,953,824	167	387,858	426,203	11,345
	Total Net Retail Production Cost	598,646,427	553,405	598,093,021	2,093,887	171,902,532	20,570,852	149,912,978	17,454,888	115,251,675	19,926,477	49,702,785	43,950,379	608	1,972,378	2,842,027	56,228
	Subtotal Generation Products	61,165,501	49,452	61,142,048	216,340	18,828,251	1,875,155	17,052,711	1,864,737	11,609,608	1,907,224	4,758,702	2,861,945	50	140,743	158,834	4,073
	Total Retail Production Cost	679,205,116	773,479	677,431,837	2,750,306	230,419,105	26,371,176	201,746,402	23,747,674	167,891,886	28,147,895	76,398,784	63,586,148	1,026	2,500,981	3,427,064	65,648
	add: Gross Receipts Tax	21,284,574	23,022	21,281,242	83,980	10,089,444	682,650	3,918,516	583,221	2,832,511	780,182	1,852,921	240,282	23	83,102	329,225	4,453
	Total Retail Production Cost W/ GRT	649,989,090	798,506	649,173,104	2,840,286	240,488,549	27,063,826	205,665,918	24,331,445	170,324,197	28,847,997	78,249,755	64,306,410	1,048	2,584,083	3,756,338	70,099

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COST OF SERVICE STUDY

(1996)

Alloc #	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	BB/DM	QMH	QL	QLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
Transmission Cost	39,392,813	38,784	39,356,049	110,568	9,571,078	854,916	10,377,584	1,019,795	8,095,478	1,420,555	4,698,922	3,073,220	15	41,689	64,342	1,008	26,879
less: Off-System Revenues	(2,254,574)	(2,124)	(2,252,450)	(6,123)	(527,858)	(45,825)	(590,853)	(57,058)	(484,831)	(81,781)	(295,002)	(179,024)	(1)	(1,260)	(1,374)	(37)	(1,530)
less: Other Revenues	(6,246,853)	(5,864)	(6,240,989)	(16,868)	(1,462,581)	(127,245)	(1,637,104)	(158,095)	(1,287,375)	(226,596)	(817,375)	(496,031)	(2)	(3,484)	(3,800)	(101)	(4,248)
add: Gross Receipts Tax	867,691	818	866,723	3,581	661,418	27,818	358,268	23,273	384,951	27,913	23,873	29,512	1	3,313	13,127	128	1,730
Total Retail Transmission Cost	31,759,076	29,674	31,729,402	91,064	7,882,100	709,362	8,305,887	827,914	6,448,422	1,140,092	3,660,418	2,427,677	13	40,288	72,289	1,048	27,828
less: Dispatch Out Of Account 361	(828,838)	(809)	(827,827)	(2,331)	(200,978)	(17,485)	(224,828)	(21,725)	(176,905)	(31,138)	(82,878)	(88,182)	(0)	(478)	(523)	(14)	(584)
add: Scheduling Out Of Account 581	828,838	809	827,827	2,331	200,978	17,485	224,828	21,725	176,905	31,138	82,878	88,182	0	478	523	14	584
Total Transmission Cost With Products	31,759,076	29,674	31,729,402	91,064	7,882,100	709,362	8,305,887	827,914	6,448,422	1,140,092	3,660,418	2,427,677	13	40,288	72,289	1,048	27,828
Distribution Cost	254,358,451	74,216	254,284,236	948,181	111,136,157	8,861,597	60,552,564	6,786,676	31,038,210	4,497,491	14,241,249	5,901,998	378	3,140,648	6,907,191	51,071	216,847
less: Off-System Revenues	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less: Other Revenues	(14,108,307)	(4,118)	(14,104,188)	(50,463)	(5,443,784)	(480,974)	(3,584,237)	(433,903)	(2,003,088)	(308,630)	(875,568)	(128,998)	(20)	(210,327)	(472,457)	(3,308)	(10,372)
add: Gross Receipts Tax	12,521,512	14,308	12,507,208	55,301	8,255,287	438,242	2,435,888	362,875	1,635,888	438,985	1,151,181	459,837	14	51,828	204,568	2,762	28,555
Total Retail Distribution Cost	253,771,657	84,403	253,687,253	953,599	111,850,160	8,810,966	59,403,374	6,717,547	30,870,822	4,625,645	14,418,884	6,232,895	372	2,981,949	6,039,300	50,529	233,430
less: Cost. Changes for RS, RA, RH, GM, GMB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Distribution Cost	253,771,657	84,403	253,687,253	953,599	111,850,160	8,810,966	59,403,374	6,717,547	30,870,822	4,625,645	14,418,884	6,232,895	372	2,981,949	6,039,300	50,529	233,430
Retail Production Cost (\$ kWh)	0.0885	0.0622	0.0885	0.0839	0.0808	0.0876	0.0785	0.0741	0.0590	0.0634	0.0518	0.0535	0.0807	0.0903	0.1194	0.0838	0.0553
Base For Retail Rates																	
Transmission																	
Inactive Power	4,021,975	3,746	4,017,929	14,123	1,158,904	138,829	1,010,831	117,056	778,416	124,567	334,767	297,711	5	13,045	18,510	335	2,427
Regulation & Frequency Control	5,187,040	4,031	5,182,709	18,215	1,492,141	179,058	1,303,482	151,749	1,003,979	173,560	431,767	383,979	7	16,825	23,884	432	3,130
Operating Spinning Reserve	11,913,265	8,302	11,904,963	31,301	2,564,054	307,867	2,239,867	260,782	1,725,709	298,241	741,936	659,819	12	28,911	41,041	743	5,379
Gross Receipts Tax	481,735	497	481,738	2,078	228,207	16,267	89,024	89,024	55,071	15,054	36,553	15,351	1	1,907	7,762	101	817
Total Retail Transmission Cost	31,759,076	29,674	31,729,402	91,064	7,882,100	709,362	8,305,887	827,914	6,448,422	1,140,092	3,660,418	2,427,677	13	40,288	72,289	1,048	27,828
Total	50,362,792	47,050	50,315,742	156,781	13,423,406	1,351,203	12,948,891	1,371,120	10,011,097	1,761,514	5,705,437	3,784,537	39	100,977	163,493	2,659	34,582
Distribution																	
Loss Demand	18,456,212	17,190	18,439,022	64,813	5,309,247	637,112	4,637,971	539,946	3,572,298	817,552	1,538,287	1,388,250	25	59,865	84,981	1,539	11,139
Loss Energy	10,438,547	4,345	10,432,197	44,308	3,897,897	404,574	3,111,184	376,234	1,706,825	259,005	549,277	8	12	37,466	41,168	1,097	15,244
Gross Receipts Tax	795,901	634	795,766	3,563	403,039	27,888	151,485	27,198	82,918	21,762	50,537	15,805	1	3,158	11,734	175	1,972
Total Distribution Cost	253,771,657	84,403	253,687,253	953,599	111,850,160	8,810,966	59,403,374	6,717,547	30,870,822	4,625,645	14,418,884	6,232,895	372	2,981,949	6,039,300	50,529	233,430
Total	283,460,311	106,572	283,353,739	1,088,783	121,560,144	9,679,739	67,304,014	6,717,547	36,034,761	5,523,964	18,552,965	7,614,788	410	3,082,439	6,777,183	53,340	281,704
\$ kWh	0.0228	0.0083	0.0228	0.0315	0.0408	0.0320	0.0257	0.0233	0.0125	0.0121	0.0110	0.0083	0.0315	0.1077	0.2155	0.0637	0.0725

COST OF SERVICE STUDY

(1996)

Production COS Summary

Exhibit JAL - 1 (C)

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	Total Utility	FERC JURIS.	PA PUC JURIS.	RA	RS	RH	OS/DM	OMH	QL	QLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
Production Plant In Service	2,540,456,720	2,478,928	2,537,977,792	8,887,348	717,759,219	88,842,914	639,473,819	74,338,747	498,188,283	86,839,178	209,598,804	198,884,465	3,499	6,428,296	7,084,718	187,920	1,482,487
less Accumulated Depreciation	(1,147,480,150)	(1,119,741)	(1,148,380,389)	(4,056,937)	(324,079,084)	(40,141,870)	(288,718,978)	(33,588,587)	(225,135,020)	(39,230,048)	(94,793,551)	(89,787,455)	(1,579)	(2,903,033)	(3,180,441)	(84,865)	(870,941)
Net Production Plant	1,392,976,569	1,359,186	1,391,817,403	4,930,409	393,680,135	48,801,044	350,754,841	40,780,180	273,053,263	47,809,130	114,805,253	108,897,009	1,920	3,525,263	3,874,275	103,055	811,546
Additions To Net Production Plant Land/Plant Held For Future Use	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deductions To Net Production Plant ADIT	(255,524,503)	(248,336)	(255,275,187)	(803,988)	(72,183,738)	(8,946,066)	(84,319,838)	(7,478,847)	(50,108,830)	(8,734,488)	(21,081,890)	(19,984,103)	(352)	(648,572)	(710,584)	(18,901)	(149,112)
Production Rate Base	1,137,452,068	1,109,831	1,136,342,238	4,026,443	321,486,397	39,854,978	286,437,303	33,291,213	222,844,433	38,874,682	93,723,363	88,912,908	1,588	2,878,691	3,183,691	84,153	682,434
Adjustments To Production Rate Base Rate Base Adjusted For Rate-making Return on Rate Base	257,757,955 1,395,210,021 134,079,883	251,515 1,381,346 130,825	257,508,440 1,393,848,878 133,948,858	911,888 4,938,311 474,572	72,824,759 394,311,156 37,893,302	9,024,281 48,879,239 4,897,295	84,881,833 351,318,138 33,781,789	7,542,300 40,833,513 3,924,101	50,548,814 273,481,247 26,282,509	8,810,813 47,885,475 4,582,574	21,286,180 114,989,523 11,050,493	20,158,777 109,071,883 10,481,789	355 1,923 185	852,223 3,530,915 339,321	718,795 3,880,488 372,915	19,087 103,220 8,819	150,415 812,849 78,115
Production O & M Expense	434,393,221	428,804	433,984,417	1,387,828	114,578,579	13,033,117	101,057,302	12,188,723	92,777,388	15,275,551	44,087,268	37,031,839	523	1,084,173	1,189,481	31,119	343,451
Production Depreciation/Amortization	239,828,705	233,981	239,592,713	849,352	87,803,020	8,408,327	80,413,391	7,020,575	48,989,103	8,195,552	19,741,930	18,739,744	331	607,041	687,140	17,746	139,481
Taxes	71,876,447	38,837	71,837,810	247,383	24,432,715	2,318,892	18,350,275	2,135,405	11,813,380	1,924,867	5,895,965	2,500,296	89	881,880	1,474,839	11,939	49,898
Production Revenue Requirement	880,178,055	832,457	879,343,598	2,932,212	244,707,812	28,457,831	213,582,737	25,248,804	177,882,388	29,978,344	80,755,855	88,253,887	1,127	2,892,414	3,884,355	70,723	810,923
less Oil-System Sales Revenue	(34,245,484)	(33,416)	(34,212,048)	(121,150)	(9,875,425)	(1,198,954)	(8,820,135)	(1,002,062)	(8,715,599)	(11,70,598)	(2,825,401)	(2,878,275)	(47)	(86,854)	(95,233)	(2,533)	(19,884)
less Other Revenue	(12,725,478)	(12,288)	(12,708,179)	(62,702)	(5,008,008)	(820,580)	(4,481,788)	(518,888)	(3,475,989)	(605,801)	(1,462,429)	(1,388,277)	(24)	(4,852)	(49,292)	(1,311)	(10,344)
Total Retail Production Cost	828,205,118	781,745	827,423,371	2,755,355	230,024,188	26,838,097	200,500,814	23,728,073	181,870,790	28,201,847	76,487,825	84,889,118	1,056	2,560,909	3,539,829	88,878	580,595

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COST OF SERVICE STUDY
(1996)
Transmission COS Summary

Exhibit JAL - 1 (C)
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	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	BBGM	BBMH	QL	QLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
Transmission Plant In Service	319,052,035	300,545	318,751,491	868,546	74,898,884	8,498,928	83,813,495	8,074,583	85,751,458	11,573,153	41,746,825	25,334,295	82	178,808	194,401	5,172	216,971
less Accumulated Depreciation	(120,281,943)	(113,089)	(120,178,874)	(328,008)	(28,102,747)	(2,444,887)	(31,452,722)	(3,032,781)	(24,738,802)	(4,353,979)	(15,889,881)	(9,531,110)	(35)	(88,554)	(23,138)	(1,848)	(81,828)
Net Transmission Plant	198,760,093	187,476	198,572,617	540,538	46,596,138	4,053,843	52,180,773	5,038,801	41,014,856	7,219,174	25,776,964	15,803,185	58	110,351	121,285	3,228	135,344
Additions To Net Transmission Plant																	
Land/Plant Held For Future Use	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deductions To Net Transmission Plant																	
ADIT	(23,899,224)	(22,374)	(23,876,900)	(84,387)	(5,548,842)	(482,741)	(8,210,821)	(589,778)	(4,884,026)	(859,855)	(3,100,944)	(1,881,835)	(7)	(13,141)	(14,440)	(384)	(16,117)
Transmission Rate Base	175,080,869	185,151	174,895,718	476,172	41,047,496	3,571,202	45,949,953	4,437,022	38,130,830	6,359,519	22,876,020	13,921,351	51	97,211	108,824	2,842	119,227
Adjustments To Transmission Rate Base	(3,139,380)	(2,957)	(3,136,423)	(8,527)	(735,015)	(83,948)	(822,733)	(78,451)	(846,975)	(113,878)	(410,775)	(248,282)	(1)	(1,741)	(1,913)	(51)	(2,135)
Rate Base Adjusted For Rate-making	171,921,489	182,194	171,759,295	467,646	40,312,480	3,507,254	45,127,220	4,357,570	35,483,854	6,245,642	22,285,245	13,872,068	50	95,470	104,912	2,791	117,092
Return on Rate Base	18,521,655	15,587	18,508,068	44,841	3,874,029	337,047	4,338,728	418,783	3,409,898	800,208	2,139,690	1,313,886	5	9,175	10,082	268	11,252
Transmission O & M Expense	13,466,871	12,957	13,453,913	37,358	3,220,411	280,181	3,801,302	348,110	2,834,871	498,941	1,515,141	1,092,210	4	7,827	8,381	223	9,354
Transmission Depreciation/Amortization	8,594,368	6,232	8,588,138	17,989	1,548,887	134,783	1,733,028	167,435	1,383,431	239,983	844,917	525,336	2	3,888	4,031	107	4,499
Taxes	2,809,919	1,988	2,807,931	10,298	927,872	102,925	706,528	85,487	487,377	81,428	199,174	141,789	4	21,219	41,848	409	1,774
Transmission Revenue Requirement	39,392,813	30,784	39,356,049	110,588	9,571,029	854,918	10,377,584	1,018,785	8,085,478	1,420,555	4,898,822	3,073,220	15	41,889	84,342	1,008	28,829
less Off-System Sales Revenue	(2,254,574)	(2,124)	(2,252,450)	(8,123)	(527,858)	(45,925)	(580,853)	(57,059)	(484,831)	(81,781)	(295,007)	(179,024)	(1)	(1,250)	(1,374)	(37)	(1,533)
less Other Revenue	(8,248,853)	(5,884)	(8,240,969)	(18,868)	(1,482,581)	(127,245)	(1,637,104)	(158,095)	(1,287,325)	(228,588)	(812,375)	(498,031)	(2)	(3,484)	(3,808)	(101)	(4,248)
Total Retail Transmission Cost	30,891,385	28,756	30,862,829	87,477	7,560,880	681,742	8,148,827	804,641	6,343,471	1,112,178	3,588,546	2,398,165	13	36,975	59,182	870	21,098

COST OF SERVICE STUDY

(1996)

Distribution COS Summary

Exhibit JAL - 1 (C)

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	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BB	BB	QB/QM	QMH	QL	QLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
Distribution Plant In Service	1,341,646,934	391,641	1,341,255,293	4,798,858	517,881,488	45,738,804	340,847,482	41,253,080	190,484,233	29,178,404	92,772,857	12,287,288	1,801	20,001,345	44,928,857	314,587	988,322
less Accumulated Depreciation	(427,480,128)	(117,207)	(427,372,821)	(1,511,411)	(187,150,882)	(14,294,375)	(108,571,085)	(12,875,288)	(58,717,858)	(8,743,828)	(28,836,482)	(3,743,172)	(582)	(8,754,443)	(18,958,997)	(102,114)	(312,854)
Net Distribution Plant	914,156,806	274,434	913,882,372	3,287,446	350,530,628	31,444,429	234,276,407	28,577,814	133,766,575	20,434,575	65,936,195	8,524,094	1,309	11,246,902	24,969,860	212,473	673,468
Additions To Net Distribution Plant																	
Land/Plant Held For Future Use	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deductions To Net Distribution Plant																	
ADIT	(108,945,787)	(31,802)	(108,913,985)	(389,882)	(42,037,302)	(3,714,129)	(27,877,847)	(3,349,875)	(15,487,898)	(2,389,375)	(7,533,420)	(898,139)	(154)	(1,824,170)	(3,848,359)	(25,545)	(80,092)
Distribution Rate Base	805,211,019	242,631	804,968,388	2,897,565	308,493,524	27,730,300	206,598,560	25,227,939	118,298,679	18,065,201	58,402,775	7,527,955	1,155	9,822,732	21,321,501	186,928	593,378
Adjustments To Distribution Rate Base	(3,423,008)	(999)	(3,422,007)	(12,244)	(1,320,785)	(116,886)	(888,820)	(105,251)	(485,991)	(74,444)	(238,895)	(31,298)	(5)	(51,030)	(114,829)	(803)	(2,518)
Rate Base Adjusted For Rate-making	801,788,013	241,632	801,546,381	2,885,521	307,172,739	27,613,604	205,728,940	25,122,688	117,812,688	17,990,757	58,166,080	7,496,657	1,150	9,571,702	21,206,671	186,125	590,860
Return on Rate Base	77,051,878	23,221	77,028,607	277,299	29,519,300	2,653,887	19,770,551	2,414,290	11,321,799	1,728,912	5,589,760	720,429	110	919,841	2,037,980	17,887	58,000
Distribution O & M Expense	108,272,038	18,781	108,255,256	430,803	57,858,192	3,904,535	23,957,358	2,343,815	8,833,528	1,015,328	3,488,208	3,100,161	173	1,015,945	2,178,803	20,489	112,311
Distribution Depreciation/Amortization	42,910,032	12,332	42,897,699	148,830	15,972,088	1,429,271	10,202,401	1,288,818	6,001,875	917,571	2,948,905	393,559	81	1,088,050	2,488,127	10,071	31,477
Taxes	20,124,555	21,882	20,102,673	80,929	7,788,579	874,124	6,822,255	783,954	4,881,207	835,883	2,218,378	1,887,847	34	118,813	208,281	2,814	18,277
Distribution Revenue Requirement	254,358,451	74,218	254,283,239	948,181	111,138,157	8,881,537	60,552,584	8,788,878	31,038,210	4,497,491	14,241,249	5,801,898	378	3,140,848	8,907,191	51,071	218,847
less Off-System Sales Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less Other Revenue	(14,108,302)	(4,118)	(14,104,188)	(50,483)	(5,443,784)	(480,974)	(3,584,237)	(433,803)	(2,003,088)	(308,830)	(975,588)	(128,898)	(20)	(210,327)	(472,457)	(3,308)	(10,372)
Total Retail Distribution Cost	240,250,145	70,097	240,180,047	897,698	105,694,393	8,380,623	56,968,326	8,354,872	28,035,142	4,180,661	13,265,663	5,772,898	358	2,930,321	8,434,734	47,763	208,475

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Schedule D
Cost of Service
Table of Allocation Factors
(Pages 1-6)

COST OF SERVICE STUDY
(Allocation Table - 1996)

Allocator Number	Allocation Offset Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	TRAFFIC
Description	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BS	BU	BAIDM	QMB	AL	QLB	L	HVPS	AL	SE	SM	SH	SIGNALS	
* 12 CP (Coincident Peak - Monthly System Peak)	2,074,760	2,026	2,072,726	5,838	603,212	43,780	602,428	64,366	442,937	77,863	207,612	170,865	1	1,192	1,310	35	1,482	
1 Class Percentages (Based on 1998 Data)	100.000%	0.006%	99.902%	0.281%	24.264%	2.110%	27.106%	2.822%	21.349%	3.768%	10.002%	8.228%	0.000%	0.067%	0.083%	0.002%	0.070%	
1.5 1 CP (Coincident Peak - Annual System Peak)	2,483,000	2,582	2,480,438	8,788	633,047	40,872	709,284	43,379	628,403	84,041	224,273	186,789	0	0	0	0	1,482	
2 Class Percentages (Based on 1998 Data)	100.000%	0.104%	99.898%	0.357%	26.702%	1.864%	28.789%	1.781%	21.464%	3.412%	9.106%	7.584%	0.000%	0.000%	0.000%	0.000%	0.059%	
* NCP (Class Customer Peaks)	3,012,818	2,787	3,009,831	10,528	830,178	108,177	804,703	102,770	673,780	97,314	233,523	231,189	4	7,150	7,858	209	1,482	
3 Class Percentages (Based on 1998 Data)	100.000%	0.093%	99.907%	0.349%	27.557%	3.824%	26.711%	3.411%	19.048%	3.230%	7.751%	7.673%	0.000%	0.237%	0.261%	0.007%	0.089%	
* MDD (Non-Coincidental - Individual Customer Peak)	5,107,839	2,787	5,105,052	18,888	2,323,187	129,235	1,037,358	143,866	759,480	119,728	286,444	270,408	4	7,150	7,858	209	1,482	
4 Class Percentages (Based on 1998 Data)	100.000%	0.055%	99.945%	0.370%	45.483%	2.530%	20.309%	2.813%	14.869%	2.344%	5.608%	5.284%	0.000%	0.140%	0.154%	0.004%	0.090%	
* Class Max @ Gen. Level - Subtransmission (D20C)	2,708,886	2,787	2,704,109	10,528	830,178	108,177	804,703	102,771	658,485	97,314	174,294	0	4	7,150	7,858	209	1,482	
6 Class Percentages (Based on 1998 Data)	100.000%	0.103%	99.897%	0.389%	30.689%	4.033%	28.728%	3.797%	20.631%	3.585%	8.439%	0.000%	0.000%	0.284%	0.290%	0.008%	0.054%	
* Class Max @ Gen. Level - Network (D21C)	205,400	0	205,400	0	0	0	41,876	7,886	112,971	18,878	23,811	0	0	0	0	0	0	
7 Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.000%	0.000%	0.000%	20.388%	3.830%	55.000%	9.190%	11.593%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
* Class Max @ Gen. Level - Subtrans/Network Total (D30C)	1,784,001	0	1,784,001	10,528	830,178	108,177	870,838	75,517	48,416	4,888	0	0	4	7,150	7,858	209	1,482	
8 Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.597%	47.082%	8.189%	38.029%	4.281%	2.831%	0.285%	0.000%	0.000%	0.000%	0.405%	0.445%	0.012%	0.083%	
* Class Max @ Gen. Level - Secondary Loss Series (D31C)	1,784,001	0	1,784,001	10,528	830,178	108,177	870,838	75,517	48,416	4,888	0	0	4	7,150	7,858	209	1,482	
9 Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.597%	47.002%	8.189%	38.029%	4.281%	2.831%	0.285%	0.000%	0.000%	0.000%	0.405%	0.445%	0.012%	0.083%	
# of Hours	8,760																	
mVh at Customer Meter Level (Based on 1998 Data)	12,408,325	12,808	12,393,517	33,848	2,977,208	309,038	2,821,147	326,258	2,884,887	455,220	1,508,474	1,201,824	13	28,818	31,448	837	11,838	
Total Loss		1,034		1,105	1,105	1,105	1,098	1,060	1,052	1,051	1,038	1,009	1,077	1,105	1,105	1,105	1,105	
Transmission Loss		1,009		1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	1,009	
Distribution Loss		1,025		1,095	1,095	1,095	1,088	1,060	1,043	1,041	1,028	1,000	1,087	1,095	1,095	1,095	1,095	
* MWHS at Generation Level (Based on 1998 Data)	13,283,584	13,242	13,270,342	37,403	3,289,890	341,498	2,872,987	357,783	3,038,214	478,317	1,583,363	1,212,841	14	31,824	34,751	925	12,882	
12 MWHS at Input Factor	100.000%	0.100%	99.900%	0.282%	24.787%	2.571%	21.828%	2.893%	22.857%	3.601%	11.788%	9.129%	0.000%	0.238%	0.262%	0.007%	0.087%	
Total Loss	877,258	434	876,826	3,555	312,722	32,460	261,820	29,627	161,327	23,097	53,879	10,817	1	3,008	3,303	88	1,223	
12.2 Total Loss Factor	100.000%	0.049%	99.951%	0.406%	35.848%	3.700%	28.705%	3.388%	17.250%	2.633%	6.142%	1.233%	0.000%	0.343%	0.377%	0.010%	0.139%	
Transmission Loss	118,408	118	118,388	334	28,348	3,048	25,826	3,181	27,082	4,288	13,945	10,816	0	287	310	8	115	

COST OF SERVICE STUDY
(Allocation Table - 1996)

Allocator Number	Description	Total Utility	FERC JURISL.	PA PUC JURISL.	BA	BS	RH	OR/OM	OMH	OL	OLH	L	HVES	AL	SE	EM	EH	TRAFFIC SIGNALS
12.4	Transmission Loss Factor	100.000%	0.100%	99.900%	0.282%	24.787%	2.571%	21.628%	2.893%	22.857%	3.801%	11.789%	9.129%	0.000%	0.238%	0.282%	0.007%	0.097%
	Distribution Loss Factor	758,773	316	758,457	3,221	283,378	29,414	228,194	28,338	124,245	18,831	39,934	1	1	2,724	2,893	80	1,108
12.6	Distribution Loss	100.000%	0.042%	99.958%	0.425%	37.347%	3.877%	29.810%	3.471%	18.374%	2.482%	5.283%	0.000%	0.000%	0.358%	0.394%	0.011%	0.148%
	* Average Customers (Based on 1996 Data)	579,740	1	579,739	2,793	498,280	22,729	51,379	3,357	839	109	28	3	2	1	717	14	1,893
13	Customer Factor - P311/P304	100.000%	0.000%	100.000%	0.482%	85.804%	3.921%	8.882%	0.579%	0.110%	0.018%	0.004%	0.001%	0.000%	0.000%	0.124%	0.002%	0.292%
	* Total Number Of Customers (C10)	580,730	1	580,729	2,834	498,925	22,815	51,592	3,372	839	107	28	3	2	1	709	14	1,890
14	Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.489%	85.509%	3.929%	8.884%	0.581%	0.110%	0.018%	0.004%	0.001%	0.000%	0.000%	0.122%	0.002%	0.291%
	* Total Number Of Network Customers (C21)	1,190	0	1,190	0	0	0	928	173	76	8	3	0	0	0	0	0	0
15	Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.000%	0.000%	0.000%	77.983%	14.538%	8.555%	0.872%	0.252%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
	* Total Number Of SubTrans/Network Customers (C30)	878,510	1	878,509	2,834	498,925	22,816	51,590	3,372	833	107	19	0	2	39,061	58,858	813	1,890
18	Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.418%	73.230%	3.383%	7.803%	0.497%	0.093%	0.018%	0.003%	0.000%	0.000%	5.755%	8.845%	0.120%	0.248%
	* Total Number Of Secondary less series Customers (C31)	637,240	1	637,239	2,834	498,925	22,816	50,283	3,130	99	10	0	0	2	0	58,858	813	1,890
17	Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.445%	77.891%	3.580%	7.888%	0.491%	0.018%	0.002%	0.000%	0.000%	0.000%	0.000%	9.205%	0.128%	0.285%
	* Total Number Of Secondary less St. Ltg. Customers (C32)	578,077	1	578,076	2,834	498,925	22,816	50,283	3,130	99	10	0	0	0	0	0	0	0
18	Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.492%	86.200%	3.980%	8.725%	0.543%	0.017%	0.002%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
	* Direct - Street Lighting Account 373 (CXP1)	\$21,788,039		\$21,788,039											8,532,484	15,253,555		
19	Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	79.985%	70.015%	0.000%	0.000%
	* Direct - Install On Cust. Premises Account 371 (CXP2)	\$37,793		\$37,793				4,584		13,825		2,218	17,188		0.000%	0.000%	0.000%	0.000%
20	Class Percentages (Based on 1998 Data)	100.000%	0.000%	100.000%	0.000%	0.000%	0.000%	12.078%	0.000%	38.581%	0.000%	5.888%	45.474%	0.000%	0.000%	0.000%	0.000%	0.000%
	* Gross Receipts Allocator	\$810,280,857	\$57,283	\$809,423,574	\$3,348,885	\$74,878,804	\$26,788,406	\$145,021,021	\$21,733,422	\$98,000,872	\$28,068,583	\$89,984,893	\$27,559,481	\$41	\$3,093,842	\$12,258,877	\$185,787	\$1,815,280
21	Class Percentages (Based on 1998 Data)	100.000%	0.100%	99.894%	0.413%	48.205%	3.183%	18.009%	2.682%	12.095%	3.217%	8.514%	3.401%	0.000%	0.382%	1.513%	0.020%	0.199%
	D10 Changes To NCP Percent		4.978%		4.405%	4.405%	0.584%	-3.777%	-13.251%	0.114%	4.783%	-0.924%	-0.924%	7.478%	7.478%	7.478%	7.478%	7.478%
	* D10 Allocator	3,008,858	2,928	3,005,731	10,890	888,745	109,793	774,309	89,152	574,444	101,989	231,385	229,033	4	7,885	8,448	226	1,571
32	D10 Allocator From NCP	100.000%	0.097%	99.903%	0.365%	28.800%	3.849%	25.738%	2.983%	19.093%	3.389%	7.890%	7.812%	0.000%	0.255%	0.281%	0.007%	0.052%

COST OF SERVICE STUDY
(Allocation Table - 1996)

Allocator Number	Description	Allocator Offset Number																TRAFFIC SIGNALS
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	
	Total Utility	FERC JURIS.	PA PUC JURIS.	BA	BE	BH	OS/OM	OMH	OL	OLH	L	HVPS	AL	SE	EM	SH		
	Customer maintenance and service cost	1,000		1,000	1,000	1,000	3,227	3,380	9,692	9,154	17,802	26,298	0,000	0,000	0,000	0,000	0,000	
	* Customer Service Costs	708,599	1	708,599	2,783	498,280	22,729	185,820	11,281	6,187	976	483	78	0	0	0	0	
38	Customer Service Factor	100.000%	0.000%	100.000%	0.385%	70.235%	3.217%	23.487%	1.598%	0.878%	0.137%	0.088%	0.011%	0.000%	0.000%	0.000%	0.000%	
	* Weighted Customer Meters Investment (CW1)	1,167,809	100	1,167,809	2,934	498,925	72,915	638,820	37,345	61,840	9,290	7,800	1,920	0	0	0	0	
40	Customer Meter Investment Factor	100.000%	0.000%	99.991%	0.243%	42.558%	1.854%	45.873%	3.198%	4.440%	0.798%	0.688%	0.164%	0.000%	0.000%	0.000%	0.000%	
	* Transmission Plant Account Direct Assignment (P3502A)	114,448	0	114,448	0	0	0	15,247	0	0	0	99,201	0	0	0	0	0	
60	Class Percentages (Based On 1992 COSS)	100.000%	0.000%	100.000%	0.000%	0.000%	0.000%	13.322%	0.000%	0.000%	0.000%	88.878%	0.000%	0.000%	0.000%	0.000%	0.000%	
	* Transmission Plant Account Direct Assignment (P3523D)	2,398,001	0	2,398,001	0	0	0	0	0	0	0	2,398,001	0	0	0	0	0	
81	Class Percentages (Based On 1992 COSS)	100.000%	0.000%	100.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	100.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
	* Transmission Plant Account Direct Assignment (P3546A)	6,585,083	0	6,585,083	0	0	0	97,389	0	0	0	8,487,874	0	0	0	0	0	
82	Class Percentages (Based On 1992 COSS)	100.000%	0.000%	100.000%	0.000%	0.000%	0.000%	1.477%	0.000%	0.000%	0.000%	98.523%	0.000%	0.000%	0.000%	0.000%	0.000%	
	* Distribution Plant Account Direct Assignment (P382A)	43,288,968	0	43,288,968	0	180,901	0	2,744,834	17,328	10,918,019	189,847	29,240,137	0	0	0	0	0	
83	Class Percentages (Based On 1992 COSS)	100.000%	0.000%	100.000%	0.000%	0.418%	0.000%	6.343%	0.040%	25.228%	0.393%	67.578%	0.000%	0.000%	0.000%	0.000%	0.000%	
	* Distribution Plant Account Direct Assignment (P388A)	13,892,831	0	13,892,831	0	1,081,921	114,455	3,528,887	872,144	8,197,877	1,299,847	0	0	0	0	0	0	
84	Class Percentages (Based On 1992 COSS)	100.000%	0.000%	100.000%	0.000%	13.548%	0.824%	25.385%	6.278%	44.611%	9.357%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
CALCULATED ALLOCATORS																		
	* Sum Production Plant	2,368,398,721	2,309,085	2,364,089,636	8,371,583	668,582,339	82,849,039	695,680,714	69,243,608	484,055,188	80,889,437	185,238,257	185,071,708	3,259	5,987,865	8,580,881	175,045	
100	Production Plant Factor	100.000%	0.098%	99.902%	0.354%	28.253%	3.501%	29.172%	2.028%	19.610%	3.418%	8.250%	7.821%	0.000%	0.253%	0.270%	0.007%	
	* Sum Transmission Plant	312,168,756	294,079	311,892,678	847,900	73,091,533	8,359,087	81,614,322	7,900,818	64,338,835	11,324,125	40,848,332	24,789,158	90	173,098	190,218	6,081	
101	Transmission Plant Factor	100.000%	0.004%	99.998%	0.272%	23.413%	2.037%	26.207%	2.531%	20.808%	3.627%	13.069%	7.940%	0.000%	0.055%	0.081%	0.002%	
	* Sum Distribution Plant	1,733,225,730	359,892	1,732,865,738	4,411,052	476,848,589	42,042,559	313,302,918	37,918,335	175,080,817	28,820,438	85,275,511	11,275,923	1,748	18,384,998	41,298,065	289,185	
102	Distribution Plant Factor	100.000%	0.029%	99.971%	0.358%	38.588%	3.408%	25.405%	3.075%	14.188%	2.175%	8.915%	0.914%	0.000%	1.481%	3.349%	0.074%	
	* Sum Prod, Trans, Dist Plant	3,911,811,207	2,963,155	3,908,848,052	13,630,535	1,217,520,471	131,250,885	890,777,951	115,063,757	703,482,838	119,034,000	321,382,100	221,138,789	5,098	24,545,960	48,068,964	469,271	

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COST OF SERVICE STUDY
(Allocation Table - 1996)

Allocator Offset Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	
Allocator Number	Total Liability	FERC JURIS.	PA PUC JURIS.	EA	ER	EM	OE/OM	OMH	OL	OLM	L	HVPA	AL	EE	EM	EH	TRAFFIC SIGNALS
103 Prod,Trans,Dist Plant Factor	100.000%	0.078%	99.924%	0.348%	31.174%	3.355%	26.328%	2.841%	17.984%	3.043%	8.215%	5.653%	0.000%	0.827%	1.729%	0.012%	0.084%
* Sum Production O&M Expense	341,891,807	337,305	341,354,802	1,075,859	90,110,353	10,247,344	78,474,290	9,589,180	72,893,846	12,018,559	34,870,988	28,135,351	411	837,002	919,814	24,478	270,342
104 Production O&M Factor	100.000%	0.099%	99.901%	0.315%	28.372%	2.999%	23.258%	2.801%	21.382%	3.617%	10.148%	8.527%	0.000%	0.245%	0.289%	0.007%	0.079%
* Total Power Expense	32,851,833	32,542	32,819,391	92,215	8,100,353	842,984	7,076,504	880,345	7,450,792	1,175,038	3,829,381	2,975,747	35	77,791	85,483	2,275	31,488
105 Total Power Expense Factor	100.000%	0.100%	99.900%	0.282%	24.808%	2.582%	21.689%	2.698%	22.819%	3.599%	11.728%	9.114%	0.000%	0.238%	0.282%	0.007%	0.088%
* Sum Transmission O&M Expense	11,112,079	10,702	11,101,377	30,857	2,859,851	231,420	2,974,410	287,527	2,341,342	412,108	1,240,499	892,128	3	8,299	8,927	194	7,728
108 Transmission O&M Factor	100.000%	0.098%	99.904%	0.278%	23.937%	2.983%	28.787%	2.588%	21.070%	3.709%	11.184%	8.118%	0.000%	0.057%	0.082%	0.002%	0.070%
* Sum Distribution O&M Expense	38,801,510	9,031	38,592,479	148,425	15,498,837	1,419,441	9,885,590	1,041,431	4,700,880	504,223	1,821,942	1,934,383	83	675,508	1,212,155	11,541	34,128
107 Distribution O&M Factor	100.000%	0.073%	99.977%	0.379%	40.145%	3.877%	25.001%	2.898%	17.199%	1.388%	4.720%	5.011%	0.000%	1.491%	3.140%	0.030%	0.081%
* Total Net Plant	2,117,723,954	1,517,813	2,116,206,341	7,400,380	871,027,418	71,158,478	538,986,818	62,958,173	377,373,942	83,289,382	174,802,157	110,382,211	2,773	12,598,836	24,682,018	273,923	1,376,037
110 Total Revenue Factor	100.000%	0.072%	99.928%	0.349%	31.888%	3.380%	25.451%	2.973%	17.820%	2.889%	8.254%	5.211%	0.000%	0.585%	1.181%	0.013%	0.095%
Steam Production Plant Accts. 311-318 Rate (P3118)	832,093,588	813,031	831,280,557	2,900,383	233,290,518	29,851,181	207,819,281	24,227,731	164,853,881	26,537,429	70,470,511	65,762,785	1,129	2,097,788	2,305,438	81,327	505,469
112 Sum of Account 311-318 Factor	100.000%	0.098%	99.902%	0.349%	28.037%	3.443%	24.051%	2.812%	19.812%	3.430%	8.489%	7.802%	0.000%	0.252%	0.277%	0.007%	0.081%
Nuclear Production Plant Accts. 321-325 Rate (P3215)	1,482,781,041	1,445,883	1,481,315,158	5,778,803	420,522,824	52,338,272	374,857,389	43,493,872	288,285,055	50,800,899	120,723,237	115,385,117	2,057	3,768,788	4,130,932	109,880	847,853
113 Sum of Account 321-325 Factor	100.000%	0.098%	99.902%	0.358%	28.381%	3.530%	25.281%	2.833%	19.510%	3.413%	8.142%	7.780%	0.000%	0.253%	0.278%	0.007%	0.057%
Other Production Plant Accts. 341-348 Rate (P3418)	42,505,725	41,382	42,464,343	153,803	12,185,190	1,529,776	10,857,945	1,254,180	8,190,171	1,444,783	3,349,480	3,205,783	60	108,225	118,941	3,104	23,083
114 Sum of Account 341-348 Factor	100.000%	0.097%	99.903%	0.381%	28.620%	3.589%	25.545%	2.951%	19.788%	3.399%	7.880%	7.883%	0.000%	0.255%	0.280%	0.007%	0.054%
Transmission Plant Accounts 352-353 Rate (P3523)	132,931,400	128,231	132,805,176	383,955	31,374,008	2,729,592	35,085,858	3,391,308	27,818,032	4,880,788	18,513,208	10,840,505	39	74,302	81,850	2,172	81,129
116 Sum of Account 352-353 Factor	100.000%	0.095%	99.906%	0.274%	23.002%	2.953%	28.379%	2.551%	20.775%	3.657%	12.423%	8.005%	0.000%	0.058%	0.081%	0.002%	0.068%
Transmission Plant Accounts 354-356 Rate (P3546)	116,281,825	108,497	116,155,128	307,058	28,489,344	2,302,878	29,889,311	2,881,199	23,298,848	4,100,915	17,938,117	8,977,138	33	62,888	68,885	1,833	78,883
117 Sum of Account 354-356 Factor	100.000%	0.092%	99.908%	0.284%	22.787%	1.881%	25.537%	2.481%	20.040%	3.527%	15.429%	7.721%	0.000%	0.054%	0.059%	0.002%	0.088%
Distribution Plant Accounts 381-382 Rate (P3812)	359,045,878	180,074	358,885,802	1,238,874	97,974,483	12,721,887	93,317,744	10,784,481	84,584,882	6,328,851	80,757,837	8,843,227	474	991,105	1,188,182	24,788	173,380
118 Sum of Account 381-382 Factor	100.000%	0.050%	99.950%	0.345%	27.287%	3.543%	25.990%	2.998%	17.882%	2.319%	18.922%	1,908%	0.000%	0.288%	0.333%	0.007%	0.048%
Distribution Plant Accounts 384-385 Rate (P3845)	388,959,883	77,246	388,882,437	1,834,178	207,881,577	17,503,358	90,876,197	9,974,807	19,457,812	3,101,042	4,819,450	0	910	8,892,131	20,998,404	211,345	554,428

COST OF SERVICE STUDY
(Allocation Table - 1996)

Allocator Offset Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	
Allocator Number	Total Utility	FERC JURIS.	PA PUC JURIS.	RA	RB	RB	GRDM	GMH	QL	QLH	L	HVPS	AL	RE	EM	SH	TRAFFIC SIGNALS
119 Sum of Account 364-365 Factor	100.000%	0.020%	99.980%	0.474%	50.717%	4.523%	23.433%	2.578%	6.028%	0.801%	1.245%	0.000%	0.000%	2.558%	6.428%	0.055%	0.143%
Distribution Plant Accounts 364-367 Ratio (P3667)	187,377,878	49,591	187,328,287	410,587	38,090,982	4,189,172	59,885,832	9,387,321	54,559,542	9,038,888	12,081,801	0	169	557,887	1,073,730	18,470	74,818
120 Sum of Account 368-367 Factor	100.000%	0.028%	99.974%	0.219%	19.281%	2.225%	31.949%	6.010%	29.117%	4.824%	8.448%	0.000%	0.000%	0.288%	0.673%	0.010%	0.040%
Distribution Plant Accounts 368 Ratio (P368)	150,046,402	37,381	150,009,041	471,443	60,484,733	3,933,198	32,529,400	4,828,713	30,825,432	5,395,889	8,215,374	3,821,588	168	177,747	2,219,858	33,263	94,888
121 Sum of Account 368 Factor	100.000%	0.025%	99.975%	0.312%	40.057%	2.808%	21.550%	3.284%	20.421%	3.676%	4.118%	2.389%	0.000%	0.118%	1.470%	0.027%	0.063%
Distribution Plant Accounts 369 Ratio (P369)	57,792,430	8,956	57,783,476	288,907	44,712,331	2,108,548	8,502,453	800,028	1,881,770	298,222	708,814	887,240	10	17,843	18,390	518	3,808
122 Sum of Account 369 Factor	100.000%	0.012%	99.988%	0.465%	77.387%	3.848%	11.261%	1.038%	3.258%	0.613%	1.223%	1.155%	0.000%	0.031%	0.034%	0.001%	0.000%
Total General Plant Production	147,528,897	143,958	147,384,941	521,911	41,881,670	5,185,076	37,135,402	4,318,889	28,830,691	5,042,907	12,171,780	11,537,985	203	373,303	410,281	10,913	88,000
123 Sum of General Plant Production	100.000%	0.098%	99.902%	0.354%	28.263%	3.501%	26.172%	2.928%	19.810%	3.418%	8.250%	7.821%	0.000%	0.253%	0.278%	0.007%	0.058%
Total General Plant Transmission	5,818,908	5,481	5,813,425	16,804	1,382,388	118,528	1,524,852	147,285	1,199,182	211,072	781,380	482,050	2	3,228	3,648	94	3,957
124 Sum of General Plant Transmission	100.000%	0.094%	99.906%	0.272%	23.413%	2.007%	26.207%	2.531%	20.808%	3.827%	13.085%	7.940%	0.000%	0.055%	0.081%	0.007%	0.088%
Total General Plant Distribution	91,808,165	28,825	91,836,990	378,698	35,458,812	3,132,881	23,348,381	2,825,831	13,047,224	1,998,576	8,354,486	640,247	130	1,369,993	3,077,404	21,548	67,568
125 Sum of General Plant Distribution	100.000%	0.029%	99.971%	0.358%	38.588%	3.409%	26.405%	3.075%	14.198%	2.175%	8.815%	0.914%	0.000%	1.491%	3.349%	0.023%	0.074%
Total Net Production	1,137,452,068	1,100,831	1,136,342,238	4,078,443	321,488,397	39,854,978	288,437,309	33,281,713	222,844,433	38,874,882	93,723,383	98,812,908	1,588	2,878,881	3,183,691	84,163	882,434
126 Sum of Production	100.000%	0.098%	99.902%	0.354%	28.284%	3.504%	25.182%	2.827%	19.800%	3.418%	8.240%	7.817%	0.000%	0.253%	0.278%	0.007%	0.058%
Total Net Transmission	175,060,889	165,151	174,895,738	478,172	41,047,498	3,571,202	45,949,853	4,437,022	36,130,830	6,358,519	27,878,020	13,821,351	51	87,211	108,824	2,042	119,277
127 Sum of Transmission	100.000%	0.094%	99.906%	0.272%	23.448%	2.040%	26.248%	2.535%	20.839%	3.833%	17.953%	7.952%	0.000%	0.058%	0.001%	0.007%	0.088%
Total Net Distribution	695,211,019	242,831	694,968,188	2,897,285	308,493,524	27,730,300	208,598,580	25,227,939	118,298,879	18,085,201	58,402,775	7,527,955	1,155	9,872,732	21,371,501	188,928	503,328
128 Sum of Distribution	100.000%	0.030%	99.970%	0.360%	38.312%	3.444%	25.858%	3.133%	14.092%	2.244%	7.253%	0.935%	0.000%	1.195%	2.848%	0.023%	0.074%
Non-Fuel Power Production + Expenses	697,738,811	649,887	697,088,924	2,450,238	200,715,880	24,085,981	175,338,388	20,412,827	135,050,559	23,348,522	58,079,278	51,651,081	948	2,283,210	3,212,721	58,187	421,089
129 Production less (ECh) Fuel Related Costs Allocator	100.000%	0.093%	99.907%	0.351%	28.787%	3.452%	26.130%	2.928%	19.358%	3.348%	8.324%	7.403%	0.000%	0.326%	0.480%	0.000%	0.060%
Average demand	1,518	50.33%															
Peak demand	3,013																

COST OF SERVICE STUDY
(Allocation Table - 1996)

Allocator Number	Allocator Offset Number	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Description	Total Units	FERC JURIS.	PA PUC JURIS.	BA	BE	BH	ORIDM	RMH	OL	OLM	L	HVFA	AL	SE	EM	EH	TRAFFIC SIGNALS
Actual Revenue 1986 (FERC P304, P311)	\$1,086,606,920	1057,283	\$1,086,849,837	\$3,349,885	\$374,878,804	\$25,788,406	\$274,794,288	\$27,070,832	\$201,573,273	\$29,104,678	182,353,486	\$49,801,005	\$1,323	\$3,093,842	\$12,258,677	\$186,787	\$1,816,290

Exhibit JAL-1D
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Schedule E

**Derivation of Production
Based on Ancillary Services
(Pages 1-2)**

DERIVATION OF PRODUCTION BASED ANCILLARY SERVICES

		Total	Fossil Steam	Nuclear	Combustion Turbine
Revenue Requirement by Fuel	a/	679,777,573	219,559,623	452,668,508	7,549,442
MW of Capacity		2,522	1,809	659	54
Ancillary Services					
Reactive from Generation	b/				
allocated to type of production by net plant	c/	4,021,675	1,342,054	2,604,821	74,800
Regulation and Frequency Response					
43 MW from 1809 MW fr. steam		5,187,040	5,187,040		
revenue requirement					
Operating Reserves-Spinning					
73.9 MW from balance of Steam	d/	8,913,265	8,913,265		
Operating Reserves-Supp. (Q.S.)	e/				
54 MW from BI; 20 MW balance from Steam		9,887,219	2,412,577		7,474,642
Capacity Losses					
Transmission					
22 MW from balance of Steam	f/	2,653,834	2,653,834		
Distribution					
153 MW from balance of Steam	g/	18,456,212	18,456,212		
Total Production Capacity Based Ancillary Services & Losses Costs		49,119,245	38,964,982	2,604,821	7,549,442

a/ functionalized based on data presented in Mr. Clayton's testimony.

b/ Proportion of total plant investment derived from investment in facilities at each plant related to production of reactive power and power factor; proportion applied to total revenue requirement as described in testimony.

c/ Net plant:

Gross Book	2,366,398,721	840,120,348	1,483,378,944	42,899,429
Accum. Dep	1,081,527,382	411,352,041	651,173,531	19,001,810
Net Book	1,284,871,339	428,768,307	832,205,413	23,897,619
Percentage	100.00%	33.37%	64.77%	1.86%

d/ e/ 3% ECAR Requirement for each spinning and/or quick start * 1996 peak of 2463 MW;

f/ Transmission Loss Factor minus one—(1.009-1) * 1996 peak of 2463;

g/ (Total Loss Factor minus one—(1.071-1) * 2463 MW) less 22 MW transm loss;

DERIVATION OF NON FUEL PRODUCTION COSTS

1 Total Production Cost	880,176,055	
2 less Other Rev	17,725,476	
3 <u>Total Retail Prod Cost incl. fuel</u>	<u>862,450,579</u>	(1)-(2)
Fuel Portion of Production Cost		
4 Fuel (ECR Rider 15)		
5 Acct 501 Fuel	156,405,163	
6 acct 509 allowances	2,068,025	
7 Acct 518 Nuclear Fuel	25,704,809	
8 Acct 521 Steam Exp	0	
9 Acct 547 Fuel	201,637	
10 <u>Acct 555 Purch Pwr</u>	<u>32,269,274</u>	
11 <u>Subtotal</u>	<u>216,648,908</u>	Sum (4)-(10)
12 less Off System Rev.	33,975,902	
13 <u>Total Net Fuel</u>	<u>182,673,006</u>	(11)-(12)
14 Production Cost excl. Net Fuel	679,777,573	(3)-(13)

Ex. ____ (PAW-1)
Page 1 of 22

1
2
3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

4

Duquesne Light Company) Docket No. ER96-1573-000

5
6
7

SUPPLEMENTAL DIRECT TESTIMONY
OF
PETER A. WYBIERALA

8

Q: Please state your name and business address.

9

A. My name is Peter A. Wybierala and my business ad-

10

dress is 411 Seventh Avenue, Pittsburgh, Pennsylva-

11

nia 15230-1930.

12

Q. By whom are you employed and in what capacity?

13

A. I am employed by Duquesne Light Company ("Duquesne")

14

as Supervisor, Business Planning Department, Regula-

15

tory and Economic Analysis Unit.

16

Q. On whose behalf are you testifying?

17

A. I am testifying on behalf of Duquesne.

18

Q. Mr. Wybierala are you responsible for the develop-

19

ment of the Ancillary Service charges?

20

A. Yes.

Ex. ____ (PAW-1)
Page 2 of 22

1 Q. What ancillary services is Duquesne proposing to
2 offer to transmission customers?

3 A. Duquesne is offering the ancillary services the FERC
4 directed transmitting utilities to provide in Order
5 No. 888.

6 Q. What are those services?

7 A. Those services are:

- 8 1. Scheduling, System control and dispatch
- 9 2. Reactive Supply and voltage control from Gener-
10 ation Sources
- 11 3. Regulation and Frequency Response
- 12 4. Energy Imbalance
- 13 5. Operating Reserve-Spinning Reserve
- 14 6. Operating Reserve - Supplemental

15 Q. Please describe in more detail what Duquesne pro-
16 poses as to each ancillary service it is offering
17 including how the charge was developed, what the
18 charge is, and how the charge will be assessed
19 against each user.

20 A. I will discuss each of the six ancillary services
21 included in Order 888.

22 Q. Please discuss scheduling service.

Ex. _____ (PAW-1)
Page 3 of 22

1 A. Duquesne is not proposing to charge for system
2 control and dispatch service at this time.
3 Duquesne, however, is proposing to charge for sched-
4 uling service. Scheduling service can be provided
5 in one of two ways - manually or dynamically. To
6 the extent customers want to schedule on a dynamic
7 basis, there is likely to be set-up costs for com-
8 puter equipment and tele-communication lines, the
9 cost of which will vary by customer. As a result,
10 Duquesne proposes to charge for these costs on an as
11 incurred basis at the time a particular request is
12 received.

13 Duquesne has established a charge for schedul-
14 ing service assuming scheduling is done on a manual
15 basis. Manual scheduling requires that personnel in
16 Duquesne's system operation center be available to
17 make the necessary schedule changes and perform the
18 required accounting functions for the transmission
19 customer. Therefore, in determining the schedule
20 charge, I have divided an appropriate amount of
21 annual labor expense by the number of transactions
22 scheduled across and out of Duquesne's control area.

Ex. _____ (PAW-1)
Page 4 of 22

1 The annual labor expense was computed using data
2 from FERC account #556 and is based on an allocated
3 share of salaries associated with transmission
4 scheduling. Duquesne has estimated that amount to
5 be \$823,204. I then applied an adjustment factor of
6 1.21 to account for fringe benefits bringing the
7 total allocated labor expense to \$996,077. Dividing
8 this value by the number of hourly schedules in the
9 year (8760) yields a unit cost of \$113.71. I pro-
10 pose to charge \$100 for each schedule and change in
11 schedule submitted by a transmission customer. If
12 scheduling charges were set on a flat monthly fee
13 basis, transmission customers would have no incen-
14 tive to economize on the number of schedule changes
15 that they could effect since there would be no
16 difference in cost whether they requested 1 or 20
17 schedule changes during the day.

18 Q. Please describe reactive support from generation
19 service?

20 A. I will but first let me discuss certain aspects of
21 generation that are common for the remaining five
22 ancillary services. First, generation is associated

Ex. _____ (PAW-1)
Page 5 of 22

1 in one way or another, in varying degrees, with all
2 of these services. Putting aside scheduling and
3 dispatch (which I have already discussed), all other
4 ancillary services involve providing either energy
5 or power which ultimately come from generation
6 sources.

7 Q. Do the current FERC accounts break-out these genera-
8 tion-related costs attributable to the provision of
9 these ancillary services?

10 A. Not entirely. FERC accounting is sufficient to
11 determine total plant investment, but is not ade-
12 quate, without more, to determine specific plant
13 investment and plant related costs associated with
14 the production. For example, the FERC accounts do
15 not detail the investment and operating costs asso-
16 ciated with the production of real and reactive
17 power. In addition, investment in facilities that
18 provide scheduling capability also perform many
19 other functions relative to the day-to-day operation
20 of an electric power system.

21 Q. Is it necessary therefore to estimate what propor-
22 tion of generating equipment is used to provide for

Ex. _____ (PAW-1)
Page 6 of 22

1 the various services ancillary to the provision of
2 transmission service?

3 A. Yes. In identifying the charges for reactive and
4 voltage control, I began by identifying the equip-
5 ment components of generation plant associated with
6 the production of both real and reactive power.

7 These components include:

- 8 • unit step-up transformers,
- 9 • exciters,
- 10 • voltage regulators, and
- 11 • generators

12 The plant investment for each component was
13 obtained from Duquesne company internal plant and
14 property records. Once these individual plant
15 investment costs were collected, I then totaled them
16 for each generating unit and allocated them between
17 real and reactive components based on individual
18 unit power factor ratings.

19 Q. Before you proceed please explain what you mean by
20 real and reactive power?

21 A. What is commonly called "Power", but what engineers
22 often refer to as "real power" as an electrical

Ex. _____ (PAW-1)
Page 7 of 22

1 quantity, is defined as the product of voltage and
2 current in which the current and voltage waveforms
3 are in phase with each other. On an AC (alternating
4 current) power system the waveforms of voltage and
5 current are typically not in phase with each other,
6 and therefore only part of the product of voltage
7 and current actually is transmitted or consumed as
8 real power. Real power is ultimately converted into
9 useful work in applications such as pumping, light-
10 ing, or heating. Reactive power is the product of
11 voltage and current waveforms that are 90° out of
12 phase with each other. Reactive power establishes
13 the magnetic fields that are essential for the
14 transmission of real power, voltage transformations,
15 and electric motor function.

16 Perhaps the best way to describe the relation-
17 ship of how real and reactive power applies to
18 generation is to describe what is known in AC elec-
19 trical theory as the power triangle. The power
20 triangle is a right triangle in which the base
21 represents the real power and the vertical side
22 represents the reactive power. Consistent with the

Ex. _____ (PAW-1)
Page 8 of 22

1 mathematics of geometry, the hypotenuse is equal to
2 the square root of the sum of the squares of the
3 other two sides. By dividing all of the sides by
4 the hypotenuse, the real and reactive components of
5 the triangle can be represented on a per unit basis
6 where the sum of the squares of the two sides equal
7 unity.

8 In designing a generator, manufacturer's define
9 rated power factor as the point in which the genera-
10 tor will produce rated power most efficiently. Good
11 utility practice is to operate generators at or near
12 the manufacturer's rated power factor. The power
13 factor represents on a per unit basis how much of
14 the total output of the generator is real power.
15 Based on the right triangle relationship, the square
16 of the power factor represents the allocation of
17 real power output. It follows that $1 - (\text{pf})^2$ repre-
18 sents the appropriate allocation of reactive power,
19 and then multiplying the result by the total plant
20 investment would yield the per unit amount that
21 should be allocated to reactive cost. For example,
22 under my approach assuming 0.90 power factor for a

Ex. _____ (PAW-1)
Page 9 of 22

1 generator, I would estimate 19% or $\{[1-(.9)^2]*100\}$
2 of plant investment as devoted to production of
3 reactive power.

4 Q Why is reactive support important?

5 A. Maintaining acceptable voltage profiles across the
6 transmission network is critical to insure reliable
7 operation of the network. Transmission voltages
8 must typically be regulated to +/- 5% of the nominal
9 operating voltage. Voltage excursions outside this
10 range can damage equipment and detrimentally affect
11 the security of the interconnected transmission
12 network. Generators not only supply and absorb
13 reactive power but also regulate the injection and
14 extraction of reactive power to maintain the desired
15 voltage levels at specific points on the network.
16 In addition, generators also have reserve reactive
17 power capability that can be called upon to meet the
18 sudden outages of other generating units or trans-
19 mission lines that, if left unattended, would ad-
20 versely affect the balance of power on the network.
21 Q. Now that you have explained reactive power, please
22 explain how you estimated the associated costs, and

Ex. ____ (PAW-1)
Page 10 of 22

1 why it is important to the transmission system,
2 please tell me how you estimated the reactive power
3 charges Duquesne proposes to charge?

4 A. After I determined the total plant investment costs
5 associated with the reactive support service by
6 summing up the investment by plant (\$14.3 million),
7 I then divided this amount by the total generation
8 plant investment (\$1,087 million). This ratio
9 (.013) of reactive plant to total plant was then
10 multiplied by the annual revenue requirement (\$368
11 million) for total generation plant derived and
12 explained by Mr. Cater, in his testimony. The
13 product (\$4.8 million) yields the revenue require-
14 ment associated with the production of reactive
15 power.

16 Q. Once you estimated the total annual revenue require-
17 ment associated with the production of reactive
18 power from generation, how did you propose to charge
19 for this service?

20 A. For billing purposes the monthly charge will be
21 determined by allocating 1/12 of the annual revenue
22 requirement and applying it to the customers load

Ex. ____ (PAW-1)
Page 11 of 22

1 ratio share. Monthly peak demand will be measured
2 at the transmission customer's meter over a 15
3 minute demand interval. The allocated revenue
4 requirement will then be adjusted up or down depend-
5 ing on the transmission customer's average power
6 factor deviation around .95. The adjustment will be
7 based on dividing .95 by the customers average power
8 factor and then multiplying by the allocated revenue
9 requirement. Average monthly power factor will be
10 calculated by metering the transmission customer's
11 monthly MWh and MVARh consumption and applying the
12 formula provided in the tariff.

13 Q. How was 95% power factor chosen as the basis for
14 adjusting demand.?

15 A. Consistent with industry practice, the monthly
16 demand will be scaled either up or down by the ratio
17 of .95 to the customers power factor. This effec-
18 tively provides a credit for those customers who
19 have a power factor greater then .95 and a penalty
20 for those who have a power factor less than .95. A
21 leading power factor will be credited as a unity
22 power factor.

Ex. ____ (PAW-1)
Page 12 of 22

- 1 Q. Please define regulation and frequency control
2 service?
- 3 A. Regulation and Frequency control is, as the FERC
4 states, the service of load following (Order 888
5 slip op. at p. 212). As the FERC explains, someone
6 must supply power to meet any difference between the
7 customer's actual load and scheduled generation.
8 Duquesne proposes to levy a demand charge equivalent
9 to its own annual carrying cost of capacity applied
10 to the maximum difference between scheduled genera-
11 tion and actual load. This represents capacity
12 supplied by Duquesne as measured by the maximum
13 monthly 15-minute metered demand.
- 14 Q. Duquesne does not have to schedule any power to meet
15 those deviations in load so why should you charge
16 the transmission customer a capacity charge?
- 17 A. As the FERC states in Order 888 slip op at p. 212
18 someone must supply power to meet any difference
19 between a customer's actual and scheduled genera-
20 tion.

Ex. ____ (PAW-1)
Page 13 of 22

- 1 Q. Why shouldn't the transmission customer receive at
2 least some credit for the capacity he is paying for
3 when he pays or provides daily operating reserves?
- 4 A. The operating reserves are a function of load, they
5 are not part of load. Thus if a customer attempts
6 to use up some of the capacity committed to daily
7 operating reserve at the time of the peak, Duquesne
8 will be deficient from ECAR's point of view. To
9 avoid the deficiency, the customer must purchase
10 from Duquesne or otherwise supply capacity to cover
11 any difference between actual and scheduled genera-
12 tion in addition to the capacity needed to cover the
13 required operating reserves.
- 14 Q. Is this comparable to the treatment Duquesne's own
15 native ratepayers receive?
- 16 A. It is, indirectly. Duquesne's planning criteria
17 require it to maintain its own or purchase enough
18 capacity to meet its load following capacity re-
19 quirements and still meet ECAR operating reserve
20 capacity requirements.
- 21 Q. Please explain whether Duquesne follows NERC guide-
22 lines in setting its load following or regulating

Ex. _____ (PAW-1)
Page 14 of 22

1 margins and how these guidelines are used in deter-
2 mining the load following charges you have estimat-
3 ed?

4 A. Certainly. Duquesne complies with NERC guidelines
5 within the operational constraints of its ability to
6 do so. Current NERC policies on control area per-
7 formance are merely recommended standards at this
8 time and are under review. NERC "A1" and "A2"
9 standards are currently, recommendations that each
10 control area maintain 90% compliance. NERC is
11 currently reviewing whether these recommendations
12 should be changed to requirements.

13 Q. Please explain what is meant by the terms "A1" and
14 "A2"?

15 A. "A1" refers to the Area Control Error (ACE) and
16 means that the control area return to zero every 10
17 minutes. "A2" dictates how far a control area's ACE
18 can vary from zero. Duquesne has not explicitly
19 incorporated the NERC guidelines into its charge for
20 regulation and frequency control.

21 Q. Then how are you proposing to charge for this ser-
22 vice?

Ex. ____ (PAW-1)
Page 15 of 22

1 A. I am proposing to charge for this service on the
2 basis of the deviation between the transmission
3 customers load and schedule. If a customer's load
4 exceeds his schedule, Duquesne will then be required
5 to use its own fossil and combustion turbine gener-
6 ating sources to supplement the customers schedule
7 in order to meet load. The capacity related charge
8 for this service will be computed by dividing the
9 annual revenue requirements for Duquesne's fossil
10 and combustion turbine units (\$131,672,164) by 12 to
11 get a monthly revenue requirement. This value will
12 then be allocated on a load ratio share basis using
13 the monthly maximum deviation expressed as a per-
14 centage of total load. Mr. Cater provides the
15 support in his testimony for the development of
16 annual revenue requirements.

17 In addition, I am proposing to assess a small
18 energy charge, estimated to be \$.007/Mwh. This
19 charge represents the expected annual unitized
20 energy costs for Duquesne in following load and
21 meeting daily peak demands on its system for 1996.
22 This cost was determined by running two production

Ex. _____ (PAW-1)
Page 16 of 22

1 cost simulations. I instructed that a base produc-
2 tion cost simulation be run based on expected load
3 and plant availability conditions for 1996. This
4 run modeled the regulation requirements recognizing
5 such things as minimum unit output and down times.
6 Next I had another run prepared which ignored the
7 regulation requirements. This run produced slightly
8 lower production costs because of greater flexibili-
9 ty in following the daily load variations. The
10 difference in annual production costs (\$90,000) was
11 then divided by the total projected MWh of energy
12 deliveries (13,167.2 GWH) on the Duquesne system to
13 produce a unitized value of energy cost associated
14 with regulation.

15 Q. Please turn to energy imbalance service.

16 A. Energy imbalance refers to the accumulated error
17 that results from the inability of the control area
18 operator to perfectly follow instantaneous fluctua-
19 tions in metered load. Stated another way, energy
20 imbalance represents the difference between energy
21 measured at the meter and the integration of sched-
22 uled power over time. When metered consumption is

Ex. _____ (PAW-1)
Page 17 of 22

1 greater than total scheduled energy, the local
2 control area operator must provide the difference.
3 Conversely, when measured consumption is less than
4 total scheduled energy, the local control area
5 operator must back off its own generating units,
6 which may be less costly to run than the generation
7 of the transmission customer.

8 Q. What is the cost to Duquesne of addressing energy
9 imbalance?

10 A. The cost to Duquesne is the out-of-pocket cost for
11 energy supplied or the opportunity cost.

12 Q. How does Duquesne propose to charge transmission
13 customers for this service?

14 A. Ideally Duquesne would prefer there is no imbalance.
15 Notwithstanding the instantaneous variations in a
16 customer's load, the problem is further aggravated
17 in that Duquesne can only schedule power into or out
18 of its system in 1 MW increments. Duquesne proposes
19 to accept variations in energy up to 1.5% of the
20 on-peak and off-peak energy scheduled. For energy
21 supplied by Duquesne in this band Duquesne will
22 charge based on the average system lambda λ . For

Ex. ____ (PAW-1)
Page 18 of 22

1 energy taken by Duquesne, the transmission customer
2 will receive a credit of 90% of the average system
3 lambda. For variations outside of the band,
4 Duquesne proposes to charge \$100/MWH for energy
5 supplied and provide a credit of 70% of the average
6 system lambda.

7 Q. Please describe operating reserve service.

8 A. Operating reserves is the amount of generation in
9 excess of load that is either on-line (spinning) or
10 can be accessed within 10 minutes (supplemental) to
11 primarily supply power in the event of a sudden
12 outage at a large generating unit anywhere within
13 the ECAR region. Other factors considered in the
14 determination of the amount of daily operating
15 reserves are regulation requirements and load fore-
16 cast error. Spinning reserves represent the total
17 amount of generating capacity on-line that is in
18 excess of system load but less than the maximum
19 generating plant output. Supplemental or non-spin-
20 ning reserves are the amount of generating capacity
21 that can be brought on-line within 10 minutes. Non-

Ex. _____ (PAW-1)
Page 19 of 22

1 spinning reserves can be capacity such as combustion
2 turbines, and, in some cases, interruptible load.

3 Q. What requirements does Duquesne maintain?

4 A. As a member of ECAR, Duquesne is required to demon-
5 strate on a daily basis that it has sufficient oper-
6 ating reserves available in excess of predicted load
7 for the day. One component of this requirement is
8 the spinning reserve which provides for load regula-
9 tion and system frequency fluctuations. The other
10 component is supplemental or non-spinning reserves
11 which provides for protection against an unexpected
12 loss of generation. Duquesne's total operating
13 reserve requirement is 6.6 %, of which at least 3%
14 has to be in the form of spinning with the balance
15 in the form of non-spinning reserves.

16 Q. Does Duquesne differentiate between spinning and
17 non-spinning reserves?

18 A. Yes. Duquesne, however, typically satisfies its
19 entire daily ECAR operating reserve requirement by
20 carrying sufficient generation on its system in the
21 form of spinning. While Duquesne has approximately
22 88 Mws of interruptible load under contract with

Ex. ____ (PAW-1)
Page 20 of 22

1 retail customers, it cannot be used in satisfaction
2 of our supplemental operating reserve requirements.
3 As a result, Duquesne can only credit its combustion
4 turbine capacity for purposes of its non-spinning
5 reserve requirement.

6 Q. In light of these requirements, please explain how
7 they were used in determining your proposed charge
8 for operating reserves?

9 A. I have developed the charge in two parts - a capaci-
10 ty component and an energy component. In developing
11 the capacity component I used the plant investment
12 costs of Duquesne's fossil units. I used the coal
13 plants because these are the plants Duquesne uses to
14 meet its spinning reserve requirements. Duquesne's
15 nuclear units are strictly base-loaded units that
16 are not used to meet this requirement and therefore
17 should not be included in setting the charge for
18 spinning reserves. The combined revenue require-
19 ments for the coal fired and combustion turbine
20 plants was provided to me by Mr. Cater and deter-
21 mined to be \$131,672,164. I then subtracted the
22 annual revenue requirement for the combustion tur-

Ex. _____ (PAW-1)
Page 21 of 22

1 bine plant of \$2,380,505 to arrive at a value of
2 \$129,291,659 for the fossil plants.

3 The capacity related charge for spinning re-
4 serves will be completed by dividing the annual
5 revenue requirement for Duquesne's fossil units
6 (\$129,291,659) by 12 to get a monthly revenue re-
7 quirement. This value was then multiplied times 3%
8 to determine the revenue requirements associated
9 with spinning. Customers will then be billed on the
10 basis of their load ratio shares.

11 Q. Explain your proposal for charging transmission
12 customers for supplemental or non-spinning reserves.

13 A. I am proposing to charge in a similar fashion. In
14 setting the charge for non-spinning reserves, howev-
15 er, I have used our required 3.6% non-spinning re-
16 serve ratio, the revenue requirements for Duquesne's
17 Brunot Island combustion turbine (\$2,380,505).
18 Customers will also be billed on the basis of load
19 ratio shares. Again, Mr. Cater provided me with the
20 necessary revenue requirement information for the
21 combustion turbine plant.

Ex. ____ (PAW-1)
Page 22 of 22

1 There is also an energy component that repre-
2 sents the energy cost for no-load heat to maintain
3 Duquesne's spinning reserves. On a monthly basis
4 Duquesne will determine its total energy cost asso-
5 ciated with providing spinning reserves. Duquesne
6 will bill customers who purchase spinning reserves
7 on the basis of their load ratio shares.

8 Q. Does this conclude your testimony?

9 A. Yes.

ALLOCATED COST/REVENUE COMPARISON

1996 Cost/Revenue	PAPUC	RESIDENTIAL	GEN. SERVICE	LIGHTING
Rate Base	\$2,367,154,351	\$830,087,949	\$1,496,859,986	\$40,206,416
ROR @ 9.61%	9.61%	9.61%	9.61%	9.61%
Return	\$227,483,533	\$79,771,452	\$143,848,245	\$3,863,837
Expense	\$907,098,040	\$320,995,551	\$572,714,771	\$13,387,718
Allocated Cost of Service	\$1,134,581,573	\$400,767,003	\$716,563,016	\$17,251,555
Actual 1996 Revenues	\$1,085,649,638	\$404,017,095	\$664,497,624	\$17,134,919
Cost less Revenue	\$48,931,935	(\$3,250,092)	\$52,065,392	\$116,636

1996 Cost/Revenue (adjusted)	PAPUC	RESIDENTIAL	GEN. SERVICE	LIGHTING
Rate Base	\$2,367,154,351	\$830,087,949	\$1,496,859,986	\$40,206,416
Class Adjusted ROR	9.61%	10.69%	8.95%	11.87%
Return	\$227,483,533	\$88,773,022	\$133,938,210	\$4,772,301
Expense	\$907,098,040	\$320,995,551	\$572,714,771	\$13,387,718
Adjusted Cost of Service	\$1,134,581,573	\$409,768,573	\$706,652,981	\$18,160,019
Adjusted 1996 Revenues	\$1,104,215,125	\$408,990,686	\$677,980,833	\$17,243,606
Cost less Revenue (adjusted)	\$30,366,448	\$777,887	\$28,672,148	\$916,413

ALLOCATED COST/REVENUE COMPARISON

1996 COST/REVENUE	PA PUC	RA	RS	RH	GS/OM	GMII	GL	GLH	L	HVPS	AL	SE	SM	SH	TRAFFIC SIGNALS
Rate Base	\$2,367,154,351	\$8,291,477	\$741,796,375	\$80,000,097	\$602,175,296	\$70,313,771	\$426,787,789	\$71,921,874	\$195,420,848	\$130,240,408	\$3,123	\$13,198,087	\$25,192,269	\$292,136	\$1,520,801
ROR @ 9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%	9.61%
RETURN	\$227,483,533	\$796,811	\$71,286,632	\$7,688,009	\$57,869,048	\$6,737,153	\$41,014,307	\$6,911,892	\$18,779,943	\$12,516,103	\$300	\$1,268,336	\$2,420,977	\$28,074	\$146,149
EXPENSE	\$907,098,040	\$3,093,186	\$288,739,258	\$29,163,107	\$214,260,345	\$25,098,152	\$166,408,039	\$27,756,054	\$77,618,135	\$61,573,846	\$1,164	\$4,397,912	\$8,159,716	\$94,834	\$734,092
Allocated Cost of Service	\$1,134,581,573	\$3,889,997	\$360,025,890	\$36,831,116	\$272,129,391	\$31,835,305	\$207,472,346	\$34,661,748	\$96,398,078	\$74,089,949	\$1,463	\$5,666,248	\$10,380,693	\$122,908	\$880,241
Actual Revenues	\$1,085,849,638	\$3,349,885	\$374,878,804	\$25,788,406	\$174,559,065	\$27,070,932	\$201,808,495	\$29,104,629	\$82,353,498	\$49,601,005	\$1,323	\$3,093,842	\$12,258,677	\$165,787	\$1,615,290
Cost less Revenue	\$48,931,935	\$540,112	(\$14,851,914)	\$11,062,710	(\$2,429,474)	\$4,784,373	\$5,613,851	\$5,563,117	\$14,044,580	\$24,488,944	\$141	\$2,372,406	(\$1,677,984)	(\$42,879)	(\$735,049)
Adjusted COST/REVENUE	PA PUC	RA	RS	RH	GS/OM	GMII	GL	GLH	L	HVPS	AL	SE	SM	SH	AFFIC LIGHT
Rate Base	\$2,367,154,351	\$8,291,477	\$741,796,375	\$80,000,097	\$602,175,296	\$70,313,771	\$426,787,789	\$71,921,874	\$195,420,848	\$130,240,408	\$3,123	\$13,198,087	\$25,192,269	\$292,136	\$1,520,801
ROR @ 9.61%	9.61%	10.46%	10.64%	10.46%	10.09%	10.88%	8.88%	8.73%	6.62%	6.62%	11.79%	3.91%	16.75%	11.58%	24.52%
RETURN	\$227,483,533	\$867,087	\$78,925,017	\$8,366,061	\$60,779,142	\$7,646,930	\$37,909,429	\$6,280,574	\$12,940,173	\$8,624,123	\$368	\$518,988	\$4,218,973	\$33,837	\$372,829
EXPENSE	\$907,098,040	\$3,093,186	\$288,739,258	\$29,163,107	\$214,260,345	\$25,098,152	\$166,408,039	\$27,756,054	\$77,618,135	\$61,573,846	\$1,164	\$4,397,912	\$8,159,716	\$94,834	\$734,092
Allocated Cost of Service	\$1,134,581,573	\$3,960,273	\$367,664,275	\$37,529,168	\$275,039,687	\$32,745,082	\$204,317,468	\$34,036,628	\$90,558,308	\$70,197,969	\$1,532	\$4,916,900	\$12,378,691	\$128,671	\$1,106,921
Adjusted 1996 Revenues	\$1,101,215,125	\$3,400,589	\$379,338,751	\$26,251,345	\$278,720,764	\$27,562,659	\$205,894,834	\$29,786,549	\$84,614,690	\$51,401,337	\$1,342	\$3,136,712	\$12,305,786	\$167,041	\$1,652,725
Cost less Revenue	\$30,366,448	\$559,683	(\$11,674,477)	\$11,277,823	(\$3,681,077)	\$5,182,423	(\$1,577,365)	\$4,250,079	\$5,943,618	\$18,796,632	\$190	\$1,780,189	\$71,905	(\$38,370)	(\$525,805)

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE RSD - RESIDENTIAL SERVICE DELIVERY

ENERGY USAGE - KWH		0	100	200	300	400	500	750	1000	1500	2000	2500	3000	3500	4000	4500	5000	
RATE RS (bundled rate)																		
Customer Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Energy Charge per kWh	\$ 0.1166 per kWh	\$ -	\$ 11.66	\$ 23.32	\$ 34.98	\$ 46.64	\$ 58.30	\$ 87.45	\$ 116.60	\$ 174.90	\$ 233.20	\$ 291.50	\$ 349.80	\$ 408.10	\$ 466.40	\$ 524.70	\$ 583.00	
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38	
Supplier Market Price	1.856 cents per kWh																	
D.L.C. Customer Gen. Charge/Credit	1.856 cents per kWh																	
FIXED CTC CALCULATION																		
Monthly RS Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38	
Less:																		
Customer Distribution Charge	\$ 6.38 per month	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	
Transmission Charge	\$ 0.0045 per kWh	\$ -	\$ (0.45)	\$ (0.90)	\$ (1.35)	\$ (1.80)	\$ (2.25)	\$ (3.38)	\$ (4.51)	\$ (6.76)	\$ (9.02)	\$ (11.27)	\$ (13.53)	\$ (15.78)	\$ (18.03)	\$ (20.29)	\$ (22.54)	
Distribution Charge	\$ 0.0281 per kWh	\$ -	\$ (2.81)	\$ (5.61)	\$ (8.42)	\$ (11.23)	\$ (14.03)	\$ (21.05)	\$ (28.07)	\$ (42.10)	\$ (56.14)	\$ (70.17)	\$ (84.20)	\$ (98.24)	\$ (112.27)	\$ (126.30)	\$ (140.34)	
Variable CTC	\$ 0.0072 per kWh	\$ -	\$ (0.72)	\$ (1.43)	\$ (2.15)	\$ (2.87)	\$ (3.58)	\$ (5.37)	\$ (7.16)	\$ (10.75)	\$ (14.33)	\$ (17.91)	\$ (21.49)	\$ (25.07)	\$ (28.65)	\$ (32.24)	\$ (35.82)	
D.L.C. Customer Gen. Charge/Credit	\$ 0.01856 per kWh	\$ -	\$ (1.86)	\$ (3.71)	\$ (5.57)	\$ (7.42)	\$ (9.28)	\$ (13.92)	\$ (18.56)	\$ (27.84)	\$ (37.12)	\$ (46.40)	\$ (55.68)	\$ (64.96)	\$ (74.24)	\$ (83.52)	\$ (92.80)	
Fixed CTC		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 43.73	\$ 58.30	\$ 87.45	\$ 116.60	\$ 145.75	\$ 174.90	\$ 204.05	\$ 233.20	\$ 262.35	\$ 291.50	
RATE RSD (proposed unbundled rate)																		
Fixed Charges																		
Customer Distribution Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	
Fixed CTC (per month)		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 43.73	\$ 58.30	\$ 87.45	\$ 116.60	\$ 145.75	\$ 174.90	\$ 204.05	\$ 233.20	\$ 262.35	\$ 291.50	
Energy Charges																		
Transmission Charge	\$ 0.0045 per kWh	\$ -	\$ 0.45	\$ 0.90	\$ 1.35	\$ 1.80	\$ 2.25	\$ 3.38	\$ 4.51	\$ 6.76	\$ 9.02	\$ 11.27	\$ 13.53	\$ 15.78	\$ 18.03	\$ 20.29	\$ 22.54	
Distribution Charge	\$ 0.0281 per kWh	\$ -	\$ 2.81	\$ 5.61	\$ 8.42	\$ 11.23	\$ 14.03	\$ 21.05	\$ 28.07	\$ 42.10	\$ 56.14	\$ 70.17	\$ 84.20	\$ 98.24	\$ 112.27	\$ 126.30	\$ 140.34	
Variable CTC	\$ 0.0072 per kWh	\$ -	\$ 0.72	\$ 1.43	\$ 2.15	\$ 2.87	\$ 3.58	\$ 5.37	\$ 7.16	\$ 10.75	\$ 14.33	\$ 17.91	\$ 21.49	\$ 25.07	\$ 28.65	\$ 32.24	\$ 35.82	
Supplier Market Price	\$ 0.01856 per kWh	\$ -	\$ 1.86	\$ 3.71	\$ 5.57	\$ 7.42	\$ 9.28	\$ 13.92	\$ 18.56	\$ 27.84	\$ 37.12	\$ 46.40	\$ 55.68	\$ 64.96	\$ 74.24	\$ 83.52	\$ 92.80	
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38	
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE RHD - RESIDENTIAL SERVICE HEATING DELIVERY - WINTER

ENERGY USAGE - KWH		0	100	200	300	400	500	750	1000	1500	2000	2500	3000	3500	4000	4500	5000	
RATE RH (bundled rate)																		
Customer Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Energy Charges																		
First Block (up to 500 kWh)	\$ 0.1166 per kWh	\$ -	\$ 11.66	\$ 23.32	\$ 34.98	\$ 46.64	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30
Excess kWh	\$ 0.0449 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 11.23	\$ 22.45	\$ 44.90	\$ 67.35	\$ 89.80	\$ 112.25	\$ 134.70	\$ 157.15	\$ 179.60	\$ 202.05	
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 75.91	\$ 87.13	\$ 109.58	\$ 132.03	\$ 154.48	\$ 176.93	\$ 199.38	\$ 221.83	\$ 244.28	\$ 266.73	
Supplier Market Price	1.844 cents per kWh																	
DLC Customer Gen. Charge/Credit	1.844 cents per kWh																	
FIXED CTC CALCULATION																		
Monthly RH Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 75.91	\$ 87.13	\$ 109.58	\$ 132.03	\$ 154.48	\$ 176.93	\$ 199.38	\$ 221.83	\$ 244.28	\$ 266.73	
Less:																		
Customer Distribution Charge	\$ 6.38 per month	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	
Transmission Charges																		
First 500 kWh	\$ 0.0052 per kWh	\$ -	\$ (0.52)	\$ (1.05)	\$ (1.57)	\$ (2.10)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	
Excess kWh	\$ 0.0035 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.87)	\$ (1.74)	\$ (3.48)	\$ (5.22)	\$ (6.97)	\$ (8.71)	\$ (10.45)	\$ (12.19)	\$ (13.93)	\$ (15.67)	
Distribution Charges																		
First 500 kWh	\$ 0.0316 per kWh	\$ -	\$ (3.16)	\$ (6.32)	\$ (9.48)	\$ (12.64)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	
Excess kWh	\$ 0.0210 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (5.25)	\$ (10.49)	\$ (20.98)	\$ (31.47)	\$ (41.96)	\$ (52.45)	\$ (62.94)	\$ (73.43)	\$ (83.92)	\$ (94.41)	
Variable CTC Charges																		
First 500 kWh	\$ 0.0030 per kWh	\$ -	\$ (0.30)	\$ (0.60)	\$ (0.90)	\$ (1.20)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	
Excess kWh	\$ 0.0020 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.50)	\$ (1.00)	\$ (2.00)	\$ (3.00)	\$ (3.99)	\$ (4.99)	\$ (5.99)	\$ (6.99)	\$ (7.99)	\$ (8.99)	
DLC Customer Gen. Charge/Credit	\$ 0.01844 per kWh	\$ -	\$ (1.84)	\$ (3.69)	\$ (5.53)	\$ (7.38)	\$ (9.22)	\$ (13.83)	\$ (18.44)	\$ (27.66)	\$ (36.88)	\$ (46.10)	\$ (55.32)	\$ (64.54)	\$ (73.76)	\$ (82.98)	\$ (92.20)	
Fixed CTC		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	
RATE RHD (proposed unbundled rate)																		
Fixed Charges																		
Customer Distribution Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	
Fixed CTC (per month)		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	
Delivery Charges-Energy																		
Transmission Charges																		
First 500 kWh	\$ 0.0052 per kWh	\$ -	\$ 0.52	\$ 1.05	\$ 1.57	\$ 2.10	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	
Excess kWh	\$ 0.0035 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.87	\$ 1.74	\$ 3.48	\$ 5.22	\$ 6.97	\$ 8.71	\$ 10.45	\$ 12.19	\$ 13.93	\$ 15.67	
Distribution Charges																		
First 500 kWh	\$ 0.0316 per kWh	\$ -	\$ 3.16	\$ 6.32	\$ 9.48	\$ 12.64	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	
Excess kWh	\$ 0.0210 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5.25	\$ 10.49	\$ 20.98	\$ 31.47	\$ 41.96	\$ 52.45	\$ 62.94	\$ 73.43	\$ 83.92	\$ 94.41	
Variable CTC Charges																		
First 500 kWh	\$ 0.0030 per kWh	\$ -	\$ 0.30	\$ 0.60	\$ 0.90	\$ 1.20	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	
Excess kWh	\$ 0.0020 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.50	\$ 1.00	\$ 2.00	\$ 3.00	\$ 3.99	\$ 4.99	\$ 5.99	\$ 6.99	\$ 7.99	\$ 8.99	
Supplier Market Price	\$ 0.01844 per kWh	\$ -	\$ 1.84	\$ 3.69	\$ 5.53	\$ 7.38	\$ 9.22	\$ 13.83	\$ 18.44	\$ 27.66	\$ 36.88	\$ 46.10	\$ 55.32	\$ 64.54	\$ 73.76	\$ 82.98	\$ 92.20	
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 75.91	\$ 87.13	\$ 109.58	\$ 132.03	\$ 154.48	\$ 176.93	\$ 199.38	\$ 221.83	\$ 244.28	\$ 266.73	
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE RHD - RESIDENTIAL SERVICE HEATING DELIVERY - SUMMER

ENERGY USAGE - KWH		0	100	200	300	400	500	750	1000	1500	2000	2500	3000	3500	4000	4500	5000
RATE RH (bundled rate)																	
Customer Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Energy Charges																	
First Block (up to 500 kWh)	\$ 0.1166 per kWh	\$ -	\$ 11.66	\$ 23.32	\$ 34.98	\$ 46.64	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30
Excess kWh	\$ 0.1166 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 29.15	\$ 58.30	\$ 116.60	\$ 174.90	\$ 233.20	\$ 291.50	\$ 349.80	\$ 408.10	\$ 466.40	\$ 524.70
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38

Supplier Market Price 1,844 cents per kWh
DLC Customer Gen Charge/Credit 1,844 cents per kWh

FIXED CTC CALCULATION

Monthly RH Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38
Less:																	
Customer Distribution Charge	\$ 6.38 per month	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)
Transmission Charges																	
First 500 kWh	\$ 0.0052 per kWh	\$ -	\$ (0.52)	\$ (1.05)	\$ (1.57)	\$ (2.10)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)	\$ (2.62)
Excess kWh	\$ 0.0052 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1.31)	\$ (2.62)	\$ (5.25)	\$ (7.87)	\$ (10.49)	\$ (13.12)	\$ (15.74)	\$ (18.36)	\$ (20.99)	\$ (23.61)
Distribution Charges																	
First 500 kWh	\$ 0.0316 per kWh	\$ -	\$ (3.16)	\$ (6.32)	\$ (9.48)	\$ (12.64)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)	\$ (15.80)
Excess kWh	\$ 0.0316 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (7.90)	\$ (15.80)	\$ (31.60)	\$ (47.41)	\$ (63.21)	\$ (79.01)	\$ (94.81)	\$ (110.62)	\$ (126.42)	\$ (142.22)
Variable CTC Charges																	
First 500 kWh	\$ 0.0030 per kWh	\$ -	\$ (0.30)	\$ (0.60)	\$ (0.90)	\$ (1.20)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)	\$ (1.50)
Excess kWh	\$ 0.0030 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.75)	\$ (1.50)	\$ (3.01)	\$ (4.51)	\$ (6.02)	\$ (7.52)	\$ (9.03)	\$ (10.53)	\$ (12.03)	\$ (13.54)
DLC Customer Gen Charge/Credit	\$ 0.01844 per kWh	\$ -	\$ (1.84)	\$ (3.69)	\$ (5.53)	\$ (7.38)	\$ (9.22)	\$ (13.83)	\$ (18.44)	\$ (27.66)	\$ (36.88)	\$ (46.10)	\$ (55.32)	\$ (64.54)	\$ (73.76)	\$ (82.98)	\$ (92.20)
Fixed CTC		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 43.73	\$ 58.30	\$ 87.45	\$ 116.60	\$ 145.75	\$ 174.90	\$ 204.05	\$ 233.20	\$ 262.35	\$ 291.50

RATE RHD (proposed unbundled rate)

Fixed Charges																	
Customer Distribution Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Fixed CTC (per month)		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 43.73	\$ 58.30	\$ 87.45	\$ 116.60	\$ 145.75	\$ 174.90	\$ 204.05	\$ 233.20	\$ 262.35	\$ 291.50
Delivery Charges - Energy																	
Transmission Charges																	
First 500 kWh	\$ 0.0052 per kWh	\$ -	\$ 0.52	\$ 1.05	\$ 1.57	\$ 2.10	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62	\$ 2.62
Excess kWh	\$ 0.0052 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1.31	\$ 2.62	\$ 5.25	\$ 7.87	\$ 10.49	\$ 13.12	\$ 15.74	\$ 18.36	\$ 20.99	\$ 23.61
Distribution Charges																	
First 500 kWh	\$ 0.0316 per kWh	\$ -	\$ 3.16	\$ 6.32	\$ 9.48	\$ 12.64	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80	\$ 15.80
Excess kWh	\$ 0.0316 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 7.90	\$ 15.80	\$ 31.60	\$ 47.41	\$ 63.21	\$ 79.01	\$ 94.81	\$ 110.62	\$ 126.42	\$ 142.22
Variable CTC Charges																	
First 500 kWh	\$ 0.0030 per kWh	\$ -	\$ 0.30	\$ 0.60	\$ 0.90	\$ 1.20	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50	\$ 1.50
Excess kWh	\$ 0.0030 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.75	\$ 1.50	\$ 3.01	\$ 4.51	\$ 6.02	\$ 7.52	\$ 9.03	\$ 10.53	\$ 12.03	\$ 13.54
Supplier Market Price	\$ 0.01844 per kWh	\$ -	\$ 1.84	\$ 3.69	\$ 5.53	\$ 7.38	\$ 9.22	\$ 13.83	\$ 18.44	\$ 27.66	\$ 36.88	\$ 46.10	\$ 55.32	\$ 64.54	\$ 73.76	\$ 82.98	\$ 92.20
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE RAD - RESIDENTIAL SERVICE ADD-ON HEAT PUMP DELIVERY - WINTER

ENERGY USAGE - KWH		0	100	200	300	400	500	750	1000	1500	2000	2500	3000	3500	4000	4500	5000
RATE RA (bundled rate)																	
Customer Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Energy Charges																	
First Block (up to 500 kWh)	\$ 0.1166 per kWh	\$ -	\$ 11.66	\$ 23.32	\$ 34.98	\$ 46.64	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30
Excess kWh	\$ 0.0449 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 11.23	\$ 22.45	\$ 44.90	\$ 67.35	\$ 89.80	\$ 112.25	\$ 134.70	\$ 157.15	\$ 179.60	\$ 202.05
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 75.91	\$ 87.13	\$ 109.58	\$ 132.03	\$ 154.48	\$ 176.93	\$ 199.38	\$ 221.83	\$ 244.28	\$ 266.73

Supplier Market Price 1.848 cents per kWh
DLC Customer Gen. Charge/Credit 1.848 cents per kWh

FIXED CTC CALCULATION

Monthly RA Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 75.91	\$ 87.13	\$ 109.58	\$ 132.03	\$ 154.48	\$ 176.93	\$ 199.38	\$ 221.83	\$ 244.28	\$ 266.73
Less:																	
<u>Customer Distribution Charge</u>	\$ 6.38 per month	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)
<u>Transmission Charges</u>																	
First 500 kWh	\$ 0.0051 per kWh	\$ -	\$ (0.51)	\$ (1.03)	\$ (1.54)	\$ (2.05)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)
Excess kWh	\$ 0.0034 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.85)	\$ (1.70)	\$ (3.40)	\$ (5.10)	\$ (6.80)	\$ (8.50)	\$ (10.20)	\$ (11.90)	\$ (13.60)	\$ (15.30)
<u>Distribution Charges</u>																	
First 500 kWh	\$ 0.0279 per kWh	\$ -	\$ (2.79)	\$ (5.57)	\$ (8.36)	\$ (11.15)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)
Excess kWh	\$ 0.0185 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (4.62)	\$ (9.25)	\$ (18.49)	\$ (27.74)	\$ (36.98)	\$ (46.23)	\$ (55.47)	\$ (64.72)	\$ (73.96)	\$ (83.21)
<u>Variable CTC Charges</u>																	
First 500 kWh	\$ 0.0068 per kWh	\$ -	\$ (0.68)	\$ (1.37)	\$ (2.05)	\$ (2.73)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)
Excess kWh	\$ 0.0045 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1.13)	\$ (2.26)	\$ (4.53)	\$ (6.79)	\$ (9.06)	\$ (11.32)	\$ (13.59)	\$ (15.85)	\$ (18.11)	\$ (20.38)
DLC Customer Gen. Charge/Credit	\$ 0.01848 per kWh	\$ -	\$ (1.85)	\$ (3.70)	\$ (5.54)	\$ (7.39)	\$ (9.24)	\$ (13.86)	\$ (18.48)	\$ (27.72)	\$ (36.96)	\$ (46.20)	\$ (55.44)	\$ (64.68)	\$ (73.92)	\$ (83.16)	\$ (92.40)
Fixed CTC		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15

RATE RAD (proposed unbundled rate)

Fixed Charges			0	100	200	300	400	500	750	1000	1500	2000	2500	3000	3500	4000	4500	5000
Customer Distribution Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Fixed CTC		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15	\$ 29.15
Delivery Charges-Energy																		
<u>Transmission Charges</u>																		
First 500 kWh	\$ 0.0051 per kWh	\$ -	\$ 0.51	\$ 1.03	\$ 1.54	\$ 2.05	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56
Excess kWh	\$ 0.0034 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.85	\$ 1.70	\$ 3.40	\$ 5.10	\$ 6.80	\$ 8.50	\$ 10.20	\$ 11.90	\$ 13.60	\$ 15.30	
<u>Distribution Charges</u>																		
First 500 kWh	\$ 0.0279 per kWh	\$ -	\$ 2.79	\$ 5.57	\$ 8.36	\$ 11.15	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93
Excess kWh	\$ 0.0185 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 4.62	\$ 9.25	\$ 18.49	\$ 27.74	\$ 36.98	\$ 46.23	\$ 55.47	\$ 64.72	\$ 73.96	\$ 83.21	
<u>Variable CTC Charges</u>																		
First 500 kWh	\$ 0.0068 per kWh	\$ -	\$ 0.68	\$ 1.37	\$ 2.05	\$ 2.73	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41
Excess kWh	\$ 0.0045 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1.13	\$ 2.26	\$ 4.53	\$ 6.79	\$ 9.06	\$ 11.32	\$ 13.59	\$ 15.85	\$ 18.11	\$ 20.38	
Supplier Market Price	\$ 0.01848 per kWh	\$ -	\$ 1.85	\$ 3.70	\$ 5.54	\$ 7.39	\$ 9.24	\$ 13.86	\$ 18.48	\$ 27.72	\$ 36.96	\$ 46.20	\$ 55.44	\$ 64.68	\$ 73.92	\$ 83.16	\$ 92.40	
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 75.91	\$ 87.13	\$ 109.58	\$ 132.03	\$ 154.48	\$ 176.93	\$ 199.38	\$ 221.83	\$ 244.28	\$ 266.73	
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

**DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE RAD - RESIDENTIAL SERVICE ADD-ON HEAT PUMP DELIVERY - SUMMER**

ENERGY USAGE - KWH		0	100	200	300	400	500	750	1000	1500	2000	2500	3000	3500	4000	4500	5000
RATE RA (bundled rate)																	
Customer Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Energy Charges																	
First Block (up to 500 kWh)	\$ 0.1166 per kWh	\$ -	\$ 11.66	\$ 23.32	\$ 34.98	\$ 46.64	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30	\$ 58.30
Excess kWh	\$ 0.1166 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 29.15	\$ 58.30	\$ 116.60	\$ 174.90	\$ 233.20	\$ 291.50	\$ 349.80	\$ 408.10	\$ 466.40	\$ 524.70
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38

Supplier Market Price 1.848 cents per kWh
DLC Customer Gen Charge/Credit 1.848 cents per kWh

FIXED CTC CALCULATION

Monthly RA Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38
Less:																	
Customer Distribution Charge	\$ 6.38 per month	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)	\$ (6.38)
Transmission Charges																	
First 500 kWh	\$ 0.0051 per kWh	\$ -	\$ (0.51)	\$ (1.03)	\$ (1.54)	\$ (2.05)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)	\$ (2.56)
Excess kWh	\$ 0.0051 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1.28)	\$ (2.56)	\$ (5.13)	\$ (7.69)	\$ (10.25)	\$ (12.81)	\$ (15.38)	\$ (17.94)	\$ (20.50)	\$ (23.07)
Distribution Charges																	
First 500 kWh	\$ 0.0279 per kWh	\$ -	\$ (2.79)	\$ (5.57)	\$ (8.36)	\$ (11.15)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)	\$ (13.93)
Excess kWh	\$ 0.0279 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (6.97)	\$ (13.93)	\$ (27.87)	\$ (41.80)	\$ (55.74)	\$ (69.67)	\$ (83.61)	\$ (97.54)	\$ (111.48)	\$ (125.41)
Variable CTC Charges																	
First 500 kWh	\$ 0.0068 per kWh	\$ -	\$ (0.68)	\$ (1.37)	\$ (2.05)	\$ (2.73)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)	\$ (3.41)
Excess kWh	\$ 0.0068 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1.71)	\$ (3.41)	\$ (6.83)	\$ (10.24)	\$ (13.65)	\$ (17.06)	\$ (20.48)	\$ (23.89)	\$ (27.30)	\$ (30.71)
DLC Customer Gen Charge/Credit	\$ 0.01848 per kWh	\$ -	\$ (1.85)	\$ (3.70)	\$ (5.54)	\$ (7.39)	\$ (9.24)	\$ (13.86)	\$ (18.48)	\$ (27.72)	\$ (36.96)	\$ (46.20)	\$ (55.44)	\$ (64.68)	\$ (73.92)	\$ (83.16)	\$ (92.40)
Fixed CTC		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 43.73	\$ 58.30	\$ 87.45	\$ 116.60	\$ 145.75	\$ 174.90	\$ 204.05	\$ 233.20	\$ 262.35	\$ 291.50

RATE RAD (proposed unbundled rate)

Fixed Charges																	
Customer Distribution Charge	\$ 6.38 per month	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38	\$ 6.38
Fixed CTC (per month)		\$ -	\$ 5.83	\$ 11.66	\$ 17.49	\$ 23.32	\$ 29.15	\$ 43.73	\$ 58.30	\$ 87.45	\$ 116.60	\$ 145.75	\$ 174.90	\$ 204.05	\$ 233.20	\$ 262.35	\$ 291.50
Delivery Charges-Energy																	
Transmission Charges																	
First 500 kWh	\$ 0.0051 per kWh	\$ -	\$ 0.51	\$ 1.03	\$ 1.54	\$ 2.05	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56	\$ 2.56
Excess kWh	\$ 0.0051 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1.28	\$ 2.56	\$ 5.13	\$ 7.69	\$ 10.25	\$ 12.81	\$ 15.38	\$ 17.94	\$ 20.50	\$ 23.07
Distribution Charges																	
First 500 kWh	\$ 0.0279 per kWh	\$ -	\$ 2.79	\$ 5.57	\$ 8.36	\$ 11.15	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93	\$ 13.93
Excess kWh	\$ 0.0279 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6.97	\$ 13.93	\$ 27.87	\$ 41.80	\$ 55.74	\$ 69.67	\$ 83.61	\$ 97.54	\$ 111.48	\$ 125.41
Variable CTC Charges																	
First 500 kWh	\$ 0.0068 per kWh	\$ -	\$ 0.68	\$ 1.37	\$ 2.05	\$ 2.73	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41	\$ 3.41
Excess kWh	\$ 0.0068 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1.71	\$ 3.41	\$ 6.83	\$ 10.24	\$ 13.65	\$ 17.06	\$ 20.48	\$ 23.89	\$ 27.30	\$ 30.71
Supplier Market Price	\$ 0.01848 per kWh	\$ -	\$ 1.85	\$ 3.70	\$ 5.54	\$ 7.39	\$ 9.24	\$ 13.86	\$ 18.48	\$ 27.72	\$ 36.96	\$ 46.20	\$ 55.44	\$ 64.68	\$ 73.92	\$ 83.16	\$ 92.40
Monthly Bill		\$ 6.38	\$ 18.04	\$ 29.70	\$ 41.36	\$ 53.02	\$ 64.68	\$ 93.83	\$ 122.98	\$ 181.28	\$ 239.58	\$ 297.88	\$ 356.18	\$ 414.48	\$ 472.78	\$ 531.08	\$ 589.38
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

**DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GS/GMD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY**

MONTHLY DEMAND = 100 KW

Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Demand - kW	100	100	100	100	100	100	100	100	100	100	100
Usage - kWh	-	7,300	14,600	21,900	29,200	36,500	43,800	51,100	58,400	65,700	73,000

Rate GS/GM (bundled rate)

Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Capacity Charge												
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 18.34	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30	\$ 1,742.30
Energy Charge												
First 550 kWh	\$ 0.1397	\$ -	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84
Next 750 kWh	\$ 0.1309	\$ -	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18
Excess kWh	\$ 0.0380	\$ -	\$ 228.00	\$ 505.40	\$ 782.80	\$ 1,060.20	\$ 1,337.60	\$ 1,615.00	\$ 1,892.40	\$ 2,169.80	\$ 2,447.20	\$ 2,724.60
Monthly Total	\$ 1,751.37	\$ 2,154.38	\$ 2,431.78	\$ 2,709.18	\$ 2,986.58	\$ 3,263.98	\$ 3,541.38	\$ 3,818.78	\$ 4,096.18	\$ 4,373.58	\$ 4,650.98	

Supplier Market Price \$0.00 per kW
DLC Customer Gen. Charge/Credit 1.8640 cents per kWh

GSD/GMD CTC Calculation

Base Bill	\$ 1,751.37	\$ 2,154.38	\$ 2,431.78	\$ 2,709.18	\$ 2,986.58	\$ 3,263.98	\$ 3,541.38	\$ 3,818.78	\$ 4,096.18	\$ 4,373.58	\$ 4,650.98
Less:											
Customer Charge	\$ 9.07	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)
<u>Delivery Charges-Demand</u>											
Transmission											
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 0.93	\$ (88.62)	\$ (88.62)	\$ (88.62)	\$ (88.62)	\$ (88.62)	\$ (88.62)	\$ (88.62)	\$ (88.62)	\$ (88.62)	\$ (88.62)
Distribution											
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 4.45	\$ (422.33)	\$ (422.33)	\$ (422.33)	\$ (422.33)	\$ (422.33)	\$ (422.33)	\$ (422.33)	\$ (422.33)	\$ (422.33)	\$ (422.33)
CTC											
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 3.79	\$ (360.21)	\$ (360.21)	\$ (360.21)	\$ (360.21)	\$ (360.21)	\$ (360.21)	\$ (360.21)	\$ (360.21)	\$ (360.21)	\$ (360.21)
<u>Delivery Charges-Energy</u>											
Transmission											
First 550 kWh	\$ 0.0052	\$ -	\$ (2.87)	\$ (2.87)	\$ (2.87)	\$ (2.87)	\$ (2.87)	\$ (2.87)	\$ (2.87)	\$ (2.87)	\$ (2.87)
Next 750 kWh	\$ 0.0048	\$ -	\$ (3.57)	\$ (3.57)	\$ (3.57)	\$ (3.57)	\$ (3.57)	\$ (3.57)	\$ (3.57)	\$ (3.57)	\$ (3.57)
Excess kWh	\$ 0.0020	\$ -	\$ (11.82)	\$ (26.19)	\$ (40.57)	\$ (54.95)	\$ (69.32)	\$ (83.70)	\$ (98.07)	\$ (112.45)	\$ (126.83)
Distribution											
First 550 kWh	\$ 0.0248	\$ -	\$ (13.65)	\$ (13.65)	\$ (13.65)	\$ (13.65)	\$ (13.65)	\$ (13.65)	\$ (13.65)	\$ (13.65)	\$ (13.65)
Next 750 kWh	\$ 0.0227	\$ -	\$ (17.02)	\$ (17.02)	\$ (17.02)	\$ (17.02)	\$ (17.02)	\$ (17.02)	\$ (17.02)	\$ (17.02)	\$ (17.02)
Excess kWh	\$ 0.0094	\$ -	\$ (56.31)	\$ (124.83)	\$ (193.34)	\$ (261.86)	\$ (330.37)	\$ (398.89)	\$ (467.40)	\$ (535.92)	\$ (604.43)
Variable CTC											
First 550 kWh	\$ 0.0212	\$ -	\$ (11.65)	\$ (11.65)	\$ (11.65)	\$ (11.65)	\$ (11.65)	\$ (11.65)	\$ (11.65)	\$ (11.65)	\$ (11.65)
Next 750 kWh	\$ 0.0194	\$ -	\$ (14.52)	\$ (14.52)	\$ (14.52)	\$ (14.52)	\$ (14.52)	\$ (14.52)	\$ (14.52)	\$ (14.52)	\$ (14.52)
Excess kWh	\$ 0.0080	\$ -	\$ (48.03)	\$ (106.47)	\$ (164.90)	\$ (223.34)	\$ (281.78)	\$ (340.21)	\$ (398.65)	\$ (457.09)	\$ (515.52)
DLC Customer Gen. Charge/Credit	\$ 0.0186	\$ -	\$ (136.07)	\$ (272.14)	\$ (408.22)	\$ (544.29)	\$ (680.36)	\$ (816.43)	\$ (952.50)	\$ (1,088.58)	\$ (1,224.65)
Fixed CTC	\$ 871.15	\$ 958.66	\$ 958.66	\$ 958.66	\$ 958.66	\$ 958.66	\$ 958.66	\$ 958.66	\$ 958.66	\$ 958.66	\$ 958.66

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GS/GMD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY (continued)

MONTHLY DEMAND = 100 KW

Rate GS/GMD (proposed unbundled rate)

Duquesne Light Charges														
Customer Charge	\$	9.07	\$	9.07	\$	9.07	\$	9.07	\$	9.07	\$	9.07	\$	9.07
Fixed CTC			\$	871.15	\$	958.66	\$	958.66	\$	958.66	\$	958.66	\$	958.66
Delivery Charges-Demand														
Transmission														
First 5 kW	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Excess kW	\$	0.93	\$	88.62	\$	88.62	\$	88.62	\$	88.62	\$	88.62	\$	88.62
Distribution														
First 5 kW	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Excess kW	\$	4.45	\$	422.33	\$	422.33	\$	422.33	\$	422.33	\$	422.33	\$	422.33
CTC														
First 5 kW	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Excess kW	\$	3.79	\$	360.21	\$	360.21	\$	360.21	\$	360.21	\$	360.21	\$	360.21
Delivery Charges-Energy														
Transmission														
First 550 kWh	\$	0.0052	\$	-	\$	2.87	\$	2.87	\$	2.87	\$	2.87	\$	2.87
Next 750 kWh	\$	0.0048	\$	-	\$	3.57	\$	3.57	\$	3.57	\$	3.57	\$	3.57
Excess kWh	\$	0.0020	\$	-	\$	11.82	\$	26.19	\$	40.57	\$	54.95	\$	69.32
Distribution														
First 550 kWh	\$	0.0248	\$	-	\$	13.65	\$	13.65	\$	13.65	\$	13.65	\$	13.65
Next 750 kWh	\$	0.0227	\$	-	\$	17.02	\$	17.02	\$	17.02	\$	17.02	\$	17.02
Excess kWh	\$	0.0094	\$	-	\$	56.31	\$	124.83	\$	193.34	\$	261.86	\$	330.37
Variable CTC														
First 550 kWh	\$	0.0212	\$	-	\$	11.65	\$	11.65	\$	11.65	\$	11.65	\$	11.65
Next 750 kWh	\$	0.0194	\$	-	\$	14.52	\$	14.52	\$	14.52	\$	14.52	\$	14.52
Excess kWh	\$	0.0080	\$	-	\$	48.03	\$	106.47	\$	164.90	\$	223.34	\$	281.78
Supplier Market Price														
Demand	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Energy	\$	0.0186	\$	-	\$	136.07	\$	272.14	\$	408.22	\$	544.29	\$	680.36
Total Monthly Charges			\$	1,751.37	\$	2,154.38	\$	2,431.78	\$	2,709.18	\$	2,986.58	\$	3,263.98
Percent Change				0.00%		0.00%		0.00%		0.00%		0.00%		0.00%

**DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GMHD - GENERAL SERVICE MEDIUM HEATING DELIVERY - WINTER**

MONTHLY DEMAND = 250 kW

Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Demand - kW	250	250	250	250	250	250	250	250	250	250	250
Usage - kWh	-	18,250	36,500	54,750	73,000	91,250	109,500	127,750	146,000	164,250	182,500

Rate GMH (bundled rate)

Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Energy charge												
First 1,250 kWh plus 150 kWh for each kW over 6 kW	\$ 0.11460	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,337.61
Excess kWh	\$ 0.0380	\$ -	\$ -	\$ -	\$ 642.20	\$ 1,335.70	\$ 2,029.20	\$ 2,722.70	\$ 3,416.20	\$ 4,109.70	\$ 4,803.20	\$ 5,496.70
Total		\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,979.81	\$ 5,673.31	\$ 6,366.81	\$ 7,060.31	\$ 7,753.81	\$ 8,447.31	\$ 9,140.81	\$ 9,834.31

Supplier Market Price 50.00 per kW 1.855 cents per kWh
 DLC Customer Gen. Charge/Credit 1.855 cents per kWh

CTC Calculation

Base Bill		\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,979.81	\$ 5,673.31	\$ 6,366.81	\$ 7,060.31	\$ 7,753.81	\$ 8,447.31	\$ 9,140.81	\$ 9,834.31
Less:												
Customer Charge	\$ 9.07	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)
Delivery Charges-Energy												
Transmission												
First Block	\$ 0.0046	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)	\$ (172.23)
Excess kWh	\$ 0.0023	\$ -	\$ -	\$ -	\$ (38.60)	\$ (80.28)	\$ (121.96)	\$ (163.64)	\$ (205.32)	\$ (247.01)	\$ (288.69)	\$ (330.37)
Distribution												
First Block	\$ 0.0241	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)	\$ (914.00)
Excess kWh	\$ 0.0121	\$ -	\$ -	\$ -	\$ (204.84)	\$ (426.04)	\$ (647.25)	\$ (868.45)	\$ (1,089.65)	\$ (1,310.86)	\$ (1,532.06)	\$ (1,753.27)
Variable CTC												
First Block	\$ 0.0101	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)	\$ (380.46)
Excess kWh	\$ 0.0050	\$ -	\$ -	\$ -	\$ (85.27)	\$ (177.34)	\$ (269.42)	\$ (361.50)	\$ (453.58)	\$ (545.65)	\$ (637.73)	\$ (729.81)
DLC Customer Gen. Charge/Credit	\$ 0.0186	\$ -	\$ (338.54)	\$ (677.08)	\$ (1,015.61)	\$ (1,354.15)	\$ (1,692.69)	\$ (2,031.23)	\$ (2,369.76)	\$ (2,708.30)	\$ (3,046.84)	\$ (3,385.38)
Fixed CTC		\$ 2,861.85	\$ 2,523.32	\$ 2,184.78	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74

Rate GMHD (proposed unbundled rate)

Fixed CTC		\$ 2,861.85	\$ 2,523.32	\$ 2,184.78	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74	\$ 2,159.74
Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Delivery Charges-Energy												
Transmission												
First Block	\$ 0.0046	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23	\$ 172.23
Excess kWh	\$ 0.0023	\$ -	\$ -	\$ -	\$ 38.60	\$ 80.28	\$ 121.96	\$ 163.64	\$ 205.32	\$ 247.01	\$ 288.69	\$ 330.37
Distribution												
First Block	\$ 0.0241	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00	\$ 914.00
Excess kWh	\$ 0.0121	\$ -	\$ -	\$ -	\$ 204.84	\$ 426.04	\$ 647.25	\$ 868.45	\$ 1,089.65	\$ 1,310.86	\$ 1,532.06	\$ 1,753.27
Variable CTC												
First Block	\$ 0.0101	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46	\$ 380.46
Excess kWh	\$ 0.0050	\$ -	\$ -	\$ -	\$ 85.27	\$ 177.34	\$ 269.42	\$ 361.50	\$ 453.58	\$ 545.65	\$ 637.73	\$ 729.81
Supplier Market Price												
Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Energy	\$ 0.0186	\$ -	\$ 338.54	\$ 677.08	\$ 1,015.61	\$ 1,354.15	\$ 1,692.69	\$ 2,031.23	\$ 2,369.76	\$ 2,708.30	\$ 3,046.84	\$ 3,385.38
Total		\$ 4,337.61	\$ 4,337.61	\$ 4,337.61	\$ 4,979.81	\$ 5,673.31	\$ 6,366.81	\$ 7,060.31	\$ 7,753.81	\$ 8,447.31	\$ 9,140.81	\$ 9,834.31
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GMHD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY - SUMMER

MONTHLY DEMAND = **250 KW**

Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Demand - kW	250	250	250	250	250	250	250	250	250	250	250
Usage - kWh	18,250	36,500	54,750	73,000	91,250	109,500	127,750	146,000	164,250	182,500	

Rate GMHD (bundled rate, summer)

Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Capacity Charge												
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 18.34	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30	\$ 4,493.30
Energy Charge												
First 550 kWh	\$ 0.1397	\$ -	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84	\$ 76.84
Next 750 kWh	\$ 0.1309	\$ -	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18	\$ 98.18
Excess kWh	\$ 0.0380	\$ -	\$ 644.10	\$ 1,337.60	\$ 2,031.10	\$ 2,724.60	\$ 3,418.10	\$ 4,111.60	\$ 4,805.10	\$ 5,498.60	\$ 6,192.10	\$ 6,885.60
Monthly Total	\$ 4,502.37	\$ 5,321.48	\$ 6,014.98	\$ 6,708.48	\$ 7,401.98	\$ 8,095.48	\$ 8,788.98	\$ 9,482.48	\$ 10,175.98	\$ 10,869.48	\$ 11,562.98	

Supplier Market Price 50.00 per kW
 DLC Customer Gen. Charge/Credit 1.8550 cents per kWh

GMHD CTC Calculation (summer)

Base Bill	\$ 4,502.37	\$ 5,321.48	\$ 6,014.98	\$ 6,708.48	\$ 7,401.98	\$ 8,095.48	\$ 8,788.98	\$ 9,482.48	\$ 10,175.98	\$ 10,869.48	\$ 11,562.98
Less:											
Customer Charge	\$ 9.07	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)
<u>Delivery Charges-Demand</u>											
Transmission											
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 1.08	\$ (263.81)	\$ (263.81)	\$ (263.81)	\$ (263.81)	\$ (263.81)	\$ (263.81)	\$ (263.81)	\$ (263.81)	\$ (263.81)	\$ (263.81)
Distribution											
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 5.71	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)	\$ (1,400.05)
CTC											
First 5 kW	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Excess kW	\$ 2.38	\$ (582.78)	\$ (582.78)	\$ (582.78)	\$ (582.78)	\$ (582.78)	\$ (582.78)	\$ (582.78)	\$ (582.78)	\$ (582.78)	\$ (582.78)
<u>Delivery Charges-Energy</u>											
Transmission											
First 550 kWh	\$ 0.0060	\$ -	\$ (3.31)	\$ (3.31)	\$ (3.31)	\$ (3.31)	\$ (3.31)	\$ (3.31)	\$ (3.31)	\$ (3.31)	\$ (3.31)
Next 750 kWh	\$ 0.0055	\$ -	\$ (4.13)	\$ (4.13)	\$ (4.13)	\$ (4.13)	\$ (4.13)	\$ (4.13)	\$ (4.13)	\$ (4.13)	\$ (4.13)
Excess kWh	\$ 0.0023	\$ -	\$ (38.71)	\$ (80.39)	\$ (122.08)	\$ (163.76)	\$ (205.44)	\$ (247.12)	\$ (288.80)	\$ (330.48)	\$ (372.16)
Distribution											
First 550 kWh	\$ 0.0320	\$ -	\$ (17.58)	\$ (17.58)	\$ (17.58)	\$ (17.58)	\$ (17.58)	\$ (17.58)	\$ (17.58)	\$ (17.58)	\$ (17.58)
Next 750 kWh	\$ 0.0292	\$ -	\$ (21.92)	\$ (21.92)	\$ (21.92)	\$ (21.92)	\$ (21.92)	\$ (21.92)	\$ (21.92)	\$ (21.92)	\$ (21.92)
Excess kWh	\$ 0.0121	\$ -	\$ (205.45)	\$ (426.65)	\$ (647.85)	\$ (869.06)	\$ (1,090.26)	\$ (1,311.46)	\$ (1,532.67)	\$ (1,753.87)	\$ (1,975.07)
Variable CTC											
First 550 kWh	\$ 0.0133	\$ -	\$ (7.32)	\$ (7.32)	\$ (7.32)	\$ (7.32)	\$ (7.32)	\$ (7.32)	\$ (7.32)	\$ (7.32)	\$ (7.32)
Next 750 kWh	\$ 0.0122	\$ -	\$ (9.12)	\$ (9.12)	\$ (9.12)	\$ (9.12)	\$ (9.12)	\$ (9.12)	\$ (9.12)	\$ (9.12)	\$ (9.12)
Excess kWh	\$ 0.0050	\$ -	\$ (85.52)	\$ (177.60)	\$ (269.67)	\$ (361.75)	\$ (453.83)	\$ (545.91)	\$ (637.98)	\$ (730.06)	\$ (822.14)
DLC Customer Gen. Charge/Credit	\$ 0.0186	\$ -	\$ (338.54)	\$ (677.08)	\$ (1,015.61)	\$ (1,354.15)	\$ (1,692.69)	\$ (2,031.23)	\$ (2,369.76)	\$ (2,708.30)	\$ (3,046.84)
Fixed CTC	\$ 2,246.65	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16	\$ 2,334.16

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GMHD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY - SUMMER

MONTHLY DEMAND = 250 KW

Rate GMHD (proposed unbundled rate, summer)

Duquesne Light Charges														
Customer Charge	\$	9.07	\$	9.07	\$	9.07	\$	9.07	\$	9.07	\$	9.07	\$	9.07
Fixed CTC	\$	2,246.65	\$	2,334.16	\$	2,334.16	\$	2,334.16	\$	2,334.16	\$	2,334.16	\$	2,334.16
Delivery Charges-Demand														
Transmission														
First 5 kW	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Excess kW	\$	1.08	\$	263.81	\$	263.81	\$	263.81	\$	263.81	\$	263.81	\$	263.81
Distribution														
First 5 kW	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Excess kW	\$	5.71	\$	1,400.05	\$	1,400.05	\$	1,400.05	\$	1,400.05	\$	1,400.05	\$	1,400.05
CTC														
First 5 kW	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Excess kW	\$	2.38	\$	582.78	\$	582.78	\$	582.78	\$	582.78	\$	582.78	\$	582.78
Delivery Charges-Energy														
Transmission														
First 550 kWh	\$	0.0060	\$	-	\$	3.31	\$	3.31	\$	3.31	\$	3.31	\$	3.31
Next 750 kWh	\$	0.0055	\$	-	\$	4.13	\$	4.13	\$	4.13	\$	4.13	\$	4.13
Excess kWh	\$	0.0023	\$	-	\$	38.71	\$	80.39	\$	122.08	\$	163.76	\$	205.44
Distribution														
First 550 kWh	\$	0.0320	\$	-	\$	17.58	\$	17.58	\$	17.58	\$	17.58	\$	17.58
Next 750 kWh	\$	0.0292	\$	-	\$	21.92	\$	21.92	\$	21.92	\$	21.92	\$	21.92
Excess kWh	\$	0.0121	\$	-	\$	205.45	\$	426.65	\$	647.85	\$	869.06	\$	1,090.26
Variable CTC														
First 550 kWh	\$	0.0133	\$	-	\$	7.32	\$	7.32	\$	7.32	\$	7.32	\$	7.32
Next 750 kWh	\$	0.0122	\$	-	\$	9.12	\$	9.12	\$	9.12	\$	9.12	\$	9.12
Excess kWh	\$	0.0050	\$	-	\$	85.52	\$	177.60	\$	269.67	\$	361.75	\$	453.83
Supplier Market Price														
Demand	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Energy	\$	0.0186	\$	-	\$	338.54	\$	677.08	\$	1,015.61	\$	1,354.15	\$	1,692.69
Total Monthly Charges	\$	4,502.37	\$	5,321.48	\$	6,014.98	\$	6,708.48	\$	7,401.98	\$	8,095.48	\$	8,788.98
Percent Change		0.00%		0.00%		0.00%		0.00%		0.00%		0.00%		0.00%

**DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GLHD - GENERAL SERVICE LARGE HEATING DELIVERY - WINTER**

MONTHLY DEMAND = 500 KW

Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Demand - kW	500	500	500	500	500	500	500	500	500	500	500
Usage - kWh	-	36,500	73,000	109,500	146,000	182,500	219,000	255,500	292,000	328,500	365,000

Rate GLH (bundled rate)

Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Energy charge												
First 1,250 kWh plus 150 kWh for each kW over 6 kW	\$ 0.11460	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11
Excess kWh	\$ 0.0380	\$ -	\$ -	\$ -	\$ 1,297.70	\$ 2,684.70	\$ 4,071.70	\$ 5,458.70	\$ 6,845.70	\$ 8,232.70	\$ 9,619.70	\$ 11,006.70
Total		\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 9,932.81	\$ 11,319.81	\$ 12,706.81	\$ 14,093.81	\$ 15,480.81	\$ 16,867.81	\$ 18,254.81	\$ 19,641.81

Supplier Market Price \$0.00 per kW 1.858 cents per kWh
 DLC Customer Gen. Charge/Credit 1.858 cents per kWh

CTC Calculation

Base Bill	\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 9,932.81	\$ 11,319.81	\$ 12,706.81	\$ 14,093.81	\$ 15,480.81	\$ 16,867.81	\$ 18,254.81	\$ 19,641.81
Less:											
Customer Charge	\$ 9.07	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)
Delivery Charges-Energy											
Transmission											
First Block	\$ 0.0046	\$ (349.56)	\$ (349.56)	\$ (349.56)	\$ (349.56)	\$ (349.56)	\$ (349.56)	\$ (349.56)	\$ (349.56)	\$ (349.56)	\$ (349.56)
Excess kWh	\$ 0.0023	\$ -	\$ -	\$ -	\$ (79.46)	\$ (164.39)	\$ (249.32)	\$ (334.24)	\$ (419.17)	\$ (504.10)	\$ (589.03)
Distribution											
First Block	\$ 0.0145	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)	\$ (1,094.68)
Excess kWh	\$ 0.0073	\$ -	\$ -	\$ -	\$ (248.83)	\$ (514.79)	\$ (780.75)	\$ (1,046.71)	\$ (1,312.67)	\$ (1,578.62)	\$ (1,844.58)
Variable CTC											
First Block	\$ 0.0196	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)	\$ (1,473.30)
Excess kWh	\$ 0.0098	\$ -	\$ -	\$ -	\$ (334.90)	\$ (692.84)	\$ (1,050.79)	\$ (1,408.73)	\$ (1,766.68)	\$ (2,124.62)	\$ (2,482.57)
DLC Customer Gen. Charge/Credit	\$ 0.0186	\$ -	\$ (678.17)	\$ (1,356.34)	\$ (2,034.51)	\$ (2,712.68)	\$ (3,390.85)	\$ (4,069.02)	\$ (4,747.19)	\$ (5,425.36)	\$ (6,103.53)
Fixed CTC	\$ 5,708.49	\$ 5,030.32	\$ 4,352.15	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49

Rate GLHD (proposed unbundled rate)

Fixed CTC	\$ 5,708.49	\$ 5,030.32	\$ 4,352.15	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49	\$ 4,308.49
Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Delivery Charges-Energy											
Transmission											
First Block	\$ 0.0046	\$ 349.56	\$ 349.56	\$ 349.56	\$ 349.56	\$ 349.56	\$ 349.56	\$ 349.56	\$ 349.56	\$ 349.56	\$ 349.56
Excess kWh	\$ 0.0023	\$ -	\$ -	\$ -	\$ 79.46	\$ 164.39	\$ 249.32	\$ 334.24	\$ 419.17	\$ 504.10	\$ 589.03
Distribution											
First Block	\$ 0.0145	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68	\$ 1,094.68
Excess kWh	\$ 0.0073	\$ -	\$ -	\$ -	\$ 248.83	\$ 514.79	\$ 780.75	\$ 1,046.71	\$ 1,312.67	\$ 1,578.62	\$ 1,844.58
Variable CTC											
First Block	\$ 0.0196	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30	\$ 1,473.30
Excess kWh	\$ 0.0098	\$ -	\$ -	\$ -	\$ 334.90	\$ 692.84	\$ 1,050.79	\$ 1,408.73	\$ 1,766.68	\$ 2,124.62	\$ 2,482.57
Supplier Market Price											
Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Energy	\$ 0.0186	\$ -	\$ 678.17	\$ 1,356.34	\$ 2,034.51	\$ 2,712.68	\$ 3,390.85	\$ 4,069.02	\$ 4,747.19	\$ 5,425.36	\$ 6,103.53
Total		\$ 8,635.11	\$ 8,635.11	\$ 8,635.11	\$ 9,932.81	\$ 11,319.81	\$ 12,706.81	\$ 14,093.81	\$ 15,480.81	\$ 16,867.81	\$ 18,254.81
Percent Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

**DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GLHD - GENERAL SERVICE LARGE HEATING DELIVERY - SUMMER**

MONTHLY DEMAND = 500 KW

Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Demand - kW	500	500	500	500	500	500	500	500	500	500	500
Usage - kWh	-	36,500	73,000	109,500	146,000	182,500	219,000	255,500	292,000	328,500	365,000

Rate GLH (bundled rate, summer)

Capacity Charge												
First 300 kW	\$ 5,527	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00
Excess kW	\$ 13.98	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00
Energy charge												
All kWh	\$ 0.0380	\$ -	\$ 1,387.00	\$ 2,774.00	\$ 4,161.00	\$ 5,548.00	\$ 6,935.00	\$ 8,322.00	\$ 9,709.00	\$ 11,096.00	\$ 12,483.00	\$ 13,870.00
Total		\$ 8,323.00	\$ 9,710.00	\$ 11,097.00	\$ 12,484.00	\$ 13,871.00	\$ 15,258.00	\$ 16,645.00	\$ 18,032.00	\$ 19,419.00	\$ 20,806.00	\$ 22,193.00

Supplier Market Price \$0.00 per kW 1.858 cents per kWh
 DLC Customer Gen. Charge/Credit 1.858 cents per kWh

CTC Calculation

Base Bill	\$ 8,323.00	\$ 9,710.00	\$ 11,097.00	\$ 12,484.00	\$ 13,871.00	\$ 15,258.00	\$ 16,645.00	\$ 18,032.00	\$ 19,419.00	\$ 20,806.00	\$ 22,193.00	
Less:												
Fixed Charges-First 300 kW												
Transmission	\$ 662.21	\$ (662.21)	\$ (662.21)	\$ (662.21)	\$ (662.21)	\$ (662.21)	\$ (662.21)	\$ (662.21)	\$ (662.21)	\$ (662.21)	\$ (662.21)	
Distribution	\$ 2,073.77	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	\$ (2,073.77)	
CTC	\$ 2,791.02	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	\$ (2,791.02)	
Delivery Charges-Demand												
Transmission-per kW	\$ 0.84	\$ (167.50)	\$ (167.50)	\$ (167.50)	\$ (167.50)	\$ (167.50)	\$ (167.50)	\$ (167.50)	\$ (167.50)	\$ (167.50)	\$ (167.50)	
Distribution-per kW	\$ 2.62	\$ (524.54)	\$ (524.54)	\$ (524.54)	\$ (524.54)	\$ (524.54)	\$ (524.54)	\$ (524.54)	\$ (524.54)	\$ (524.54)	\$ (524.54)	
Variable CTC-per kW	\$ 3.53	\$ (705.96)	\$ (705.96)	\$ (705.96)	\$ (705.96)	\$ (705.96)	\$ (705.96)	\$ (705.96)	\$ (705.96)	\$ (705.96)	\$ (705.96)	
Delivery Charges-Energy												
Transmission-per kWh	\$ 0.0023	\$ -	\$ (84.93)	\$ (169.86)	\$ (254.78)	\$ (339.71)	\$ (424.64)	\$ (509.57)	\$ (594.49)	\$ (679.42)	\$ (764.35)	\$ (849.28)
Distribution-per kWh	\$ 0.0073	\$ -	\$ (265.98)	\$ (531.92)	\$ (797.87)	\$ (1,063.83)	\$ (1,329.79)	\$ (1,595.75)	\$ (1,861.70)	\$ (2,127.66)	\$ (2,393.62)	\$ (2,659.58)
Variable CTC-per kWh	\$ 0.0098	\$ -	\$ (357.94)	\$ (715.89)	\$ (1,073.83)	\$ (1,431.78)	\$ (1,789.72)	\$ (2,147.67)	\$ (2,505.61)	\$ (2,863.56)	\$ (3,221.50)	\$ (3,579.45)
DLC Customer Gen. Charge/Credit	\$ 0.0186	\$ -	\$ (678.17)	\$ (1,356.34)	\$ (2,034.51)	\$ (2,712.68)	\$ (3,390.85)	\$ (4,069.02)	\$ (4,747.19)	\$ (5,425.36)	\$ (6,103.53)	\$ (6,781.70)
Fixed CTC	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00

Rate GLHD (proposed unbundled rate, summer)

Fixed CTC	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	
Fixed Charges-First 300 kW												
Transmission	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	\$ 662.21	
Distribution	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	\$ 2,073.77	
CTC	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	\$ 2,791.02	
Delivery Charges-Demand												
Transmission-per kW	\$ 0.84	\$ 167.50	\$ 167.50	\$ 167.50	\$ 167.50	\$ 167.50	\$ 167.50	\$ 167.50	\$ 167.50	\$ 167.50	\$ 167.50	
Distribution-per kW	\$ 2.62	\$ 524.54	\$ 524.54	\$ 524.54	\$ 524.54	\$ 524.54	\$ 524.54	\$ 524.54	\$ 524.54	\$ 524.54	\$ 524.54	
Variable CTC-per kW	\$ 3.53	\$ 705.96	\$ 705.96	\$ 705.96	\$ 705.96	\$ 705.96	\$ 705.96	\$ 705.96	\$ 705.96	\$ 705.96	\$ 705.96	
Delivery Charges-Energy												
Transmission-per kWh	\$ 0.0023	\$ -	\$ 84.93	\$ 169.86	\$ 254.78	\$ 339.71	\$ 424.64	\$ 509.57	\$ 594.49	\$ 679.42	\$ 764.35	\$ 849.28
Distribution-per kWh	\$ 0.0073	\$ -	\$ 265.98	\$ 531.92	\$ 797.87	\$ 1,063.83	\$ 1,329.79	\$ 1,595.75	\$ 1,861.70	\$ 2,127.66	\$ 2,393.62	\$ 2,659.58
Variable CTC-per kWh	\$ 0.0098	\$ -	\$ 357.94	\$ 715.89	\$ 1,073.83	\$ 1,431.78	\$ 1,789.72	\$ 2,147.67	\$ 2,505.61	\$ 2,863.56	\$ 3,221.50	\$ 3,579.45
Supplier Market Price												
Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Energy	\$ 0.0186	\$ -	\$ 678.17	\$ 1,356.34	\$ 2,034.51	\$ 2,712.68	\$ 3,390.85	\$ 4,069.02	\$ 4,747.19	\$ 5,425.36	\$ 6,103.53	\$ 6,781.70
Total	\$ 8,323.00	\$ 9,710.00	\$ 11,097.00	\$ 12,484.00	\$ 13,871.00	\$ 15,258.00	\$ 16,645.00	\$ 18,032.00	\$ 19,419.00	\$ 20,806.00	\$ 22,193.00	
Percent Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

**DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE GLD - GENERAL SERVICE LARGE DELIVERY**

MONTHLY DEMAND = 500 KW

Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Demand - kW	500	500	500	500	500	500	500	500	500	500	500
Usage - kWh	-	38,500	73,000	109,500	146,000	182,500	218,000	255,500	292,000	328,500	385,000

Rate GL (bundled rate)

Capacity Charge												
First 300 kW	\$ 5,527	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00	\$ 5,527.00
Excess kW	\$ 13.98	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00	\$ 2,796.00
Energy charge												
All kWh	\$ 0.0380	\$ -	\$ 1,387.00	\$ 2,774.00	\$ 4,161.00	\$ 5,548.00	\$ 6,935.00	\$ 8,322.00	\$ 9,709.00	\$ 11,096.00	\$ 12,483.00	\$ 13,870.00
Total		\$ 8,323.00	\$ 9,710.00	\$ 11,097.00	\$ 12,484.00	\$ 13,871.00	\$ 15,258.00	\$ 16,645.00	\$ 18,032.00	\$ 19,419.00	\$ 20,806.00	\$ 22,193.00

Supplier Market Price \$0.00 per kW 1,852 cents per kWh
 DLC Customer Gen. Charge/Credit 1,852 cents per kWh

CTC Calculation

Base Bill	\$ 8,323.00	\$ 9,710.00	\$ 11,097.00	\$ 12,484.00	\$ 13,871.00	\$ 15,258.00	\$ 16,645.00	\$ 18,032.00	\$ 19,419.00	\$ 20,806.00	\$ 22,193.00	
Less:												
<u>Fixed Charges-First 300 kW</u>												
Transmission	\$ 429.56	\$ (429.56)	\$ (429.56)	\$ (429.56)	\$ (429.56)	\$ (429.56)	\$ (429.56)	\$ (429.56)	\$ (429.56)	\$ (429.56)	\$ (429.56)	
Distribution	\$ 1,546.19	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	\$ (1,546.19)	
CTC	\$ 3,551.25	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	\$ (3,551.25)	
<u>Delivery Charges-Demand</u>												
Transmission-per kW	\$ 0.54	\$ (108.65)	\$ (108.65)	\$ (108.65)	\$ (108.65)	\$ (108.65)	\$ (108.65)	\$ (108.65)	\$ (108.65)	\$ (108.65)	\$ (108.65)	
Distribution-per kW	\$ 1.98	\$ (391.09)	\$ (391.09)	\$ (391.09)	\$ (391.09)	\$ (391.09)	\$ (391.09)	\$ (391.09)	\$ (391.09)	\$ (391.09)	\$ (391.09)	
Variable CTC-per kW	\$ 4.49	\$ (898.25)	\$ (898.25)	\$ (898.25)	\$ (898.25)	\$ (898.25)	\$ (898.25)	\$ (898.25)	\$ (898.25)	\$ (898.25)	\$ (898.25)	
<u>Delivery Charges-Energy</u>												
Transmission-per kWh	\$ 0.0015	\$ -	\$ (55.28)	\$ (110.52)	\$ (165.78)	\$ (221.04)	\$ (276.30)	\$ (331.56)	\$ (386.82)	\$ (442.08)	\$ (497.35)	\$ (552.61)
Distribution-per kWh	\$ 0.0054	\$ -	\$ (198.91)	\$ (397.82)	\$ (596.73)	\$ (795.64)	\$ (994.55)	\$ (1,193.46)	\$ (1,392.37)	\$ (1,591.28)	\$ (1,790.19)	\$ (1,989.10)
Variable CTC-per kWh	\$ 0.0125	\$ -	\$ (456.85)	\$ (913.70)	\$ (1,370.55)	\$ (1,827.40)	\$ (2,284.25)	\$ (2,741.10)	\$ (3,197.95)	\$ (3,654.80)	\$ (4,111.65)	\$ (4,568.50)
DLC Customer Gen. Charge/Credit	\$ 0.0185	\$ -	\$ (675.98)	\$ (1,351.96)	\$ (2,027.94)	\$ (2,703.92)	\$ (3,379.90)	\$ (4,055.88)	\$ (4,731.86)	\$ (5,407.84)	\$ (6,083.82)	\$ (6,759.80)
Fixed CTC	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	

Rate GLD (proposed unbundled rate)

Fixed CTC	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	\$ 1,398.00	
<u>Fixed Charges-First 300 kW</u>												
Transmission	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	\$ 429.56	
Distribution	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	\$ 1,546.19	
CTC	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	\$ 3,551.25	
<u>Delivery Charges-Demand</u>												
Transmission-per kW	\$ 0.54	\$ 108.65	\$ 108.65	\$ 108.65	\$ 108.65	\$ 108.65	\$ 108.65	\$ 108.65	\$ 108.65	\$ 108.65	\$ 108.65	
Distribution-per kW	\$ 1.98	\$ 391.09	\$ 391.09	\$ 391.09	\$ 391.09	\$ 391.09	\$ 391.09	\$ 391.09	\$ 391.09	\$ 391.09	\$ 391.09	
Variable CTC-per kW	\$ 4.49	\$ 898.25	\$ 898.25	\$ 898.25	\$ 898.25	\$ 898.25	\$ 898.25	\$ 898.25	\$ 898.25	\$ 898.25	\$ 898.25	
<u>Delivery Charges-Energy</u>												
Transmission-per kWh	\$ 0.0015	\$ -	\$ 55.28	\$ 110.52	\$ 165.78	\$ 221.04	\$ 276.30	\$ 331.56	\$ 386.82	\$ 442.08	\$ 497.35	\$ 552.61
Distribution-per kWh	\$ 0.0054	\$ -	\$ 198.91	\$ 397.82	\$ 596.73	\$ 795.64	\$ 994.55	\$ 1,193.46	\$ 1,392.37	\$ 1,591.28	\$ 1,790.19	\$ 1,989.10
Variable CTC-per kWh	\$ 0.0125	\$ -	\$ 456.85	\$ 913.70	\$ 1,370.55	\$ 1,827.40	\$ 2,284.25	\$ 2,741.10	\$ 3,197.95	\$ 3,654.80	\$ 4,111.65	\$ 4,568.50
Supplier Market Price												
Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
Energy	\$ 0.0185	\$ -	\$ 675.98	\$ 1,351.96	\$ 2,027.94	\$ 2,703.92	\$ 3,379.90	\$ 4,055.88	\$ 4,731.86	\$ 5,407.84	\$ 6,083.82	\$ 6,759.80
Total	\$ 8,323.00	\$ 9,710.00	\$ 11,097.00	\$ 12,484.00	\$ 13,871.00	\$ 15,258.00	\$ 16,645.00	\$ 18,032.00	\$ 19,419.00	\$ 20,806.00	\$ 22,193.00	
Percent Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE LD - LARGE POWER SERVICE DELIVERY

MONTHLY DEMAND = 46,000 KW

Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Demand - kW	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000	45,000
First 5000 kW	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Next 10,000 kW	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Next 25,000 kW	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Excess kW	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Usage - kWh	-	3,285,000	6,570,000	9,855,000	13,140,000	16,425,000	19,710,000	22,995,000	26,280,000	29,565,000	32,850,000
First 750,000 kWh + 400 kWh per kW	-	3,285,000	6,570,000	9,855,000	13,140,000	16,425,000	18,750,000	18,750,000	18,750,000	18,750,000	18,750,000
Next 150 kWh per kW	-	-	-	-	-	-	960,000	4,245,000	6,750,000	6,750,000	6,750,000
Excess kWh	-	-	-	-	-	-	-	-	780,000	4,065,000	7,350,000

Rate L (current bundled rate)

Capacity Charge												
First 5000 kW	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00	\$ 71,289.00
Next 10,000 kW	\$ 11.45 per kW	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00	\$ 114,500.00
Next 25,000 kW	\$ 11.13 per kW	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00	\$ 278,250.00
Excess kW	\$ 10.84 per kW	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00	\$ 54,200.00
Energy Charge												
First 750,000 kWh + 400 kWh per kW	\$ 0.0380 per kWh	\$ -	\$ 124,830.00	\$ 249,660.00	\$ 374,490.00	\$ 499,320.00	\$ 624,150.00	\$ 748,980.00	\$ 873,810.00	\$ 998,640.00	\$ 1,123,470.00	\$ 1,248,300.00
Next 150 kWh per kW	\$ 0.0255 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 24,576.00	\$ 108,672.00	\$ 192,816.00	\$ 277,968.00	\$ 363,120.00
Excess kWh	\$ 0.0234 per kWh	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 18,252.00	\$ 95,121.00	\$ 171,990.00	\$ 248,859.00
Total Monthly Bill		\$ 518,239.00	\$ 643,069.00	\$ 767,899.00	\$ 892,729.00	\$ 1,017,559.00	\$ 1,142,389.00	\$ 1,267,215.00	\$ 1,392,041.00	\$ 1,516,791.00	\$ 1,641,541.00	\$ 1,766,291.00

DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE LD - LARGE POWER SERVICE DELIVERY (continued)

MONTHLY DEMAND = 45,000 KW

Rate LD (proposed unbundled rate)

Fixed Charges																
Fixed CTC		\$	223,475.00	\$	223,475.00	\$	223,475.00	\$	223,475.00	\$	223,475.00	\$	223,475.00	\$	223,475.00	
First 5000 kW																
Transmission	\$	6,797.70	\$	6,797.70	\$	6,797.70	\$	6,797.70	\$	6,797.70	\$	6,797.70	\$	6,797.70	\$	6,797.70
Distribution	\$	21,616.25	\$	21,616.25	\$	21,616.25	\$	21,616.25	\$	21,616.25	\$	21,616.25	\$	21,616.25	\$	21,616.25
CTC	\$	42,875.05	\$	42,875.05	\$	42,875.05	\$	42,875.05	\$	42,875.05	\$	42,875.05	\$	42,875.05	\$	42,875.05
Delivery Charges-Demand																
Next 10,000 kW																
Transmission	\$	0.55 per kW	\$	5,459.02	\$	5,459.02	\$	5,459.02	\$	5,459.02	\$	5,459.02	\$	5,459.02	\$	5,459.02
Distribution	\$	1.74 per kW	\$	17,359.35	\$	17,359.35	\$	17,359.35	\$	17,359.35	\$	17,359.35	\$	17,359.35	\$	17,359.35
Variable CTC	\$	3.44 per kW	\$	34,431.63	\$	34,431.63	\$	34,431.63	\$	34,431.63	\$	34,431.63	\$	34,431.63	\$	34,431.63
Next 25,000 kW																
Transmission	\$	0.53 per kW	\$	13,266.14	\$	13,266.14	\$	13,266.14	\$	13,266.14	\$	13,266.14	\$	13,266.14	\$	13,266.14
Distribution	\$	1.69 per kW	\$	42,185.49	\$	42,185.49	\$	42,185.49	\$	42,185.49	\$	42,185.49	\$	42,185.49	\$	42,185.49
Variable CTC	\$	3.35 per kW	\$	83,673.37	\$	83,673.37	\$	83,673.37	\$	83,673.37	\$	83,673.37	\$	83,673.37	\$	83,673.37
Additional kW																
Transmission	\$	0.52 per kW	\$	2,584.10	\$	2,584.10	\$	2,584.10	\$	2,584.10	\$	2,584.10	\$	2,584.10	\$	2,584.10
Distribution	\$	1.64 per kW	\$	8,217.26	\$	8,217.26	\$	8,217.26	\$	8,217.26	\$	8,217.26	\$	8,217.26	\$	8,217.26
Variable CTC	\$	3.26 per kW	\$	16,298.64	\$	16,298.64	\$	16,298.64	\$	16,298.64	\$	16,298.64	\$	16,298.64	\$	16,298.64
Delivery Charges-Energy																
First 750,000 kWh +																
400 kWh per kW																
Transmission	\$	0.00186 per kWh	\$	-	\$	6,117.54	\$	12,235.08	\$	18,352.62	\$	24,470.17	\$	30,587.71	\$	34,917.47
Distribution	\$	0.00592 per kWh	\$	-	\$	19,453.40	\$	38,906.80	\$	58,360.20	\$	77,813.60	\$	97,267.00	\$	111,035.39
Variable CTC	\$	0.01175 per kWh	\$	-	\$	38,585.11	\$	77,170.22	\$	115,755.33	\$	154,340.43	\$	192,925.54	\$	220,234.64
Next 150 kWh per kW																
Transmission	\$	0.00068	\$	-	\$	-	\$	-	\$	-	\$	652.68	\$	2,886.07	\$	4,589.15
Distribution	\$	0.00216 per kWh	\$	-	\$	-	\$	-	\$	-	\$	2,075.48	\$	9,177.52	\$	14,593.22
Variable CTC	\$	0.00429 per kWh	\$	-	\$	-	\$	-	\$	-	\$	4,116.64	\$	18,203.27	\$	28,945.12
Excess kWh																
Transmission	\$	0.00047	\$	-	\$	-	\$	-	\$	-	\$	-	\$	366.67	\$	1,910.94
Distribution	\$	0.00149 per kWh	\$	-	\$	-	\$	-	\$	-	\$	-	\$	1,166.00	\$	6,076.67
Variable CTC	\$	0.00297 per kWh	\$	-	\$	-	\$	-	\$	-	\$	-	\$	2,312.72	\$	12,052.85
Supplier Market Price																
Demand	\$	0.00	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Energy	\$	0.01847 per kWh	\$	-	\$	60,673.95	\$	121,347.90	\$	182,021.85	\$	242,695.80	\$	303,369.75	\$	364,043.70
Total Monthly Bill			\$	518,239.00	\$	643,069.00	\$	767,899.00	\$	892,729.00	\$	1,017,559.00	\$	1,142,389.00	\$	1,255,315.00
Percent Change				0.00%		0.00%		0.00%		0.00%		0.00%		0.00%		0.00%

DUQUESNE LIGHT COMPANY
 COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
 RATE HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY (continued)

MONTHLY DEMAND = 70,000 KW

Rate HVPSD (proposed unbundled rate)

Fixed Charges																									
CTC		\$	(0.00)	\$	(7,654.78)	\$	(15,309.56)	\$	(22,964.34)	\$	(30,619.12)	\$	(38,273.90)	\$	(45,928.68)	\$	(53,583.46)	\$	(61,238.24)	\$	(68,893.02)	\$	(76,547.80)		
<u>First 30,000 kW</u>																									
Transmission	\$	37,954.56		\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56	\$	37,954.56
Distribution	\$	76,367.59		\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59	\$	76,367.59
CTC	\$	216,213.85		\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85	\$	216,213.85
<u>Delivery Charges - Demand</u>																									
Additional on-peak kW																									
Transmission	\$	1.37	per kW	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67	\$	54,749.67
Distribution	\$	2.75	per kW	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67	\$	110,160.67
Variable CTC	\$	7.80	per kW	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66	\$	311,889.66
<u>Delivery Charges - Energy</u>																									
On-Peak																									
Transmission	\$	0.00302	per kWh	\$	-	\$	10,809.79	\$	21,619.57	\$	32,429.36	\$	43,239.14	\$	54,048.93	\$	64,858.71	\$	75,668.50	\$	86,478.28	\$	97,288.07	\$	108,097.85
Distribution	\$	0.00608	per kWh	\$	-	\$	21,750.14	\$	43,500.29	\$	65,250.43	\$	87,000.58	\$	108,750.72	\$	130,500.86	\$	152,251.01	\$	174,001.15	\$	195,751.30	\$	217,501.44
Variable CTC	\$	0.01722	per kWh	\$	-	\$	61,579.56	\$	123,159.11	\$	184,738.67	\$	246,318.23	\$	307,897.78	\$	369,477.34	\$	431,056.90	\$	492,636.45	\$	554,216.01	\$	615,795.57
Off-Peak																									
Transmission	\$	0.00059	per kWh	\$	-	\$	900.92	\$	1,801.85	\$	2,702.77	\$	3,603.69	\$	4,504.62	\$	5,405.54	\$	6,306.46	\$	7,207.38	\$	8,108.31	\$	9,009.23
Distribution	\$	0.00118	per kWh	\$	-	\$	1,812.73	\$	3,625.46	\$	5,438.19	\$	7,250.91	\$	9,063.64	\$	10,876.37	\$	12,689.10	\$	14,501.83	\$	16,314.56	\$	18,127.28
Variable CTC	\$	0.00335	per kWh	\$	-	\$	5,132.24	\$	10,264.49	\$	15,396.73	\$	20,528.97	\$	25,661.21	\$	30,793.46	\$	35,925.70	\$	41,057.94	\$	46,190.18	\$	51,322.43
<u>Supplier Market Price</u>																									
Demand		50.00	per kW	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
Energy	\$	0.01848	per kWh	\$	-	\$	94,432.80	\$	188,865.60	\$	283,298.40	\$	377,731.20	\$	472,164.00	\$	566,596.80	\$	661,029.60	\$	755,462.40	\$	849,895.20	\$	944,328.00
Monthly Bill				\$	807,336.00	\$	996,099.40	\$	1,184,862.80	\$	1,373,626.20	\$	1,562,389.60	\$	1,751,153.00	\$	1,939,916.40	\$	2,128,679.80	\$	2,317,443.20	\$	2,506,206.60	\$	2,694,970.00
Percent Change				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

**DUQUESNE LIGHT COMPANY
COMPARISON BETWEEN BUNDLED AND UNBUNDLED RATES
RATE ALD - ARCHITECTURAL LIGHTING SERVICE DELIVERY**

MONTHLY DEMAND =	10 KW											
Load Factor	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
Demand - KW	10	10	10	10	10	10	10	10	10	10	10	10
Usage - kWh	-	730	1,460	2,190	2,920	3,650	4,380	5,110	5,840	6,570	7,300	

Rate AL (bundled rate)	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Capacity Charge												
All kW	\$ 7.02	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20	\$ 70.20
Energy Charge												
First 300 kWh	\$ 0.1006	\$ -	\$ 30.18	\$ 30.18	\$ 30.18	\$ 30.18	\$ 30.18	\$ 30.18	\$ 30.18	\$ 30.18	\$ 30.18	\$ 30.18
Excess kWh	\$ 0.0277	\$ -	\$ 11.91	\$ 32.13	\$ 52.35	\$ 72.57	\$ 92.80	\$ 113.02	\$ 133.24	\$ 153.46	\$ 173.68	\$ 193.90
Monthly Total	\$ 79.27	\$ 121.36	\$ 141.58	\$ 161.80	\$ 182.02	\$ 202.25	\$ 222.47	\$ 242.69	\$ 262.91	\$ 283.13	\$ 303.35	

Supplier Market Price	50.00 per kW	1.8140 cents per kWh										
DLC Customer Gen. Charge/Credit		1.8140 cents per kWh										
CTC Calculation												
Base Bill	\$ 79.27	\$ 121.36	\$ 141.58	\$ 161.80	\$ 182.02	\$ 202.25	\$ 222.47	\$ 242.69	\$ 262.91	\$ 283.13	\$ 303.35	
Less:												
Customer Charge	\$ 9.07	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)	\$ (9.07)
Delivery Charges-Demand												
Transmission	\$ 0.30	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)	\$ (2.97)
Distribution	\$ 1.88	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)	\$ (18.80)
CTC	\$ 1.33	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)	\$ (13.33)
Delivery Charges-Energy												
Transmission												
First 300 kWh	\$ 0.0027	\$ -	\$ (0.82)	\$ (0.82)	\$ (0.82)	\$ (0.82)	\$ (0.82)	\$ (0.82)	\$ (0.82)	\$ (0.82)	\$ (0.82)	\$ (0.82)
Excess kWh	\$ 0.0008	\$ -	\$ (0.35)	\$ (0.94)	\$ (1.53)	\$ (2.12)	\$ (2.71)	\$ (3.30)	\$ (3.89)	\$ (4.48)	\$ (5.07)	\$ (5.67)
Distribution												
First 300 kWh	\$ 0.0172	\$ -	\$ (5.17)	\$ (5.17)	\$ (5.17)	\$ (5.17)	\$ (5.17)	\$ (5.17)	\$ (5.17)	\$ (5.17)	\$ (5.17)	\$ (5.17)
Excess kWh	\$ 0.0051	\$ -	\$ (2.20)	\$ (5.94)	\$ (9.68)	\$ (13.42)	\$ (17.15)	\$ (20.89)	\$ (24.63)	\$ (28.37)	\$ (32.11)	\$ (35.84)
Variable CTC												
First 300 kWh	\$ 0.0122	\$ -	\$ (3.66)	\$ (3.66)	\$ (3.66)	\$ (3.66)	\$ (3.66)	\$ (3.66)	\$ (3.66)	\$ (3.66)	\$ (3.66)	\$ (3.66)
Excess kWh	\$ 0.0036	\$ -	\$ (1.56)	\$ (4.21)	\$ (6.86)	\$ (9.51)	\$ (12.16)	\$ (14.81)	\$ (17.46)	\$ (20.11)	\$ (22.76)	\$ (25.41)
DLC Customer Gen. Charge/Credit	\$ 0.0181	\$ -	\$ (13.24)	\$ (26.48)	\$ (39.73)	\$ (52.97)	\$ (66.21)	\$ (79.45)	\$ (92.70)	\$ (105.94)	\$ (119.18)	\$ (132.42)
Fixed CTC	\$ 35.10	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19

Rate ALD (proposed unbundled rate)	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	
Fixed Charges												
Customer Charge	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07	\$ 9.07
Fixed CTC	\$ 35.10	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19	\$ 50.19
Delivery Charges-Demand												
Transmission	\$ 0.30	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97	\$ 2.97
Distribution	\$ 1.88	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80	\$ 18.80
CTC	\$ 1.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33	\$ 13.33
Delivery Charges-Energy												
Transmission												
First 300 kWh	\$ 0.0027	\$ -	\$ 0.82	\$ 0.82	\$ 0.82	\$ 0.82	\$ 0.82	\$ 0.82	\$ 0.82	\$ 0.82	\$ 0.82	\$ 0.82
Excess kWh	\$ 0.0008	\$ -	\$ 0.35	\$ 0.94	\$ 1.53	\$ 2.12	\$ 2.71	\$ 3.30	\$ 3.89	\$ 4.48	\$ 5.07	\$ 5.67
Distribution												
First 300 kWh	\$ 0.0172	\$ -	\$ 5.17	\$ 5.17	\$ 5.17	\$ 5.17	\$ 5.17	\$ 5.17	\$ 5.17	\$ 5.17	\$ 5.17	\$ 5.17
Excess kWh	\$ 0.0051	\$ -	\$ 2.20	\$ 5.94	\$ 9.68	\$ 13.42	\$ 17.15	\$ 20.89	\$ 24.63	\$ 28.37	\$ 32.11	\$ 35.84
Variable CTC												
First 300 kWh	\$ 0.0122	\$ -	\$ 3.66	\$ 3.66	\$ 3.66	\$ 3.66	\$ 3.66	\$ 3.66	\$ 3.66	\$ 3.66	\$ 3.66	\$ 3.66
Excess kWh	\$ 0.0036	\$ -	\$ 1.56	\$ 4.21	\$ 6.86	\$ 9.51	\$ 12.16	\$ 14.81	\$ 17.46	\$ 20.11	\$ 22.76	\$ 25.41
Supplier Market Price												
Demand	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Energy	\$ 0.0181	\$ -	\$ 13.24	\$ 26.48	\$ 39.73	\$ 52.97	\$ 66.21	\$ 79.45	\$ 92.70	\$ 105.94	\$ 119.18	\$ 132.42
Total Monthly Charges	\$ 79.27	\$ 121.36	\$ 141.58	\$ 161.80	\$ 182.02	\$ 202.25	\$ 222.47	\$ 242.69	\$ 262.91	\$ 283.13	\$ 303.35	
Percent Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

Potential Stranded Cost Mitigation Resulting From Rate Redesign¹
(Millions of Dollars Each Year)

	<u>Incremental Stranded Cost Mitigation</u> [1]	<u>Foregone Revenues</u> [2]	<u>Net Stranded Cost Mitigation</u> [1] - [2]
Residential	9.3	0.3	9.0
Commercial & Industrial	<u>8.1</u>	<u>1.5</u>	<u>6.6</u>
Total	17.4	1.8	15.6

¹ Based on a 50% reduction in most demand and energy usage charges and price elasticities of -0.1 for energy and -0.5 for demand.

**RATE REDUCTION ON INCREMENTAL USAGE –
COMPARISON OF BUNDLED AND UNBUNDLED USAGE RATES (1)**

Customers In This <u>Rate Class</u>		<u>Current Bundled Usage Rates</u>	<u>Proposed Unbundled Usage Rates</u>	This Represents A Reduction On <u>Incremental Usage Of</u>
		Currently Pay This Much For Incremental <u>Usage</u> (cents per kWh)	Will Pay This Much For Incremental <u>Usage</u> (cents per kWh) (2)	
<u>Residential</u>				
RS		11.66	5.83	50%
RH				
Summer		11.66	5.83	50%
Winter	(3)	4.49	4.49	0%
RA				
Summer		11.66	5.83	50%
Winter	(3)	4.49	4.49	0%
<u>Commercial & Industrial</u>				
GS/GM	(3)	10.57	7.19	32%
GMH				
Summer	(3)	10.70	7.25	32%
Winter	(3)	3.80	3.80	0%
GLH				
Summer		7.39	5.60	24%
Winter		3.80	3.80	0%
GL		7.15	5.47	23%
L	(4)	5.93	4.87	18%
HVPS	(5)	4.97	4.97	0%
SE		11.02	11.02	0%
MTS		3.63	3.63	0%
AL		5.37	4.07	<u>24%</u>

Weighted Average Reduction in Incremental Usage Rate = **27% (7)**

- (1) Total usage rates by class are equal to the sum of energy charges and the effective demand charge rate (if applicable).
The effective demand charge rate is computed by dividing the demand charge by the associated monthly consumption (i.e., the average class load factor times the number of hours in the month).
- (2) Includes usage delivery charges (T, D and variable CTC) and CGC.
- (3) Assumes all customers are in the tailblock rate. Customers in initial blocks would experience greater reductions.
- (4) Assumes all customers are in the first block of energy and the second block of demand.
- (5) Off peak kWh price. Both on and off-peak rates have not changed.
- (6) Rate schedules SM and SH have not been unbundled and are not shown.
- (7) Weighted by kWh sales by class and by season.

Mitigation Sensitivity Analysis:
Changes in Energy and Demand Price Elasticities

Potential Stranded Cost Mitigation Resulting From Rate Redesign¹
(Millions of Dollars Each Year)

Demand Elasticity	Energy Elasticity					
	-0.05	-0.10	-0.15	-0.20	-0.30	-0.40
-0.010	5.5	12.2	19.1	26.2	41.0	56.8
-0.025	6.7	13.4	20.3	27.4	42.3	58.0
-0.050	8.9	15.6	22.5	29.6	44.4	60.2
-0.075	11.1	17.8	24.8	31.9	46.7	62.5
-0.100	13.5	20.2	27.1	34.3	49.1	64.9
-0.150	18.6	25.3	32.2	39.3	54.1	69.9

¹ Based on a 50% reduction in most demand and energy usage charges.

Mitigation Sensitivity Analysis:
Changes in Percentage Reduction in Most Demand and Energy Charges

Potential Stranded Cost Mitigation Resulting From Rate Redesign¹
(Millions of Dollars Each Year)

Reduction in Most Demand and Energy Charges

<u>25%</u>	<u>50%</u>	<u>75%</u>
\$10.2	\$15.6	\$12.3

¹ Based on price elasticities of -0.1 for energy and -0.05 for demand.

COMPARISON OF CURRENT BUNDLED AND PROPOSED UNBUNDLED USAGE RATES (1)

Rate	Current Bundled Usage Rates (2)	Unbundled Usage Delivery Charges					Market Based CGC (3)	Total Proposed Unbundled Usage Rate CGC+(T+D+C)	Reduction: Current Versus Proposed Usage Rate	Percent Reduction In Usage Rate
		Transmission T	Distribution D	Variable Class-Specific CTC (3) C	Usage Delivery Charges Subtotal (T+D+C)					
RS	All kWh	\$0.1166	\$0.0045	\$0.0281	\$0.0072	\$0.0397	\$0.01856	\$0.0583	\$0.0583	50%
RH										
Summer	First 500 kWh	\$0.1166	\$0.0052	\$0.0316	\$0.0030	\$0.0399	\$0.01844	\$0.0583	\$0.0583	50%
	Excess kWh	\$0.1166	\$0.0052	\$0.0316	\$0.0030	\$0.0399	\$0.01844	\$0.0583	\$0.0583	50%
Winter	First 500 kWh	\$0.1166	\$0.0052	\$0.0316	\$0.0030	\$0.0399	\$0.01844	\$0.0583	\$0.0583	50%
	Excess kWh	\$0.0449	\$0.0035	\$0.0210	\$0.0020	\$0.0265	\$0.01844	\$0.0449	\$0	0%
RA										
Summer	First 500 kWh	\$0.1166	\$0.0051	\$0.0279	\$0.0068	\$0.0398	\$0.01848	\$0.0583	\$0.0583	50%
	Excess kWh	\$0.1166	\$0.0051	\$0.0279	\$0.0068	\$0.0398	\$0.01848	\$0.0583	\$0.0583	50%
Winter	First 500 kWh	\$0.1166	\$0.0051	\$0.0279	\$0.0068	\$0.0398	\$0.01848	\$0.0583	\$0.0583	50%
	Excess kWh	\$0.0449	\$0.0034	\$0.0185	\$0.0045	\$0.0264	\$0.01848	\$0.0449	\$0	0%
GS/GM										
	First 5 kW	\$0	\$0	\$0	\$0	\$0		\$0	\$0	0%
	Additional kW	\$18.34	\$0.93	\$4.45	\$3.79	\$9.17		\$9.17	\$9.17	50%
	First 550 kWh	\$0.1397	\$0.0052	\$0.0248	\$0.0212	\$0.0512	\$0.01864	\$0.0699	\$0.0699	50%
	Next 750 kWh	\$0.1309	\$0.0048	\$0.0227	\$0.0194	\$0.0468	\$0.01864	\$0.0655	\$0.0655	50%
	Additional kWh	\$0.0380	\$0.0020	\$0.0094	\$0.0080	\$0.0194	\$0.01864	\$0.0380	\$0	0%
GMH										
Summer	First 5 kW	\$0	\$0	\$0	\$0	\$0		\$0	\$0	0%
	Additional kW	\$18.34	\$1.08	\$5.71	\$2.38	\$9.17		\$9.17	\$9.17	50%
	First 550 kWh	\$0.1397	\$0.0060	\$0.0320	\$0.0133	\$0.0513	\$0.01855	\$0.0699	\$0.0699	50%
	Next 750 kWh	\$0.1309	\$0.0055	\$0.0292	\$0.0122	\$0.0469	\$0.01855	\$0.0655	\$0.0655	50%
	Additional kWh	\$0.0380	\$0.0023	\$0.0121	\$0.0050	\$0.0195	\$0.01855	\$0.0380	\$0	0%
Winter	First Block	\$0.1146	\$0.0046	\$0.0241	\$0.0101	\$0.0388	\$0.01855	\$0.0573	\$0.0573	50%
	Additional kWh	\$0.0380	\$0.0023	\$0.0121	\$0.0050	\$0.0195	\$0.01855	\$0.0380	\$0	0%
GLH										
Summer	First 300 kW	\$5,527.00	\$662.21	\$2,073.77	\$2,791.02	\$5,527.00		\$5,527.00	\$0	0%
	Additional kW	\$13.98	\$0.84	\$2.62	\$3.53	\$6.99		\$6.99	\$6.99	50%
	All kWh	\$0.0380	\$0.0023	\$0.0073	\$0.0098	\$0.0194	\$0.01858	\$0.0380	\$0	0%
Winter	First Block	\$0.1146	\$0.0046	\$0.0145	\$0.0196	\$0.0387	\$0.01858	\$0.0573	\$0.0573	50%
	Additional kWh	\$0.0380	\$0.0023	\$0.0073	\$0.0098	\$0.0194	\$0.01858	\$0.0380	\$0	0%
GL										
	First 300 kW	\$5,527.00	\$429.56	\$1,546.19	\$3,551.25	\$5,527.00		\$5,527.00	\$0	0%
	Additional kW	\$13.98	\$0.54	\$1.96	\$4.49	\$6.99		\$6.99	\$6.99	50%
	All kWh	\$0.0380	\$0.0015	\$0.0054	\$0.0125	\$0.0195	\$0.01852	\$0.0380	\$0	0%
L										
	First 5,000 kW	\$71,289.00	\$6,797.70	\$21,616.25	\$42,875.05	\$71,289.00		\$71,289.00	\$0	0%
	Next 10,000 kW	\$11.45	\$0.55	\$1.74	\$3.44	\$5.73		\$5.73	\$5.73	50%
	Next 25,000 kW	\$11.13	\$0.53	\$1.69	\$3.35	\$5.57		\$5.57	\$5.57	50%
	Additional kW	\$10.84	\$0.52	\$1.64	\$3.26	\$5.42		\$5.42	\$5.42	50%
	First Block kWh	\$0.0380	\$0.0019	\$0.0059	\$0.0117	\$0.0195	\$0.01847	\$0.0380	\$0	0%
	Next Block kWh	\$0.0256	\$0.0007	\$0.0022	\$0.0043	\$0.0071	\$0.01847	\$0.0256	\$0	0%
	Additional kWh	\$0.0234	\$0.0005	\$0.0015	\$0.0030	\$0.0049	\$0.01847	\$0.0234	\$0	0%
HVPS (4)										
	First 30,000 kW	\$330,536.00	\$37,954.56	\$76,367.59	\$216,213.85	\$330,536.00		\$330,536.00	\$0	0%
	Additional kW	\$11.92	\$1.37	\$2.75	\$7.80	\$11.92		\$11.92	\$0	0%
	On peak kWh	\$0.0448	\$0.0030	\$0.0061	\$0.0172	\$0.0263	\$0.01848	\$0.0448	\$0	0%
	Off peak kWh	\$0.0236	\$0.0006	\$0.0012	\$0.0033	\$0.0051	\$0.01848	\$0.0236	\$0	0%
SE (4)(5)										
	All kWh	\$0.1117	\$0.0030	\$0.0906	\$0.0000	\$0.0936	\$0.01814	\$0.1117	\$0	0%
MTS										
	First 1300 kWh	\$0.1351	\$0.0031	\$0.0074	\$0.0386	\$0.0491	\$0.01842	\$0.0676	\$0.0676	50%
	Additional kWh	\$0.0363	\$0.0011	\$0.0027	\$0.0140	\$0.0179	\$0.01842	\$0.0363	\$0	0%
AL										
	All kW	\$7.02	\$0.30	\$1.88	\$1.33	\$3.51		\$3.51	\$3.51	50%
	First 300 kWh	\$0.1006	\$0.0027	\$0.0172	\$0.0122	\$0.0322	\$0.01814	\$0.0503	\$0.0503	50%
	Additional kWh	\$0.0277	\$0.0008	\$0.0051	\$0.0036	\$0.0096	\$0.01814	\$0.0277	\$0	0%

(1) Does not include customer charges and customer-specific fixed CTCs.

(2) Includes adjustment for STAS roll-in.

(3) Actual CTC charges and customer generation charges/credits will depend on annual market sale of firm power

(4) The ECR roll-in is included in both bundled and unbundled rates. Existing credits are maintained in negotiated HVPS contracts

(5) Rate PAL is based on Rate SE as there were no customers on Rate PAL in 1996

COMPARISON OF CURRENT BUNDLED AND PROPOSED UNBUNDLED REVENUES BY RATE CLASS

Unbundled Rates	1996 Billing Determinants	Unbundled Usage Delivery Revenues					Market Based CGC (1)	Total Unbundled Usage Revenues/ Credits CGC+(T+D+C)	Unbundled Fixed Revenues		Total Unbundled Revenue (3)	Current Bundled Revenues (4)	Difference
		Transmission T	Distribution D	Variable Class-Specific CTC (2) C	Usage Delivery Charges Subtotal (T+D+C)	Distribution Customer Charges			Fixed Customer Specific CTC				
RS	All MWh	2,977,269	\$13,423,406	\$83,565,298	\$21,327,966	\$118,316,670							
	Total MWh	2,977,269	\$13,423,406	\$83,565,298	\$21,327,966	\$118,316,670	\$55,258,113	\$173,574,783	\$37,994,846	\$167,769,123	\$ 379,338,751	\$ 379,338,751	0.000%
RH	Summer/Winter (5)	155,535	\$816,021	\$4,915,686	\$467,933	\$6,199,640							
	Winter (6)	153,666	\$535,182	\$3,223,921	\$306,891	\$4,065,993							
	Total MWh	309,201	\$1,351,203	\$8,139,607	\$774,823	\$10,265,633	\$5,701,667	\$15,967,300	\$1,740,132	\$8,543,913	\$ 26,251,345	\$ 26,251,345	0.000%
RA	Summer/Winter (5)	24,159	\$123,831	\$673,297	\$164,888	\$962,017							
	Winter (6)	9,689	\$32,950	\$179,154	\$43,874	\$259,977							
	Total MWh	33,848	\$156,781	\$852,451	\$208,762	\$1,211,994	\$625,509	\$1,843,503	\$213,832	\$1,343,254	\$ 3,400,589	\$ 3,400,589	0.000%
GS/GM	First 5 kW												
	Additional kW	6,977,437	\$6,508,564	\$31,018,565	\$26,455,969	\$63,983,097							
	First 550 MWh	211,324	\$1,100,841	\$5,246,394	\$4,474,689	\$10,821,924							
	Next 750 MWh	212,613	\$1,012,389	\$4,824,851	\$4,115,152	\$9,952,393							
	Additional MWh	2,197,209	\$4,327,097	\$20,622,113	\$17,588,756	\$42,537,967							
	Total MWh	2,621,146	\$12,948,891	\$61,711,924	\$52,634,567	\$127,295,381	\$48,858,161	\$176,153,543	\$5,592,090	\$96,739,912	\$ 278,485,545	\$ 278,485,545	0.000%
GMH	Summer	First 5 kW											
	Additional kW	288,882	\$311,173	\$1,851,390	\$687,402	\$2,649,965							
	First 550 MWh	6,698	\$40,351	\$214,141	\$89,138	\$343,629							
	Next 750 MWh	6,647	\$36,606	\$194,269	\$80,866	\$311,740							
	Additional MWh	82,118	\$187,552	\$995,337	\$414,315	\$1,597,204							
	Winter	First Block	118,385	\$299,580	\$2,810,475	\$1,169,878	\$4,509,933						
	Additional MWh	118,407	\$265,854	\$1,410,937	\$587,312	\$2,284,113							
	Total MWh	328,256	\$1,371,126	\$7,276,549	\$3,028,910	\$11,676,585	\$6,089,148	\$17,785,734	\$365,376	\$9,431,550	\$ 27,562,660	\$ 27,562,660	0.000%
GLH	Summer	First 300 kW	426	\$282,102	\$863,425	\$1,188,975	\$2,354,502						
	Additional kW	215,770	\$180,707	\$565,899	\$781,626	\$1,508,232							
	All MWh	151,225	\$351,887	\$1,101,900	\$1,483,014	\$2,936,782							
	Winter	First Block	103,575	\$480,504	\$1,504,734	\$2,025,177	\$4,010,416						
	Additional MWh	200,420	\$466,334	\$1,480,380	\$1,965,455	\$3,892,149							
	Total MWh	455,219	\$1,761,514	\$5,516,318	\$7,424,249	\$14,702,081	\$8,457,968	\$23,160,050	\$7,946	\$6,618,853	\$ 29,788,549	\$ 29,788,549	0.000%
GL	First 300 kW	7,688	\$3,293,862	\$11,856,194	\$27,230,980	\$42,381,036							
	Additional kW	4,324,871	\$2,349,547	\$8,457,151	\$19,424,151	\$30,230,848							
	All MWh	2,884,888	\$4,367,689	\$15,721,416	\$36,108,514	\$56,197,618							
	Total MWh	2,884,888	\$10,011,097	\$36,034,761	\$82,763,645	\$128,809,503	\$53,428,126	\$182,237,628	\$22,638,093	\$ 204,875,691	\$ 204,875,691	0.000%	
L	First 5,000 kW	312	\$2,120,882	\$6,744,271	\$13,377,015	\$22,242,168							
	Next 10,000 kW	1,138,342	\$621,423	\$1,976,087	\$3,919,497	\$6,517,008							
	Next 25,000 kW	21,725	\$11,528	\$36,659	\$72,712	\$120,900							
	Additional kW	0	\$0	\$0	\$0	\$0							
	First Block MWh	1,215,883	\$2,264,296	\$7,200,321	\$14,281,573	\$23,746,190							
	Next Block MWh	234,969	\$159,750	\$507,994	\$1,007,588	\$1,675,332							
	Additional MWh	58,822	\$27,558	\$87,632	\$173,816	\$269,006							
	Total MWh	1,509,474	\$5,205,437	\$16,552,965	\$32,832,201	\$54,590,603	\$27,879,985	\$82,470,588	\$2,144,101	\$ 84,614,689	\$ 84,614,689	0.000%	
HVPS (7)	First 30,000 kW	36	\$1,386,364	\$2,749,233	\$7,783,898	\$11,899,296							
	Additional kW	690,166	\$944,659	\$1,900,729	\$5,381,391	\$8,226,779							
	On peak MWh	315,165	\$952,436	\$1,916,377	\$5,425,695	\$8,294,509							
	Off peak MWh	886,659	\$521,077	\$1,048,449	\$2,968,396	\$4,537,921							
	Total MWh	1,201,824	\$3,784,537	\$7,614,788	\$21,559,180	\$32,958,505	\$22,209,708	\$55,168,213	\$0	\$ 55,168,213	\$ 55,168,212	0.000%	
SE (7)	All MWh	28,818	\$84,927	\$2,592,501	\$0	\$2,677,428	\$519,128	\$3,196,556	\$0	\$ 3,196,557	\$ 3,196,557	0.000%	
MTS	First 1300 MWh	10,665	\$33,470	\$78,998	\$411,508	\$523,976							
	Additional MWh	974	\$1,112	\$2,628	\$13,678	\$17,416							
	Total MWh	11,639	\$34,582	\$81,624	\$425,186	\$541,392	\$214,393	\$755,785	\$180,160	\$696,780	\$ 1,632,725	\$ 1,632,725	0.000%
AL	All kW	68	\$20	\$128	\$91	\$239							
	First 300 MWh	4	\$11	\$72	\$51	\$135							
	Additional MWh	9	\$7	\$46	\$33	\$86							
	Total MWh	13	\$39	\$247	\$175	\$461	\$240	\$701	\$163	\$478	\$ 1,342	\$ 1,342	0.000%
Total - Unbundled		12,361,395	\$50,320,543	\$236,879,787	\$222,979,663	\$503,052,235	\$229,242,146	\$732,294,382	\$46,094,246	\$315,926,027	\$1,094,314,655	\$1,094,314,655	0.000%
Bundled Rates													
	SM	31,448	\$184,011	\$6,886,302							\$12,305,786	\$12,305,786	
	SH	837	\$2,992	\$54,453							\$167,041	\$167,041	
	Total - Bundled	32,285	\$187,003	\$6,940,755							\$12,472,827	\$12,472,827	
TOTAL		12,393,680	\$50,507,546	\$243,820,542	\$222,979,663	\$503,052,235	\$229,242,146	\$732,294,382	\$46,094,246	\$315,926,027	\$1,106,787,482	\$1,106,787,482	0.000%

(1) Actual CTC charges and customer generation charges/credits will depend on annual market sale of firm power.
(2) Based on 1996 billing determinants and roll-in of ECR and STAS credits.
(3) Rates SM and SH were not unbundled and shown for information.
(4) Based on actual 1996 revenues adjusted for roll-in of ECR at cap.
(5) Winter mWh at 1st block.
(6) Winter mWh at 2nd block.
(7) The ECR roll-in is included in both bundled and unbundled rates. Existing credits are maintained in negotiated HVPS contracts.

RETAIL MARKET PRICES OFFERED TO RESIDENTIAL CUSTOMERS
(Massachusetts Electric Retail Access Pilot)

<u>Supplier By Price Option</u>	<u>Market Share</u> (kWh)	<u>%</u>	<u>Retail Prices [4]</u> (\$/mWh)
<i>Price Options: [1]</i>			
Enova	13,162,824	44%	19.3
Northeast Utilities	7,313,256	24%	22.9
WEPCO	885,684	3%	27.1
<i>Green Options: [2]</i>			
AllEnergy	335,448	1%	34.1 [5]
Enova	820,140	3%	22.1
Northfield Mountain	2,812,548	9%	20.0
Working Assets	3,650,364	12%	29.8
<i>Other Options: [3]</i>			
AllEnergy	844,272	3%	28.7
WEPCO	<u>54,732</u>	<u>0%</u>	<u>Variable [6]</u>
Total	29,879,268	100%	22.2

Notes:

- [1] These options aim to offer the lowest price for electricity.
- [2] These options aim to be environmental, either in their generation source or through projects they support.
- [3] These options offer donations and a variable pricing alternative.
- [4] The comparative prices shown reflect the base price and any bonuses offered by the suppliers.
- [5] Price options range from \$30.1 to \$34.1 per mwh; the highest figure was used for purposes of this analysis.
- [6] Power Markets Week NEPOOL Weekly Index + \$1 per mWh.

Source: Environmental Futures, Inc.

WHOLESALE ELECTRICITY PRICES IN NEPOOL

1996 Week Ending	On-Peak Index Price (\$/mWh) NEPOOL	Off-Peak Average Price (\$/mWh) NEPOOL
01/12/96	32.00	24.00
01/19/96	32.00	23.00
01/26/96	29.00	21.50
02/02/96	30.75	21.00
02/09/96	35.75	21.00
02/16/96	31.75	22.00
02/23/96	28.50	20.00
03/01/96	26.00	20.00
03/08/96	29.50	19.50
03/15/96	27.00	22.50
03/22/96	26.75	20.00
03/29/96	27.00	19.50
04/05/96	26.00	17.50
04/12/96	26.00	16.50
04/19/96	25.75	18.50
04/26/96	24.50	19.00
05/03/96	25.00	18.00
05/10/96	24.30	16.50
05/17/96	23.45	17.38
05/24/96	27.85	20.50
05/31/96	23.75	18.00
06/07/96	23.25	16.25
06/14/96	25.25	17.50
06/21/96	25.80	18.50
06/28/96	25.70	17.00
07/05/96	25.12	18.00
07/12/96	26.45	17.50
07/19/96	28.90	18.00
07/26/96	28.50	18.00
08/02/96	27.30	19.00
08/09/96	35.27	20.50
08/16/96	25.99	17.25
08/23/96	27.64	18.00
08/30/96	25.85	17.50
09/06/96	26.88	17.50
09/13/96	29.59	20.00
09/20/96	27.65	20.00
09/27/96	27.80	18.50
10/04/96	27.95	20.50
10/11/96	30.12	20.00
10/18/96	32.45	21.75
10/25/96	34.00	20.88
11/01/96	34.00	20.25
11/08/96	34.48	21.50
11/15/96	35.00	19.75
11/22/96	33.70	22.50
11/29/96	33.69	22.13
12/06/96	34.70	22.25
12/13/96	35.00	20.00
12/20/96	34.60	22.50
12/27/96	33.31	23.00
01/03/97	30.81	22.00
Average Price	29.03	19.69

1996 Weighted Average Price:

	\$/MWH	Hours	
On-Peak	29.03	4,160	47.5%
Off-Peak	19.69	4,600	52.5%
Hourly Wtd. Average	\$24.12	8,760	100.0%

Notes: Indexes are based on prices of actual transactions obtained in confidential surveys of buyers and sellers. The weekly on-peak indexes represent an average daily price for the preceding week, Monday through Friday. On-peak hours are 6 a.m. to 10 p.m. (16 hours) five days a week. Each weekday is given equal weight to determine the weekly index price. The index prices are an assessment of where the bulk of dealmaking occurred. The chief determinant of the index price is the volume-weighted average. However, the straight average, median and mode also are considered. Off-peak prices are the average of the reported high and low price range for the week during off-peak periods.

SAMPLE CUSTOMER GENERATION CHARGES/CREDITS (CGC) BASED ON RECENT RFP _1/

One-Year Market Price From Recent RFP Contract (at 75% load factor) **18.16**
 Associated One-Year Market Price (at 100% load factor) _2/ **17.45 [A]**

Rate Class	\$/MWH			
	[B] Customer Class Load Pattern Adjustment _3/	[C] Customer Generation Charge/Credit (Without T Losses and GRT)	[D] Customer Generation Charge/Credit (Incl. T Losses, without GRT)	[E] Customer Generation Charge/Credit (Incl. T Losses and GRT.)
RS	1.0079	17.59	17.75	18.56
RA	1.0033	17.51	17.67	18.48
RH	1.0011	17.47	17.63	18.44
GS/GM	1.0118	17.66	17.82	18.64
GMH	1.0071	17.57	17.73	18.55
GLH	1.0089	17.60	17.76	18.58
GL	1.0057	17.55	17.71	18.52
L	1.0030	17.50	17.66	18.47
HVPS	1.0036	17.51	17.67	18.48
SE	0.9851	17.19	17.34	18.14
MTS	1.0000	17.45	17.61	18.42
AL	0.9848	17.18	17.34	18.14
PAL	0.9848	17.18	17.34	18.14

NOTES:

Final credits are rounded to two decimals; interim calculations carry more decimal places.

[C] = [A] * [B]

[D] = [C]/(1-.009)

[E] = [D]/(1-.044)

_1/ Actual customer credits will depend on the results of a competitive market solicitation conducted each year. Customer credits will be determined based on the highest winning bids for firm power. Credits are adjusted for customer class load patterns, transmission losses, and related gross receipts taxes.

_2/ The 100% load factor market price was derived from the 75% load factor RFP price based on Company actual 1996 system lambda price data in all the hours of the year. This price shape will be updated each year to reflect the latest known and measurable price information.

_3/ The customer class load pattern adjustment is determined by weighting hourly prices by the customer class load pattern. These load patterns are based on historical 1996 TOU data for a sample of residential, commercial, and industrial customers.

ELECTRIC DELIVERY - PA. P.U.C. NO. 1

DUQUESNE LIGHT COMPANY
SCHEDULE OF RATES

For Electric Service in Allegheny and Beaver Counties

(For List of Communities Served, see Page No. 4)

Issued By

DUQUESNE LIGHT COMPANY

411 Seventh Avenue
Pittsburgh, PA 15219

DAVID D. MARSHALL

President and Chief Executive Officer

ISSUED: July 31, 1997

EFFECTIVE: January 1, 1999

NOTICE

THIS TARIFF MAKES CHANGES TO EXISTING RATES AND RIDERS - See Page Two

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

The changes in this tariff to the following rates and riders reflect the unbundling of rates required by Section 2806(E) of Act 138 of 1996:

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LIST OF COMMUNITIES SERVED

The Company renders service in portions of Allegheny and Beaver Counties, Pennsylvania. Electric service is available in all localities where the Company has distribution facilities, including all or a portion of the following cities, boroughs and townships.

ALLEGHENY COUNTY

Cities and Boroughs

Aspinwall	Dormont	Jefferson	Roslyn Farms
Avalon	Dravosburg	Leetsdale	Sewickley
Baldwin	Duquesne	Liberty	Sewickley Heights
Bell Acres	East McKeesport	Lincoln	Sewickley Hills
Bellevue	East Pittsburgh	McKeesport	Sharpsburg
Ben Avon	Edgewood	McKees Rocks	Swissvale
Ben Avon Heights	Edgeworth	Millvale	Thornburg
Bethel Park	Emsworth	Monroeville	Trafford
Blawnox	Etna	Mt. Oliver	Turtle Creek
Braddock	Forest Hills	Munhall	Verona
Braddock Hills	Fox Chapel	North Braddock	Versailles
Brentwood	Franklin Park	Oakmont	Wall
Carnegie	Glassport	Osborne	West Homestead
Castle Shannon	Glenfield	Pennsbury Village	West Mifflin
Chalfant	Green Tree	Pittsburgh	West View
Churchill	Haysville	Pleasant Hills	Whitaker
Clairton	Heidleberg	Plum	Whitehall
Coraopolis	Homestead	Port Vue	White Oak
Crafton	Ingram	Rankin	Wilkesburg
			Wilmerding

Townships

Aleppo	Kilbuck	Ohio	Shaler
Baldwin	Leet	Penn Hills	Stowe
Collier	McCandless	Pine	Upper St. Clair
Crescent	Moon	Reserve	West Deer
Findlay	Mt. Lebanon	Richland	Wilkins
Hampton	Neville	Robinson	
Indiana	North Versailles	Ross	
Kennedy	O'Hara	Scott	

LIST OF COMMUNITIES SERVED - (Continued)

BEAVER COUNTY

Cities and Boroughs

Aliquippa	East Rochester	Glasgow	Patterson Heights
Ambridge	Eastvale	Hookstown	Rochester
Baden	Economy	Industry	Shippingport
Beaver	Fallston	Midland	South Heights
Beaver Falls	Frankfort Springs	Monaca	West Mayfield
Bridgewater	Freedom	New Brighton	
Conway	Georgetown	Ohioville	

Townships

Brighton	Hanover	New Sewickley	Raccoon
Center	Harmony	Patterson	Rochester
Daugherty	Hopewell	Potter	Vanport
Greene	Independence	Pulaski	White

RULES AND REGULATIONS

THE ELECTRIC SERVICE TARIFF

1. **FILING AND POSTING** A copy of the tariff, comprising the Rates, Riders, and Rules and Regulations governing the supply of electric service, is filed with the Pennsylvania Public Utility Commission and is posted and open to inspection at the offices of the Company where payments are made by customers.
2. **REVISIONS** The tariff is subject to such change and modification as may be made from time to time in the manner prescribed by the Public Utility Law. If any rate for electric delivery service is increased, the affected customer shall have the option of discontinuing service, but shall be obligated to pay the increased rate from the effective date thereof until service has been discontinued.
3. **APPLICATION** Rates of the tariff apply only to the Company's Standard Service delivered from overhead supply lines except in certain restricted areas where the Company is required to provide underground distribution. Riders of the tariff amend or modify the terms governing the delivery service under the rates to which they apply. Standard Service is alternating current of sixty cycles frequency, conforming as to voltage and phase with the following list of standard nominal service delivery voltages.

<u>SINGLE-PHASE</u>	<u>THREE-PHASE</u>	
120 volts, 2 wire	120/208 volts, 4 wire	11,500 volts, 3 wire
120/240 volts, 3 wire	230 volts, 3 wire	13,200/23,000 volts, 4 wire
120/208 volts, 3 wire	277/480 volts, 4 wire	23,000 volts, 3 wire
230 volts, 2 wire	460 volts, 3 wire	69,000 volts, 3 wire
460 volts, 2 wire	2,400 volts, 3 wire	138,000 volts, 3 wire
230/460 volts, 3 wire	2,400/4,160 volts, 4 wire	345,000 volts, 3 wire
2,400 volts, 2 wire		
23,000 volts, 2 wire		

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS

4. **CONTRACTS** The Company reserves the right to require the customer to sign a written contract indicating the rate under which electricity is to be delivered and to require a contract term which, in the judgment of the Company, is sufficient to justify the cost of any facilities installed for the exclusive use of the customer. Receipt of electric service, however, shall constitute the receiver a customer of the Company, subject to its rules and regulation, whether service is based upon contract, agreement, accepted signed application or otherwise. The customer shall notify the Company, in advance of receipt of service, of the customer's name, address to which the electricity is to be delivered, the address to which the bill is to be mailed, the date delivery of electricity is to commence, and supply information requested by the Company regarding the customer's credit standing. The customer shall notify the Company to cancel delivery of electricity and the customer shall be responsible for payment for all delivery charges until the customer has so notified the Company to cancel delivery of energy.

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

4. CONTRACTS - (Continued)

The Company at its sole discretion may enter into special contracts for delivery of and/or the purchase of electricity with industrial customers having load of at least 100 kW to address changing business needs or operating conditions, or for incremental sales of at least 100 kW from existing or new industrial customers.

The Company at its sole discretion may enter into special contracts for delivery of and/or the purchase of electricity with industrial or commercial customers having load of at least 100 kW to address less expensive competitive alternatives for energy to be used for applications other than space heating. If requested by the Company, the customer shall provide to the Company, on a confidential basis, all information, records and financial analysis necessary to evaluate the customer's request for a special contract.

Terms and conditions of service will be mutually agreed upon by the Company and the customer and included in a signed contract, which will be filed with the Public Utility Commission. The Company at its sole discretion may request Public Utility Commission approval. The terms of the agreement will be confidential upon filing with the Commission. Rates established under special contracts will be sufficient to recover, at a minimum, all appropriate incremental costs and a contribution to fixed costs.

The contract shall contain all service terms and conditions and the rates and charges to be paid for the delivery of and/or the purchased electricity. The contract shall be for a period of no less than five years and no greater than ten years.

The contract will be terminated by the Company if the Company charges are not paid when due as specified in Tariff Rule No. 21, before the addition of the Late Payment Charge. Upon termination of the contract under these conditions, the regular electricity delivery rates will be applied to service rendered from that point forward. The fixed competitive transition charge (CTC) as discussed in the applicable customer rate will be based upon the 1 Year Option for the contract period. The Company energy charges will be based on the 1 Year Option charge unless the customer has made arrangements for electricity from another supplier. A new special contract will not be made available to a customer whose previous special contract was terminated because of failure to pay bills as specified in Tariff Rule No. 21.

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

5. **DEPOSITS AND ADVANCE PAYMENTS** The Company reserves the right to require a cash deposit from applicants taking service for a period of less than thirty days, in an amount equal to the estimated gross bill for such temporary service. The gross bill shall include all fixed charges and capacity and energy charges per the applicable tariff and electricity energy charges per the 1 Year option. Deposits may be required from all other applicants when credit has not been established or from existing ratepayers when such ratepayer's credit standing is impaired by delinquent payments of any two consecutive electric delivery bills or three or more bills within the preceding 12 months or as a condition to the reconnection of service or by failure to comply with a settlement or amortization agreement. The amount of the deposit will not exceed the estimated gross bill for two months for applicants and the average actual bill for two months for existing ratepayers. Deposits secured from a residential applicant or ratepayer shall be returned to the depositor when he shall have paid undisputed bills for service over a period of 12 consecutive months without having service terminated and without having paid his bill subsequent to the due date on more than two occasions as long as the ratepayer is not currently delinquent. Deposits secured from other than residential customers shall be returned to the depositor upon annual review provided such depositor shall have paid undisputed bills during those consecutive 12 months without having service terminated and without having paid his bill subsequent to the due date so long as the ratepayer is not currently delinquent. The payment of any undisputed bill shall be payment of the bill within thirty days following presentation of the bill, or the payment of any contested bill, payment of which is withheld beyond the period herein mentioned and the dispute is terminated substantially in favor of the ratepayer and payment made by the ratepayer within 15 days thereafter. The Company will pay interest on residential cash deposits at the rate of the average of 1-year Treasury Bills for September, October and November of the previous year beginning May 1, 1995 and January 1, 1996 and each year thereafter, without deduction for any taxes thereon. For all other cash deposits, the Company will pay interest at the rate of six percent per annum without deduction for any taxes thereon. On deposits held for more than one year, accrued interest will be paid at the end of each anniversary year. Upon the return of a deposit, any unpaid interest accrued thereon will be paid. Where service is discontinued, the deposit and unpaid interest accrued thereon to the date of discontinuance of service, less the amount of all bills due the Company, will promptly be paid to the ratepayer. The Company reserves the right to require payment in advance for seasonal service, when the applicants elect to take such service, in an amount equal to the estimated gross charges for such seasonal service as determined by the provisions of the rate under which this service is taken.

INSTALLATION OF SERVICE

6. **INSTALLATION RULES** Service installations shall be made in accordance with the Company's "Electric Service Installation Rules," copies of which may be obtained at the Company's offices.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS

A. Definitions

For the purposes of this rule, the following definitions are applicable:

- (1) **Contractor cost** - The amount paid to a contractor for work performed on a line extension.
- (2) **Direct labor cost** - The pay and expenses of public utility employees directly attributable to work performed on line extensions, but does not include construction overheads or payroll taxes, workers' compensation expenses, or similar expenses.
- (3) **Direct material cost** - The purchase price of materials used for a line extension, but does not include the related stores expenses. In computing direct material costs, proper allowance should be made for unused materials recovered from temporary structures, and discounts allowed and realized in the purchase of materials.
- (4) **Total construction cost** - The contractor cost, direct labor cost, direct material cost, stores expense, construction overheads, payroll taxes, workers' compensation expenses, or similar expenses.
- (5) **Current Year** - For purposes of calculating a revenue guarantee, current year shall be each consecutive period of 12 calendar months following the date permanent electric delivery service was first provided to a customer.
- (6) **Income Tax** - Federal and State tax relating to the tax liability of contributions in aid-of-construction.

B. Overhead Areas

- (1) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all single-phase overhead supply lines operating at 23,000 volts or less to the customer's property line without a guarantee of revenue.
- (2) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all three-phase overhead supply lines, operating at 23,000 volts or less, which are usable as a part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer over a period of five years or less which is sufficient to recover the actual total construction cost of the three-phase overhead line extension, less the estimated total construction cost for an equivalent single-phase overhead line extension. Any additional revenue payment required will include the related income tax.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

B. Overhead Areas - (Continued)

- (3) When the customer has a severe fluctuating or unbalanced load, or requests an alternate routing or a deviation from the Company's standard overhead construction practices, the additional cost incurred plus the related income tax will be borne by the customer and will not be included when determining the revenue guarantee amount.

C. Underground Areas

- (1) In areas where the existing supply lines are underground outside the limits of a residential development covered by Tariff Rule 13.2, the Company will construct and maintain extensions of all single-phase underground supply lines operating at 23,000 volts or less which are usable as part of its general supply system without a guarantee of revenue. When the single-phase supply line extension is to supply electricity exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer, over a period of three years or less which is sufficient to recover the actual total contractor cost, direct labor cost and direct material cost for the full length of the single-phase underground line extension, less the estimated total contractor cost, direct labor cost, and direct material cost for an equivalent single-phase overhead line extension.
- (2) In areas where the existing supply lines are underground outside of the limits of a residential development covered by Tariff Rule 13.2, the Company will construct and maintain extensions of all three-phase underground supply lines operating at 23,000 volts or less which are usable as part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer over a period of three years or less which is sufficient to recover the actual total construction cost of the three-phase underground line extension, less the estimated total construction cost for an equivalent single-phase overhead line extension. Any additional revenue payment required will include the related income tax.
- (3) When the customer has a severe fluctuating or unbalanced load, or requests an alternate routing or a deviation from the Company's standard underground construction practices, the additional cost plus the related income tax will be borne by the customer and will not be included when determining the revenue guarantee amount.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

D. Rights-of-Way

Before construction of a line extension, satisfactory rights of way and other necessary permits must be granted to the Company for the construction of the supply line extension along the route selected by the Company. The customer agrees to pay the Company any initial and recurring rights-of-way or license fees in excess of an amount normally incurred by the Company in constructing and maintaining the supply line extension.

E. Revenue Guarantees

The revenue guarantee amount shall be the actual cost of the line extension. The annual revenue guarantee amount shall be the revenue guarantee amount, divided by the number of years in the guarantee period.

The annual revenue guarantee amount will be reviewed yearly and will be adjusted to the minimum charges as provided in the applicable rate schedule on the following basis:

- (1) When the total of the monthly electricity delivery bills, including any Company supplied energy at the end of the current year are less than the annual revenue guarantee amount, a payment equal to the difference plus the related income tax where applicable shall be immediately due and payable.
- (2) When the total of the monthly electricity delivery bills, including any Company supplied energy within the number of years in the guarantee period, equals or exceeds the revenue guarantee amount, no further payments are required. Any prior payments in excess of the revenue guarantee amount will be refunded with accrued interest.
- (3) If an additional customer is served from the line extension, the revenue guarantee amount will be reduced to the cost of the line extension which is used exclusively to serve the single customer. If the cost of the line extension to serve the new customer would increase the revenue guarantee amount for an existing customer, the extension shall be considered as a new line extension.
- (4) In the event the customer discontinues or cancels service before the end of the guarantee period, the balance of the revenue guarantee amount plus the related income tax where applicable shall be immediately due and payable.

8. CONNECTION CHARGES The Company reserves the right to make a reasonable charge including the related income tax, payable in advance, for service lines and for equipment installed for the exclusive use of a customer which exceed Company established standards described in the Company's "Electric Service Installation Rules."

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

9. RELOCATIONS OF FACILITIES

A. Pole Removal or Relocation for Residential Customers

When requested by a residential property owner who is not otherwise entitled to receive condemnation damages to cover the cost of the pole removal or relocation or who is not requesting a pole removal or relocation as the result of damages caused by the intentional or negligent conduct of any party, the Company will when it is practicable, subject to the execution and receipt of required easements, licenses or municipal permits, remove or relocate a pole or poles and associated attachments, upon receipt, in advance, of the Company's estimated contractor or direct labor and direct material costs associated with the particular pole removal or relocation, less any maintenance expenses avoided as a result of the pole removal or relocation.

For purposes of this Rule, the following definitions are applicable:

- (1) **Contractor costs** - Amount paid by the utility to a contractor for work performed on a pole removal or relocation.
- (2) **Direct labor costs** - Includes pay and expenses of public utility employees directly attributable to work performed on pole removals or relocations. Excludes payroll taxes, workmen's compensation, similar items of expense and construction overhead costs.
- (3) **Direct materials costs** - Includes the purchase price of materials used in performing a pole removal or relocation and excludes the related stores expenses. Proper allowance shall be made for unused materials, and materials recovered from temporary structures, and for discounts allowed and realized in purchase of materials.
- (4) **Income tax** - Federal and State tax relating to the tax liability of contributions in aid-of-construction.

B. Other Company Facilities for all Customers

When requested or required by the action of a customer or a third party, relocation of Company facilities, except those covered under Section A of this Rule, will be performed by the Company upon receipt, in advance, of the Company's estimated total direct and indirect costs including the related income tax of such relocations from the customer or such third party. The Company may waive charges under this rule if, in the Company's judgment, the location of the Company's existing supply line and/or service line on the customer's property restricts the growth of the customer's operations and the potential increase in the Company's revenues.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

10. ONE SERVICE OF A KIND Only one service of each type as to voltage and phase will be supplied to a customer under one contract; provided, however, that when, in the judgment of the Company, compliance with Rule No. 17, Fluctuations and Unbalances, may be most economically effected by establishing a separate service connection for a portion of the customer's load, such separate service connection may, at the option of the customer, be combined, notwithstanding similarity as to voltage and phase, with other service connections under a single contract for the customer's entire electric delivery service requirements at the affected location. Delivery service at different premises, regardless of voltage or phase, shall never be combined for billing under one account.

11. METER SUPPORTS The customer shall provide on the premises, at a location satisfactory to the Company, proper space, supports, and enclosures for metering equipment.

12. TRANSFORMERS AND CONTROL EQUIPMENT Where, in the judgement of the Company, it is necessary to install transformers and other control or protective equipment on the customer's premises, the customer shall provide a suitable place, foundation and housing for such installation, in accordance with the Company's "Electric Service Installation Rules."

13. CUSTOMER'S FACILITIES The installation and maintenance of the customer's wiring and equipment shall be in accordance with the Company's "Electric Service Installation Rules" and shall be subject to the approval of the proper authorities. The Company is not required to deliver electricity thereto unless so approved, but does not assume any responsibility for securing such approval. The Company shall not be liable for damages or injuries resulting from any defects in the customer's wiring or equipment.

13.1 UNDERGROUND DISTRIBUTION

A. When the Company is required by governmental order or enters into agreements with redevelopment authorities, a private real estate developer or a group of customers to change its distribution supply lines from overhead to underground, customers receiving or to receive electric service at voltages of 600 volts or less from these supply lines shall provide at their own expense the necessary facilities for receiving such underground service.

B. Underground Service Lines from Overhead Supply Lines

(1) Service Line Voltages Under 600 Volts.

(a) Where an underground service line is installed from the Company's overhead, street secondary supply lines, the customer shall furnish and install all conductors and conduit in accordance with the Company's "Electric Service Installation Rules."

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

13.1 UNDERGROUND DISTRIBUTION - (Continued)

B. Underground Service Lines from Overhead Supply Lines - (Continued)

(2) Service Line Voltages Over 600 Volts.

- (a) Where the Company's supply lines are overhead, the customer shall furnish and install all conduits or ducts for the underground primary service line within the street area as well as all necessary conduit, ducts, manholes and junction boxes on private property in accordance with the Company's "Electric Service Installation Rules."

13.2 UNDERGROUND ELECTRIC SERVICE IN NEW RESIDENTIAL DEVELOPMENTS

A. Definitions

The following words and terms, when used in this rule shall have the following meanings, unless the text clearly indicates otherwise.

- (1) **Applicant for Electric Service** - The developer of a recorded plot plan consisting of five or more lots, or of one or more five-unit apartment houses.
- (2) **Developer** - The party responsible for constructing and providing improvements in a development, that is, streets, sidewalks, and utility-ready lots.
- (3) **Development** - A planned project which is developed by a developer/applicant for electric service set out in a recorded plot plan of five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, or mobile homes and one or more five-unit apartment houses, all of which are intended for year-round occupancy, if providing electric delivery service to such project necessitates extending the Company's existing distribution lines.
- (4) **Distribution line** - An electric supply line of untransformed voltage which delivers energy to one or more service lines.
- (5) **Service line** - An electric supply line of transformed voltage which delivers service to a residence or building as described in the Company's Construction Standards.
- (6) **Subdivider** - The party responsible for dividing a tract of land into building lots which are not to be sold as utility-ready lots.
- (7) **Subdivision** - A tract of land divided by a subdivider into five or more adjoining unoccupied lots for the construction of single-family residences, detached or otherwise, or one or more five-unit apartment houses, all of which are intended for year-round occupancy, if providing electric delivery service to such subdivision necessitates extending the Company's existing distribution lines.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

13.2 UNDERGROUND ELECTRIC SERVICE IN NEW RESIDENTIAL DEVELOPMENTS - (Continued)

B. Installation of Distribution and Service Lines

Distribution and service lines installed under an application for electric service within a development will be installed underground; will conform to the Company's construction standards, the Pennsylvania PUC regulation 57.26 of Title 52 (relating to construction and maintenance of facilities), the specifications set forth in the National Electric Safety Code (NESC), and will be owned and maintained by the Company. Pad-mounted transformers will be installed as a Company construction standard. Excavating and backfilling shall be performed by the developer of the project or by another agent as the developer may authorize. Installation of service-related Company facilities will be performed by the Company or by another agent as the Company may authorize. Street-lighting lines installed then or thereafter within the same development will also be installed underground, upon terms and conditions prescribed elsewhere in the Company's tariff. The Company will not be liable for injury or damage occasioned by the willful or negligent excavation, breakage, or other interference with its underground lines occasioned by anyone other than its own employees or agents.

Nothing in this rule shall prohibit the Company from performing its own excavating and backfilling for greater system design flexibility. However, no charges to the developer other than those specified in C(4) of this rule will be charged.

C. Applicants for Electric Service

The applicant for electric service to a development shall conform with the following:

- (1) At its own cost, provide the Company with a copy of the recorded development plot plan identifying property boundaries, and with easements satisfactory to the Company for occupancy by distribution, service and street-lighting lines and related facilities.
- (2) At its own cost, clear the ground in which the lines and related facilities are to be laid of trees, stumps and other obstructions, provide the excavating and backfilling subject to the inspection and approval of the Company, and rough grade it to within six inches of final grade, so that the Company's part of the installation shall consist only of laying of the lines and installing other service-related facilities. Excavating and backfilling performed or provided by the applicant will follow the Company's underground construction standards and specifications set forth by the Company in written form and presented to the applicant at the time of application for service and presentation of the recorded plot plan to the Company. If the Company's specifications have not been met by the applicant's excavating and backfilling, the excavating and backfilling will be corrected or redone by the applicant or its authorized agent. Failure to comply with the Company's construction standards and specifications permits the Company to refuse utility service until the standards and specifications are met.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

13.2 UNDERGROUND ELECTRIC SERVICE IN NEW RESIDENTIAL DEVELOPMENTS - (Continued)

C. Applicants for Electric Service - (Continued)

- (3) Request electric delivery service at such time that the lines may be installed before curbs, pavements and sidewalks are laid; carefully coordinate scheduling of the Company's line and facility installation with the general project construction schedule, including coordination with other utilities sharing the same trench; keep the route of lines clear of machinery and other obstructions when the line installation crew is scheduled to appear; and otherwise cooperate with the Company to avoid unnecessary costs and delay.
- (4) Pay to the Company any necessary and additional costs incurred by the Company as a result of the following:
 - (a) Installation of underground facilities that deviate from the Company's underground construction standards and specifications if such deviation is requested by the applicant for electric delivery service and is acceptable to the Company.
 - (b) A change in the plot plan or final grade elevations by the applicant for electric delivery service after the Company has completed engineering for the project and/or has commenced installation of its facilities.
 - (c) Physical characteristics such as oversized lots or lots with extreme set-back where under the Company's line extension policy contained in its tariff a charge is mandated for overhead delivery service.
- (5) No charges other than those described in paragraph (4) of this rule shall be borne by the applicant for electric delivery service or by any other utility sharing the same trench, even if the Company elects to perform its own excavating and backfilling.
- (6) No charges other than those described in paragraphs (4) or (5) will be borne by the applicant, even if the Company elects to perform its own trenching and backfilling.

D. Installing Distribution Lines Beyond Boundary of Development

Whenever the distance from the end of the Company's existing distribution line to the boundary of the development is 100 feet or more, the 100 feet of new distribution line nearest to but outside such boundary shall be installed underground if practicable; and whenever such distance is less than 100 feet from said boundary, all of the new distribution line nearest to but outside such boundary shall be installed underground if practicable. The installation required by this paragraph shall be provided by the Company, without cost to the applicant. However, the developer must provide the excavating and backfilling.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

13.2 UNDERGROUND ELECTRIC SERVICE IN NEW RESIDENTIAL DEVELOPMENTS - (Continued)

E. Classification of Charges

Amounts the Company receives under paragraph C(4) (relating to applicant for electric service) will be credited to Contributions in Aid of Construction.

F. Exceptions

(1) Whenever the Company or any affected person believes that the application of the tariff rule works an undue hardship, involves a physical impossibility, or is otherwise inappropriate, the Company or persons may request an exception from the underground requirements of paragraphs A through E of this rule (relating to definitions, installation of distribution and service lines, applicant for electric delivery service, installing distribution lines beyond boundary of development, and calculation and classification of charges) by providing the Pennsylvania Public Utility Commission with the following:

(a) A copy of the recorded plot plan of the development for which the exception is being sought.

(b) A letter petition setting forth:

(i) the name of the applicant

(ii) the location and size of the development involved

(iii) the names of the electric utility and telephone utility which will provide service to that development

(iv) the date on which construction began or will begin; whether the development is a new development or one phase in a development to be completed in several phases; and whether facilities in the area surrounding the development have been installed underground or overhead.

(2) Upon the filing of an exception request, the Pennsylvania Public Utility Commission (Commission) Staff will notify the utilities involved and the appropriate local government authority, review the facts stated in the request, and issue to the applicant and the utility an informal written report and decision within 180 days of the request for an exception. Failure of the party requesting an exception to supply sufficient data within 180 days of the period shall result in the automatic denial of the request.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

13.2 UNDERGROUND ELECTRIC SERVICE IN NEW RESIDENTIAL DEVELOPMENTS - (Continued)

F. Exceptions - (Continued)

- (3) A public utility or any affected person may appeal the informal decision rendered by Commission Staff by filing a letter petition with the Secretary of the Commission stating the facts in question and requesting a hearing. All appeals shall be referred to the Commission's Office of Administrative Law Judge for hearing and decision.
- (4) If an exception request initiated by an applicant for electric delivery service is granted, and the applicant thereafter desires underground electric delivery service, then paragraphs B and C (relating to installation of distribution and service lines and applicant for electric service) will apply as if no exception had been granted.

G. Applicability

This rule shall apply to applications for service to developments, which are filed with the Company after June 30, 1984.

H. Subdivisions

Underground facilities in new residential developments are only required by paragraphs A through G (relating to underground electrical service in new residential developments) when a bona fide developer exists, that is, only when utility-ready lots are provided by the developer. A mere subdivision is not required to have underground service. Should the lot owner or owners in a subdivision desire underground service, the service will be provided by the Company if the lot owner or owners, at their option, either comply with paragraph C (relating to applicants for electric service) or pays to the Company charges that are contained in the Company's tariff for underground electric service not required by this rule.

13.3 BUILDING ENERGY CONSERVATION STANDARDS FOR RECEIPT OF UTILITY SERVICE FOR RESIDENTIAL BUILDINGS Pursuant to the requirements of amended Pa. Code §69.101 through §69.107, the following provisions are incorporated in this Tariff:

The Company must receive proof of compliance with, or exemption from, the insulation standards set forth in the Building Energy Conservation Act (Act 222) prior to delivery of electricity for any purpose, including temporary electric service for residential building construction purposes, to (1) new residential buildings, (2) additions to existing residential buildings, and (3) renovated residential buildings located in municipalities that have not elected to administer Act 222.

Proof of compliance shall be made by furnishing the Company with a "Notice of Intent to Construct" form certified by Pennsylvania's Department of Community Affairs.

Upon request, the Company will provide information and the required forms for compliance with Act 222.

RULES AND REGULATIONS - (Continued)

MEASUREMENT AND USE OF SERVICE

14. MEASUREMENT OF SERVICE The quantity of energy recorded by the Company's meters shall be final and conclusive, except where the meters fail to register or are determined to be in error; in these instances, the quantity delivered during the period in question shall be estimated, after due consideration of previous or subsequent properly measured deliveries. Tests of meters made upon written request of the customer will be in accordance with the rules and regulations of the Pennsylvania Public Utility Commission. See Rule 42 for more detail on meter inspections. For customers who desire to have additional metering installed for purchasing electricity from another electricity supplier, the cost for installing such metering will be the responsibility of the customer or the alternate energy supplier. The installer of such metering must comply with Company rules as applicable for the installation.

14.1 METER READING INTERVALS The Company will read its meters at scheduled monthly intervals.

14.2 BILLING The Company will render a bill monthly for the delivery of electricity. Customers eligible to choose an electric energy supplier will have the option of integrated billing or separate billing. For integrated billing, the customer will receive one integrated bill for Company delivery and electric energy charges regardless of the electric energy supplier. For customers choosing separate billing, the customer will receive a bill from the Company for delivery charges and a bill from the electric energy supplier for electric energy charges. The customer must notify the Company of the billing arrangement at the time the electric energy supplier is chosen. All rules and regulations of this tariff as well as billing options apply to both options regardless of the electric energy supplier.

15. INABILITY TO READ RESIDENTIAL METERS When scheduled readings of kilowatt-hour meters are not obtained because of inability to gain access to the meter location, the customer may read his meter and furnish the Company the reading on cards supplied by the Company, or by telephone to the Company, in which case the bill will be rendered on the basis of such reading; otherwise, the Company will estimate the bill. No more than five (5) successive bills will be rendered on readings made by the customer.

15.1 INABILITY TO READ COMMERCIAL OR INDUSTRIAL METERS When scheduled readings of kilowatt-hour and demand meters are not obtained, the Company may render an interim statement for each month until the meters are read.

16. USE OF SERVICE BY CUSTOMER The customer shall use the service only at the premise where service is established; and after service has been established, shall notify the Company of any change in connected load, demand, or other conditions of use. By requesting service, the customer shall be deemed to represent that the Company's service shall be the sole source of electricity in each circuit to which such service is supplied, other than electricity concurrently produced as a by-product of another process or electricity produced utilizing renewable resources.

17. FLUCTUATIONS AND UNBALANCES The customer's use of electric service shall not cause fluctuating loads or unbalanced loads of sufficient magnitude to impair the service to other customers or to interfere with the proper operation of the Company's facilities. The Company may require the customer to make such changes in his equipment or use thereof, or to install such corrective equipment, as may be necessary to eliminate fluctuating or unbalanced loads; or, where the disturbances caused thereby may be eliminated more economically by changes in or additions to the Company's facilities, the Company will, at the request of the customer, provide the necessary corrective facilities at a reasonable charge. Payment will be made in full in advance for supplying special equipment installed under this Rule.

RULES AND REGULATIONS - (Continued)

MEASUREMENT AND USE OF SERVICE - (Continued)

18. REDISTRIBUTION All electric energy shall be consumed by the customer to whom the Company supplies and delivers such energy, except that (1) a customer operating a separate office building, and (2) any other customer who, upon showing that special circumstances exist, obtains the written consent of the Company may redistribute electric energy to tenants of such customer, but only if such tenants are not required to make a specific payment for such energy, except where such payments would encourage energy conservation. This rule shall not affect any practice undertaken prior to June 1, 1965. See Rule 41 for special requirements for residential dwelling units in a building.

19. CONTINUITY AND SAFETY The Company will use all reasonable care to provide safe and continuous delivery of electricity but shall not be liable for any damages arising through interruption of the delivery of electricity or for injury to persons or property resulting from the use of the electricity delivered.

BILLS AND NET PAYMENT PERIODS

20. BILLS Bills for electric delivery are due and payable upon presentation and may be paid at the general offices of the Company during its regular office hours or to any of its collecting agencies during the regular office hours of such agencies. When the meter readings are taken at other than monthly intervals or when the elapsed time between meter readings is substantially greater or less than one month, the rate values applicable to monthly delivery periods will be adjusted.

21. NET PAYMENT Payments made direct or received by mail at the payment receiving offices of the Company, or payments made direct to the Company's agencies, not later than the business day following the last day for net payment as shown on the bill, will be accepted by the Company in the net amount. Payments mailed on or before the last day for net payment as shown on the bill, will be accepted by the Company in the net amount, regardless of the date upon which payments are received. The date of mailing shall be determined by the Post Office date stamp on the enclosing envelope.

21.1 PAYMENT OF BILLS FOR RESIDENTIAL SERVICE Payments made direct at the payment receiving offices of the Company or payments made direct to the Company's agencies no later than the business day following 20 days after the mailing of the bill will be accepted by the Company in the amount billed. Payments mailed not later than 20 days after the mailing date of the bills will be accepted by the Company in the amount billed regardless of the date upon which payments are received. The date of mailing shall be determined by the Post Office date stamp on the enclosing envelope. If there is no postmark or if the postmark is illegible, the Company will not impose a Late Payment Charge if the payment is received within five days after the due date. When the due date for residential service occurs from the 21st day of the month through the 5th day of the following month, the due date may be extended upon request to the 6th day of the latter month for ratepayers receiving Social Security or equivalent monthly checks on or about the first of the month. A Late Payment Charge will be added for failure to make payment of the bill in accord with the above.

21.2 RETURNED CHECK CHARGE If a check received in payment of a Customer's account is returned to the Company unpaid by the Customer's bank and cannot be redeposited by the Company for payment, a \$20.00 charge for the returned check will be added to the Customer's account.

RULES AND REGULATIONS - (Continued)

COMPANY PROPERTY ON CUSTOMER'S PREMISES

22. ACCESS TO PREMISES Company representatives, who are properly identified, shall have full and free access to the customer's premises at all reasonable times for the purpose of reading Company meters, for inspection and repairs, for removal of Company property, or for any other purpose incident to the service. The customer should immediately communicate with the Company in case of any question as to the authority or credentials of Company representatives.

23. CUSTOMER'S RESPONSIBILITY The customer shall protect the property of the Company on the premises and shall not permit access thereto except by authorized representatives of the Company.

24. TAMPERING Where evidence is found that the service wires, meters, switch box or other appurtenances on the customer's premises have been tampered with, the customer shall be required to bear all costs incurred by the Company for investigations and inspections, and for such protective equipment as, in the judgment of the Company, may be necessary (including the relocation of inside metering equipment to an accessible outside location); and in addition, where the tampering has resulted in improper measurement of the electricity delivered, the customer shall be required to pay for such electric delivery service, and any Company supplied electricity, including interest at the Late Payment Charge rate, as the Company may estimate, from available information to have been used but not registered by the Company's meters.

25. REPAIRS OR LOSSES The customer shall pay the Company for any repairs to or any loss of the Company's property on the premises when such repairs are necessitated, or loss occasioned, by negligence on the part of the customer or failure to comply with the rules and regulations under which service is furnished.

DISCONTINUANCE, CURTAILMENT OR INTERRUPTION OF ELECTRIC SERVICE

26. ARREARS The Company upon reasonable notice may terminate the delivery of electricity and remove its equipment from the premises for nonpayment of an undisputed delinquent account. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

26.1 COLLECTION REVIEW The Company shall review accounts monthly for collection purposes. The Company shall pursue collection of residential accounts on a monthly basis where permitted by applicable regulations.

27. CONTRACTS OR APPLICATIONS Where service has been established without the customer first having executed a written contract or application, the Company reserves the right to terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case the customer refuses or neglects to execute a written contract or application when requested so to do by the Company. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

28. DEPOSITS The Company reserves the right to terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case the customer refuses or neglects to post a cash deposit when requested so to do by the Company, as provided under Rule 5. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

RULES AND REGULATIONS - (Continued)

DISCONTINUANCE, CURTAILMENT OR INTERRUPTION OF ELECTRIC SERVICE - (Continued)

29. UNDERGROUND SERVICE The Company reserves the right to terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice when the customer refuses or neglects to provide at his own expense the necessary facilities for receiving underground service, as provided under Rule 13.1. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

30. HAZARDOUS AND IMPROPER CONDITIONS The Company may terminate the delivery of electric service and remove its equipment from the premises upon reasonable notice if in the judgment of the Company the customer's installation has become dangerous or defective, or if the Company has received a notice from the proper authorities that the customer's equipment is dangerous or defective, or if the customer's equipment or use thereof injuriously affects the equipment of the Company or the Company's service to other customers. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

31. MISREPRESENTATIONS The Company reserves the right to terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case the customer has made misrepresentations to the Company with respect to the use of the electric service. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

32. REDISTRIBUTION The Company reserves the right to terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case the customer redistributes the electric service contrary to the provisions set forth in this tariff. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

33. INACCESSIBILITY The Company may terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case meter readers or other authorized representatives of the Company cannot gain admittance or are refused admittance to the premises for the purpose of reading meters, making repairs, making inspections, or removing Company property, or in case the customer interferes with Company representatives in the performance of their duties. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

34. TAMPERING The Company may terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case the Company's property on the premises has been interfered with, or in case evidence is found that the service wires, meters, switch-box or other appurtenances on the premises have been tampered with. When a residential ratepayer or residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

RULES AND REGULATIONS - (Continued)

DISCONTINUANCE, CURTAILMENT OR INTERRUPTION OF ELECTRIC SERVICE - (Continued)

35. REPAIRS AND LOSSES The Company may terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case the customer shall neglect or refuse to reimburse the Company for repairs to or loss of the Company's property on the premises when such repairs are necessitated, or loss occasioned, by negligence on the part of the customer. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

36. WRITS AND LEVIES The Company reserves the right to terminate the delivery of electricity and remove its equipment from the premises upon reasonable notice in case a Writ of Execution is issued against the customer, or in case the premises at which service is supplied is levied upon, or in case of assignment or act of bankruptcy on the part of the customer. When a residential ratepayer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, Uniform Billing Standards and Practices for Residential Utility Services.

37. INTERRUPTIONS FOR REPAIRS The Company reserves the right to curtail or temporarily interrupt customers' delivery of electricity upon prior notice of the cause and expected duration of interruption when it shall become necessary so to do in order that the Company may make repairs, replacements or changes in its equipment on or off the premises of the customers.

38. GOVERNMENTAL AUTHORITY The Company reserves the right to curtail, interrupt, or discontinue the delivery of electricity without notice in case it becomes necessary for the Company so to do in compliance with any order or request of any governmental authority. Notice of the cause and expected duration of the interruption will be given to affected customers as soon as possible.

39. CURTAILMENT WITHOUT NOTICE The Company reserves the right to curtail, interrupt or discontinue the delivery of electricity without prior notice to the extent required to meet emergencies. Notice of the cause and expected duration of the interruption will be given to affected customers as soon as possible.

39.1 EMERGENCY LOAD CONTROL Pursuant to order of Pennsylvania Public Utility Commission, the following provision is incorporated in this Tariff: Whenever the demands for power on all or part of the Company's system exceed or threaten to exceed the capacity then actually and lawfully available to supply such demands, or whenever system instability or cascading outages could result from actual or expected transmission overloads or other contingencies, or whenever such conditions exist in the system of another public utility or power pool with which the Company's system is interconnected and cause a reduction in the capacity available to the Company from that source or threaten the integrity of the Company's system, a load emergency situation exists. In such case, the Company shall take such reasonable steps as the time available permits to bring the demands within the then-available capacity or otherwise control load. Such steps shall include but shall not be limited to reduction or interruption of delivery of electricity to one or more customers, in accordance with the Company's procedures for controlling load.

The Company shall establish procedures for controlling load including schedules of load shedding priorities to be followed in compliance with the foregoing paragraph, may revise such procedures from time to time, and shall revise them if so required by Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its tariff for public inspection, and another such copy shall be kept on file with Commission's Bureau of Conservation, Economics and Energy Planning.

RULES AND REGULATIONS - (Continued)

DISCONTINUANCE, CURTAILMENT OR INTERRUPTION OF ELECTRIC SERVICE - (Continued)

39.2 EMERGENCY ENERGY CONSERVATION Pursuant to order of the Pennsylvania Public Utility Commission, the following provision is incorporated in this tariff:

Whenever events occur which are actually resulting, or in the judgment of the Company threaten to result, in a reduction in the supply of electricity which results from conditions such as a restriction of the fuel supplies available to the Company or its energy vendors, such that the amount of electric energy which the Company is able to supply is or will be adversely affected, by the loss of third party supply etc. an emergency energy conservation situation exists.

In the event of an emergency energy conservation situation, the Company shall take such reasonable measures as it believes necessary and proper to maintain the system until need to conserve has passed. Such measures may include, but shall not be limited to reduction, interruption, or suspension of delivery of electricity to one or more of its customers or classes of customers in accordance with the Company's procedure for emergency energy conservation.

The Company shall establish procedures for emergency energy conservation, including if it deems necessary, schedules of service interruption and suspension priorities to be followed as prescribed by the foregoing paragraph.

When a state of emergency is declared by the Governor, or other appropriate governmental authority, and during the period of that emergency, upon notification of the customer by the Company, the customer shall take the actions required by the procedures for emergency energy conservation. During the period of that emergency the appropriate customers will be billed under the provisions of Rider No. 17 - Emergency Energy Conservation.

The Company may revise such procedures from time to time, and shall revise them if so required by the Pennsylvania Public Utility Commission. A copy of such procedures or of the revision thereof currently in effect shall be kept available for public inspection at each office at which the Company maintains a copy of its tariff for public inspection, and another such copy shall be kept on file with the Commission's Bureau of Conservation, Economics and Energy Planning.

40. RECONNECTION CHARGE Where delivery service has been discontinued under the terms of Rules 26 through 36, inclusive, the Company reserves the right as a condition precedent to the reconnection of service to require the payment of all arrearages and a deposit and to require the payment of costs incurred by the Company to reconnect the service.

Where delivery of electricity has been discontinued upon the request of the customer and where the customer requests that service be reconnected at the same location within a period of one year from the date that delivery of electricity was discontinued, the Company reserves the right as a condition precedent to the reconnection of service to require the payment of all arrearages which will consist of the minimum charge applicable to such customer's delivery service during the period of discontinuance.

Where service to a non-residential customer has been terminated under the terms of Rules 30 and/or 34, and such condition was the direct result of tampering, the Company reserves the right as a condition precedent to the reconnection of service to require payment of all costs incurred by the Company for investigations and inspections, and for such protective equipment deemed necessary by the Company.

RULES AND REGULATIONS - (Continued)

DISCONTINUANCE, CURTAILMENT OR INTERRUPTION OF ELECTRIC SERVICE - (Continued)

41. PROHIBITION OF RESIDENTIAL MASTER METERING Each residential dwelling unit in a building must be individually metered by the Company for buildings connected after January 1, 1981. For the purposes of the Rule, a dwelling unit is defined as:

One or more rooms for the use of one or more persons as a housekeeping unit with space for eating, living, and sleeping, and permanent provisions for cooking and sanitation.

This Rule does not preclude the use of a single meter for the common areas and common facilities of a multi-tenant building.

This Rule shall not effect any practice undertaken prior to January 1, 1981.

GENERAL PROVISIONS

42. METER TESTING The Company will inspect or test the accuracy of a meter at the request of the customer for whom the meter registers service, but reserves the right to require payment of the fees set forth in 52 Pa. Code § 57.22 for such test.

43. OTHER SERVICES The Company may, where possible, provide and charge a reasonable fee for services including, but not limited to, energy audits, equipment inspections, technical reports and other similar services, at the request of the customer. Where possible, the Company will give an advanced, written estimate of the cost to provide the service.

44. SURGE PROTECTION SERVICE Surge Shield TM, a surge suppression device that will reduce or eliminate voltage surges, is available to customers pursuant to the terms and conditions set forth below. The device is mounted behind the meter socket at the customer's premise.

A. Availability

The Company will provide Surge Shield TM, to any customer with a 120/240 volt single-phase meter upon request, provided that the customer is determined by the Company to have an acceptable credit history.

B. Billing

A charge of \$4.65 per month for Surge Protection Service will be billed quarterly for a total of \$13.95. (One hundred and forty customers who elected monthly billing in the initial stage of the pilot program were subsequently offered a \$0.25 per quarter discount to accept quarterly billing. This discount will remain in effect for those customers.) At the Company's option, monthly billing may be offered in the future.

RULES AND REGULATIONS - (Continued)

GENERAL PROVISIONS- (Continued)

44. SURGE PROTECTION SERVICE - (Continued)

C. Payment Terms

Bills are due and payable on or before twenty (20) days for residential customers and fifteen (15) days for all other customers from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. Non-payment of the charges for Surge Protection Service will result in termination of the service and removal of the Surge Shield™ device. Termination of the Surge Protection Service will not impact the continuity of basic service.

D. Contract Term

An initial contract of one year is required, renewable thereafter from month to month.

E. Termination of the Service

Termination prior to the conclusion of the initial contract term will result in a \$50 service charge for removal of the device. Thereafter, a one month notice of termination is required and the customer will not be charged for removal of the device.

F. Liability

In the event that a customer's equipment and/or appliance is damaged as a direct result of the failure or malfunction of Surge Shield™, Duquesne will be responsible for the repair or replacement of the equipment and/or appliance for up to \$1,000 per occurrence.

RATE RSD - RESIDENTIAL SERVICE DELIVERY

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, and general household purposes.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

FIXED CHARGES

Customer Distribution Charge \$6.38
Competitive Transition Charge (CTC) Customer Specific

DELIVERY CHARGES

Transmission Charge 0.45 cents per Kilowatt-Hour
Distribution Charge..... 2.81 cents per Kilowatt-Hour
Competitive Transition Charge 0.72 cents per Kilowatt-Hour

ELECTRIC ENERGY CHARGES

CUSTOMERS WHO ARE ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Beginning January 1, 1999 some customers will be eligible to choose their electric energy suppliers with all customers having choice on January 1, 2001. Customers who are eligible to choose their supplier will be billed for their electric energy as a Full Service customer or a Delivery Service customer. Full Service customers are those who elect to purchase delivery services and all of their electric energy from the Company. Delivery Service customers are those who elect to purchase their delivery services from the Company and some or all of their electric energy from other electricity suppliers.

CUSTOMERS WHO ARE NOT ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Until a Customer is eligible to choose another energy supplier, the Customer will be charged for electric energy at the Company supplied electric energy charge. All customers will have choice of suppliers on January 1, 2001.

RATE RSD - RESIDENTIAL SERVICE DELIVERY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC ENERGY CHARGES - (Continued)

For The Period January 1 to December 31, 1999

Company Electric Energy Charge
All Kilowatt-Hours..... 1.86 cents per Kilowatt-Hour

OR

Other Electricity Supplier.....PRICES SET BY THE SUPPLIER

Any billing period in which a supplier becomes unavailable or the customer has not chosen a supplier, the Company will procure and deliver energy at current market prices.

MINIMUM CHARGE

The minimum Charge shall be the sum of the Customer Distribution Charge and the Customer Specific CTC.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before twenty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. The Charge shall be calculated on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period. A Late Payment Charge on a disputed bill may be reduced or eliminated by the Company, or upon order by the Commission, to facilitate payment by the disputing customer.

DEFINITIONS

CUSTOMER SPECIFIC COMPETITIVE TRANSITION CHARGE

The fixed Competitive Transition Charge (CTC) shall be derived from the specific Customer Baseline Usage (CBL) and the annual revenue calculated on the residential Rate RS and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of residential Rate RS calculated at the CBL less the sum of the: monthly fixed customer distribution charges, monthly transmission charges, monthly variable distribution charges, monthly variable competitive transition charges, monthly Company electric energy charge. The CTC will be divided by 12 and applied to each monthly bill through December 31, 2005. Customers will have their CTC calculated annually based on the Company Electric Energy Charge.

RATE RSD - RESIDENTIAL SERVICE DELIVERY - (Continued)

DEFINITIONS - (Continued)

CUSTOMER BASELINE USAGE

The CBL will normally be set equal to the monthly metered kilowatt-hour consumption at the customer's current premise for the 12 months ending December 31, 1996. Where 1996 monthly premise data is unavailable, the Company will make its best effort to estimate the CBL.

ANNUAL ENERGY CHARGE

The Company Electric Energy Charge will be derived from the market price obtained from a one year system energy sale. Each year during the Transition period, a one year sale may be conducted to determine the Electric Energy Charge for the next year. The Company reserves the right to set the Electric Energy Charge at prevailing market conditions in lieu of a system sale.

SPECIAL PROVISIONS

COMBINED RESIDENTIAL AND NON-RESIDENTIAL SERVICE

Where a portion of the service supplied is used for non-residential or non-farm purposes, the appropriate General Service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

RESIDENTIAL GARAGE

A separately metered 240 volts (or less) single phase service to a detached residential garage utilized solely for storing a residential customer's vehicle(s) and is located on the same property as the residential customer's dwelling unit will be considered residential use and may be serviced under the terms of this rate.

OPTIONAL BUDGET PAYMENT PLAN

An Optional Budget Payment Plan offers the ratepayer the option of paying a budget amount each month as estimated by the Company or the actual account balance of the current bill including any arrearages.

SUPPLIER CHANGES

The customer will be permitted to change suppliers with a minimum of 5 days notice to the Company. Supplier switches will occur on the next regularly scheduled read cycle date that occurs after 5 days from the receipt of consent from the customer and the new supplier.

RATE RHD - RESIDENTIAL SERVICE HEATING DELIVERY

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes, and as the sole primary method of space heating except that the space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

FIXED CHARGES

Customer Distribution Charge \$6.38

Competitive Transition Charge (CTC) Customer Specific

DELIVERY CHARGES

For the Billing Months of November through April:

Transmission Charge

First 500 Kilowatt-Hours at 0.52 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.35 cents per Kilowatt-Hour

Distribution Charge

First 500 Kilowatt-Hours at 3.16 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 2.10 cents per Kilowatt-Hour

Competitive Transition Charge

First 500 Kilowatt-Hours at 0.30 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.20 cents per Kilowatt-Hour

For the Billing Months of May through October:

Transmission Charge 0.52 cents per Kilowatt-Hour

Distribution Charge 3.16 cents per Kilowatt-Hour

Competitive Transition Charge 0.30 cents per Kilowatt-Hour

RATE RHD - RESIDENTIAL SERVICE HEATING DELIVERY (Continued)

MONTHLY RATE - (Continued)

ELECTRIC ENERGY CHARGES

CUSTOMERS WHO ARE ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Beginning January 1, 1999 some customers will be eligible to choose their electric energy suppliers with all customers having choice on January 1, 2001. Customers who are eligible to choose their supplier will be billed for their electric energy as a Full Service customer or a Delivery Service customer. Full Service customers are those who elect to purchase delivery services and all of their electric energy from the Company. Delivery Service customers are those who elect to purchase their delivery services from the Company and some or all of their electric energy from other electricity suppliers.

CUSTOMERS WHO ARE NOT ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Until a Customer is eligible to choose another energy supplier, the Customer will be charged for electric energy at the Company supplied electric energy charge. All customers will have choice of suppliers on January 1, 2001.

For The Period January 1 to December 31, 1999

Company Electric Energy Charge
All Kilowatt-Hours..... 1.84 cents per Kilowatt-Hour

OR

Other Electricity Supplier.....PRICES SET BY THE SUPPLIER

Any billing period in which a supplier becomes unavailable or the customer has not chosen a supplier, the Company will procure and deliver energy at current market prices.

MINIMUM CHARGE

The minimum Charge shall be the sum of the Customer Distribution Charge and the Customer Specific CTC.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before twenty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. The Charge shall be calculated on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period. A Late Payment Charge on a disputed bill may be reduced or eliminated by the Company, or upon order by the Commission, to facilitate payment by the disputing customer.

RATE RHD - RESIDENTIAL SERVICE HEATING DELIVERY (Continued)

DEFINITIONS

CUSTOMER SPECIFIC COMPETITIVE TRANSITION CHARGE

The fixed Competitive Transition Charge (CTC) shall be derived from the specific Customer Baseline Usage (CBL) and the annual revenue calculated on the residential Rate RH and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of residential Rate RH calculated at the CBL less the sum of the: monthly fixed customer distribution charges, monthly transmission charges, monthly variable distribution charges, monthly variable competitive transition charges, monthly Company electric energy charge. The CTC will be divided by 12 and applied to each monthly bill through December 31, 2005. Customers will have their CTC calculated annually based on the Company Electric Energy Charge.

CUSTOMER BASELINE USAGE

The CBL will normally be set equal to the monthly metered kilowatt-hour consumption at the customer's current premise for the 12 months ending December 31, 1996. Where 1996 monthly premise data is unavailable, the Company will make its best effort to estimate the CBL.

ANNUAL ENERGY CHARGE

The Company Electric Energy Charge will be derived from the market price obtained from a one year system energy sale. Each year during the Transition period, a one year sale may be conducted to determine the Electric Energy Charge for the next year. The Company reserves the right to set the Electric Energy Charge at prevailing market conditions in lieu of a system sale.

SPECIAL PROVISIONS

COMBINED RESIDENTIAL AND NON-RESIDENTIAL SERVICE

Where a portion of the service supplied is used for non-residential or non-farm purposes, the appropriate General Service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

RESIDENTIAL GARAGE

A separately metered 240 volt (or less) single phase service to a detached residential garage utilized solely for storing a residential customer's vehicle(s) and is located on the same property as the residential customer's dwelling unit will be considered residential use and may be served under the terms of this rate. To be served under the terms of this rate, the garage must use the Company's service as the sole primary method for space heating maintaining a winter time temperature of 55° F. or more.

RATE RHD - RESIDENTIAL SERVICE HEATING DELIVERY (Continued)

SPECIAL PROVISIONS - (Continued)

SPACE HEATING EQUIPMENT

Space heating equipment must be permanently installed, thermostatically controlled and must be approved by the Company.

Any renewable energy source system that produces electric energy may not be interconnected with circuits supplied by the Company's service except upon written approval from the Company.

OPTIONAL BUDGET PAYMENT PLAN

An Optional Budget Payment Plan offers the ratepayer the option of paying a budget amount each month as estimated by the Company or the actual account balance of the current bill including any arrearages.

SUPPLIER CHANGES

The customer will be permitted to change suppliers with a minimum of 5 days notice to the Company. Supplier switches will occur on the next regularly scheduled read cycle date that occurs after 5 days from the receipt of consent from the customer and the new supplier.

RATE RAD - RESIDENTIAL SERVICE ADD-ON HEAT PUMP DELIVERY

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes, and an add-on heat pump for space heating. Other energy sources may be used to supplement the add-on heat pump provided that the supplemental energy source is thermostatically controlled to operate only when the outdoor temperature falls to at least 40° F. and the add-on heat pump cannot provide the total heating requirements.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

FIXED CHARGES

Customer Distribution Charge \$6.38
Competitive Transition Charge (CTC) Customer Specific

DELIVERY CHARGES

For the Billing Months of November through April:

Transmission Charge
First 500 Kilowatt-Hours at 0.51 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.34 cents per Kilowatt-Hour

Distribution Charge
First 500 Kilowatt-Hours at 2.79 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 1.85 cents per Kilowatt-Hour

Competitive Transition Charge
First 500 Kilowatt-Hours at 0.68 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.45 cents per Kilowatt-Hour

For the Billing Months of May through October:

Transmission Charge 0.51 cents per Kilowatt-Hour
Distribution Charge 2.79 cents per Kilowatt-Hour
Competitive Transition Charge 0.68 cents per Kilowatt-Hour

RATE RAD - RESIDENTIAL SERVICE ADD-ON HEAT PUMP DELIVERY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC ENERGY CHARGES

CUSTOMERS WHO ARE ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Beginning January 1, 1999 some customers will be eligible to choose their electric energy suppliers with all customers having choice on January 1, 2001. Customers who are eligible to choose their supplier will be billed for their electric energy as a Full Service customer or a Delivery Service customer. Full Service customers are those who elect to purchase delivery services and all of their electric energy from the Company. Delivery Service customers are those who elect to purchase their delivery services from the Company and some or all of their electric energy from other electricity suppliers.

CUSTOMERS WHO ARE NOT ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Until a Customer is eligible to choose another energy supplier, the Customer will be charged for electric energy at the Company supplied electric energy charge. All customers will have choice of suppliers on January 1, 2001.

For The Period January 1 to December 31, 1999

Company Electric Energy Charge
All Kilowatt-Hours..... 1.85 cents per Kilowatt-Hour

OR

Other Electricity Supplier.....PRICES SET BY THE SUPPLIER

Any billing period in which a supplier becomes unavailable or the customer has not chosen a supplier, the Company will procure and deliver energy at current market prices.

MINIMUM CHARGE

The minimum Charge shall be the sum of the Customer Distribution Charge and the Customer Specific CTC.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before twenty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. The Charge shall be calculated on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period. A Late Payment Charge on a disputed bill may be reduced or eliminated by the Company, or upon order by the Commission, to facilitate payment by the disputing customer.

RATE RAD - RESIDENTIAL SERVICE ADD-ON HEAT PUMP DELIVERY - (Continued)

DEFINITIONS

CUSTOMER SPECIFIC COMPETITIVE TRANSITION CHARGE

The fixed Competitive Transition Charge (CTC) shall be derived from the specific Customer Baseline Usage (CBL) and the annual revenue calculated on the residential Rate RA and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of residential Rate RA calculated at the CBL less the sum of the: monthly fixed customer distribution charges, monthly transmission charges, monthly variable distribution charges, monthly variable competitive transition charges, monthly Company electric energy charge. The CTC will be divided by 12 and applied to each monthly bill through December 31, 2005. Customers will have their CTC calculated annually based on the Company Electric Energy Charge.

CUSTOMER BASELINE USAGE

The CBL will normally be set equal to the monthly metered kilowatt-hour consumption at the customer's current premise for the 12 months ending December 31, 1996. Where 1996 monthly premise data is unavailable, the Company will make its best effort to estimate the CBL.

ANNUAL ENERGY CHARGE

The Company Electric Energy Charge will be derived from the market price obtained from a one year system energy sale. Each year during the Transition period, a one year sale may be conducted to determine the Electric Energy Charge for the next year. The Company reserves the right to set the Electric Energy Charge at prevailing market conditions in lieu of a system sale.

SPECIAL PROVISIONS

COMBINED RESIDENTIAL AND NON-RESIDENTIAL SERVICE

Where a portion of the service supplied is used for non-residential or non-farm purposes, the appropriate General Service rate is applicable to all service; or, at the option of the customer, the wiring may be so arranged that the residential service may be separately metered and this rate is then applicable to the residential service only.

SPACE HEATING EQUIPMENT

Space heating equipment must be permanently installed, thermostatically controlled and must be approved by the Company.

The add-on heat pump and supplemental heating device must be equipped with a thermostatically operated control system which operates the add-on heat pump as the primary heating system until the outdoor temperature falls to at least 40° F.

RATE RAD - RESIDENTIAL SERVICE ADD-ON HEAT PUMP DELIVERY - (Continued)

SPECIAL PROVISIONS - (Continued)

OPTIONAL BUDGET PAYMENT PLAN

An Optional Budget Payment Plan offers the ratepayer the option of paying a budget amount each month as estimated by the Company or the actual account balance of the current bill including any arrearages.

SUPPLIER CHANGES

The customer will be permitted to change suppliers with a minimum of 5 days notice to the Company. Supplier switches will occur on the next regularly scheduled read cycle date that occurs after 5 days from the receipt of consent from the customer and the new supplier.

RATE GS/GMD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY

AVAILABILITY

Availability for all the standard electric service taken on a small or medium general service customer's premises for which a residential rate is not available.

MONTHLY RATE

FIXED CHARGES

Customer Distribution Charge \$9.07
Competitive Transition Charge (CTC) Customer Specific

DELIVERY CHARGES - DEMAND

Transmission Charge
First 5 Kilowatts or less of Demand No Charge
Excess Kilowatt of Demand \$0.93 per Kilowatt

Distribution Charge
First 5 Kilowatts or less of Demand No Charge
Excess Kilowatt of Demand \$4.45 per Kilowatt

Competitive Transition Charge
First 5 Kilowatts or less of Demand No Charge
Excess Kilowatt of Demand \$3.79 per Kilowatt

DELIVERY CHARGES - ENERGY

Transmission Charge
First 550 Kilowatt-Hours at 0.52 cents per Kilowatt-Hour
Next 750 Kilowatt-Hours at 0.48 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.20 cents per Kilowatt-Hour

Distribution Charge
First 550 Kilowatt-Hours at 2.48 cents per Kilowatt-Hour
Next 750 Kilowatt-Hours at 2.27 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.94 cents per Kilowatt-Hour

Competitive Transition Charge
First 550 Kilowatt-Hours at 2.12 cents per Kilowatt-Hour
Next 750 Kilowatt-Hours at 1.94 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.80 cents per Kilowatt-Hour

RATE GS/GMD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC ENERGY CHARGES

CUSTOMERS WHO ARE ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Beginning January 1, 1999 some customers will be eligible to choose their electric energy suppliers with all customers having choice on January 1, 2001. Customers who are eligible to choose their supplier will be billed for their electric energy as a Full Service customer or a Delivery Service customer. Full Service customers are those who elect to purchase delivery services and all of their electric energy from the Company. Delivery Service customers are those who elect to purchase their delivery services from the Company and some or all of their electric energy from other electricity suppliers.

CUSTOMERS WHO ARE NOT ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Until a Customer is eligible to choose another energy supplier, the Customer will be charged for electric energy at the Company supplied electric energy charge. All customers will have choice of suppliers on January 1, 2001.

For The Period January 1 to December 31, 1999

Company Electric Energy Charge
All Kilowatt-Hours..... 1.86 cents per Kilowatt-Hour

OR

Other Electricity Supplier.....PRICES SET BY THE SUPPLIER

Any billing period in which a supplier becomes unavailable or the customer has not chosen a supplier, the Company will procure and deliver energy at current market prices.

MINIMUM CHARGE

The minimum Charge shall be the sum of the Customer Distribution Charge and the Customer Specific CTC.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before twenty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. The Charge shall be calculated on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period. A Late Payment Charge on a disputed bill may be reduced or eliminated by the Company, or upon order by the Commission, to facilitate payment by the disputing customer.

RATE GS/GMD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY - (Continued)

DEFINITIONS

CUSTOMER SPECIFIC COMPETITIVE TRANSITION CHARGE

The fixed Competitive Transition Charge (CTC) shall be derived from the specific Customer Baseline Usage (CBL) and the annual revenue calculated on Rate GS/GM and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate GS/GM calculated at the CBL less the sum of the: monthly fixed customer distribution charges, monthly transmission charges, monthly variable distribution charges, monthly variable competitive transition charges, monthly Company electric energy charge. The CTC will be divided by 12 and applied to each monthly bill through December 31, 2005. Customers will have their CTC calculated annually based on the Company Electric Energy Charge.

CUSTOMER BASELINE USAGE

The CBL will normally be set equal to the monthly metered kilowatt and kilowatt-hour consumption at the customer's current premise for the 12 months ending December 31, 1996. Where 1996 monthly premise data is unavailable, the Company will make its best effort to estimate the CBL.

ANNUAL ENERGY CHARGE

The Company Electric Energy Charge will be derived from the market price obtained from a one year system energy sale. Each year during the Transition period, a one year sale may be conducted to determine the Electric Energy Charge for the next year. The Company reserves the right to set the Electric Energy Charge at prevailing market conditions in lieu of a system sale.

DETERMINATION OF DEMAND

The demand will be measured where a customer's monthly use exceeds 1,000 kilowatt-hours or where the demand is known to exceed 5 kilowatts. Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen-minute period of greatest kilowatt-hour use during the billing period. Individual demands which exceed 30 kilowatts will be adjusted for power factor by multiplying by

$$\left\{ 0.8 + \left[0.6 \frac{\text{Reactive Kilovolt - ampere hours}}{\text{Kilowatt - hours}} \right] \right\}$$

where such multiplier will be not less than 1.00 nor more than 2.00. The Billing Demand will be the sum of the individual demands of each metered service, adjusted for power factor as defined above.

RATE GS/GMD - GENERAL SERVICE SMALL AND MEDIUM DELIVERY - (Continued)

CONTRACT PROVISIONS

Contracts will be written for a period of not less than one year.

SPECIAL PROVISIONS

SUPPLIER CHANGES

The customer will be permitted to change suppliers with a minimum of 5 days notice to the Company. Supplier switches will occur on the next regularly scheduled read cycle date that occurs after 5 days from the receipt of consent from the customer and the new supplier.

RATE GMHD - GENERAL SERVICE MEDIUM HEATING DELIVERY

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE

FIXED CHARGES

Customer Distribution Charge \$9.07
Competitive Transition Charge (CTC) Customer Specific

DELIVERY CHARGES

For the Billing Months of October through May:

DELIVERY CHARGES - ENERGY

Transmission Charge
First 1,250 Kilowatt-Hours plus 150 Kilowatt-Hours for each
Kilowatt of Demand over 6 Kilowatts at 0.46 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.23 cents per Kilowatt-Hour

Distribution Charge
First 1,250 Kilowatt-Hours plus 150 Kilowatt-Hours for each
Kilowatt of Demand over 6 Kilowatts at 2.41 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 1.21 cents per Kilowatt-Hour

Competitive Transition Charge
First 1,250 Kilowatt-Hours plus 150 Kilowatt-Hours for each
Kilowatt of Demand over 6 Kilowatts at 1.01 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.50 cents per Kilowatt-Hour

RATE GMHD - GENERAL SERVICE MEDIUM HEATING DELIVERY - (Continued)

MONTHLY RATE - (Continued)

For the Billing Months of June through September:

DELIVERY CHARGES - DEMAND

Transmission Charge

First 5 Kilowatts or less of Demand No Charge
Excess Kilowatt of Demand \$1.08 per Kilowatt

Distribution Charge

First 5 Kilowatts or less of Demand No Charge
Excess Kilowatt of Demand \$5.71 per Kilowatt

Competitive Transition Charge

First 5 Kilowatts or less of Demand No Charge
Excess Kilowatt of Demand \$2.38 per Kilowatt

DELIVERY CHARGES - ENERGY

Transmission Charge

First 550 Kilowatt-Hours at 0.60 cents per Kilowatt-Hour
Next 750 Kilowatt-Hours at 0.55 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.23 cents per Kilowatt-Hour

Distribution Charge

First 550 Kilowatt-Hours at 3.20 cents per Kilowatt-Hour
Next 750 Kilowatt-Hours at 2.92 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 1.21 cents per Kilowatt-Hour

Competitive Transition Charge

First 550 Kilowatt-Hours at 1.33 cents per Kilowatt-Hour
Next 750 Kilowatt-Hours at 1.22 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.50 cents per Kilowatt-Hour

ELECTRIC ENERGY CHARGES

CUSTOMERS WHO ARE ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Beginning January 1, 1999 some customers will be eligible to choose their electric energy suppliers with all customers having choice on January 1, 2001. Customers who are eligible to choose their supplier will be billed for their electric energy as a Full Service customer or a Delivery Service customer. Full Service customers are those who elect to purchase delivery services and all of their electric energy from the Company. Delivery Service customers are those who elect to purchase their delivery services from the Company and some or all of their electric energy from other electricity suppliers.

RATE GMHD - GENERAL SERVICE MEDIUM HEATING DELIVERY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC ENERGY CHARGES - (Continued)

CUSTOMERS WHO ARE NOT ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Until a Customer is eligible to choose another energy supplier, the Customer will be charged for electric energy at the Company supplied electric energy charge. All customers will have choice of suppliers on January 1, 2001.

For The Period January 1 to December 31, 1999

Company Electric Energy Charge
All Kilowatt-Hours..... 1.86 cents per Kilowatt-Hour

OR

Other Electricity Supplier.....PRICES SET BY THE SUPPLIER

Any billing period in which a supplier becomes unavailable or the customer has not chosen a supplier, the Company will procure and deliver energy at current market prices.

MINIMUM CHARGE

The minimum Charge shall be the sum of the Customer Distribution Charge and the Customer Specific CTC.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before twenty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. The Charge shall be calculated on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period. A Late Payment Charge on a disputed bill may be reduced or eliminated by the Company, or upon order by the Commission, to facilitate payment by the disputing customer.

RATE GMHD - GENERAL SERVICE MEDIUM HEATING DELIVERY - (Continued)

DEFINITIONS

CUSTOMER SPECIFIC COMPETITIVE TRANSITION CHARGE

The fixed Competitive Transition Charge (CTC) shall be derived from the specific Customer Baseline Usage (CBL) and the annual revenue calculated on Rate GMH and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate GMH calculated at the CBL less the sum of the: monthly fixed customer distribution charges, monthly transmission charges, monthly variable distribution charges, monthly variable competitive transition charges, monthly Company electric energy charge. The CTC will be divided by 12 and applied to each monthly bill through December 31, 2005. Customers will have their CTC calculated annually based on the Company Electric Energy Charge.

CUSTOMER BASELINE USAGE

The CBL will normally be set equal to the monthly metered kilowatt and kilowatt-hour consumption at the customer's current premise for the 12 months ending December 31, 1996. Where 1996 monthly premise data is unavailable, the Company will make its best effort to estimate the CBL.

ANNUAL ENERGY CHARGE

The Company Electric Energy Charge will be derived from the market price obtained from a one year system energy sale. Each year during the Transition period, a one year sale may be conducted to determine the Electric Energy Charge for the next year. The Company reserves the right to set the Electric Energy Charge at prevailing market conditions in lieu of a system sale.

DETERMINATION OF DEMAND

The demand will be measured where a customer's monthly use exceeds 1,000 kilowatt-hours or where the demand is known to exceed 5 kilowatts. The demand will be the sum of individual demands of each metered standard service. Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen-minute period of greatest kilowatt-hour use during the billing period.

SPECIAL PROVISIONS

Any renewable energy source system that produces electric energy may not be interconnected with circuits supplied by the Company's service except upon written approval from the Company.

SUPPLIER CHANGES

The customer will be permitted to change suppliers with a minimum of 5 days notice to the Company. Supplier switches will occur on the next regularly scheduled read cycle date that occurs after 5 days from the receipt of consent from the customer and the new supplier.

RATE GLHD - GENERAL SERVICE LARGE HEATING DELIVERY

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE

For the Billing Months of October through May:

FIXED CHARGES

Customer Distribution Charge \$9.07
Competitive Transition Charge (CTC) Customer Specific

DELIVERY CHARGES - ENERGY

Transmission Charge
First 1,250 Kilowatt-Hours plus 150 Kilowatt-Hours for each
Kilowatt of Demand over 6 Kilowatts at 0.46 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.23 cents per Kilowatt-Hour

Distribution Charge
First 1,250 Kilowatt-Hours plus 150 Kilowatt-Hours for each
Kilowatt of Demand over 6 Kilowatts at 1.45 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.73 cents per Kilowatt-Hour

Competitive Transition Charge
First 1,250 Kilowatt-Hours plus 150 Kilowatt-Hours for each
Kilowatt of Demand over 6 Kilowatts at 1.96 cents per Kilowatt-Hour
Excess Kilowatt-Hours at 0.98 cents per Kilowatt-Hour

RATE GLHD - GENERAL SERVICE LARGE HEATING DELIVERY - (Continued)

MONTHLY RATE - (Continued)

For the Billing Months of June through September:

FIXED CHARGES FOR THE FIRST 300 KILOWATTS OR LESS OF DEMAND

Transmission Charge	\$662.21
Distribution Charge.....	\$2,073.77
Competitive Transition Charge (CTC)	\$2,791.02

DELIVERY CHARGES - DEMAND GREATER THAN 300 KILOWATTS

Transmission Charge	\$0.84 per Kilowatt
Distribution Charge.....	\$2.62 per Kilowatt
Competitive Transition Charge	\$3.53 per Kilowatt

DELIVERY CHARGES - ENERGY

Transmission Charge	0.23 cents per Kilowatt-Hour
Distribution Charge.....	0.73 cents per Kilowatt-Hour
Competitive Transition Charge	0.98 cents per Kilowatt-Hour

ELECTRIC ENERGY CHARGES

CUSTOMERS WHO ARE ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Beginning January 1, 1999 some customers will be eligible to choose their electric energy suppliers with all customers having choice on January 1, 2001. Customers who are eligible to choose their supplier will be billed for their electric energy as a Full Service customer or a Delivery Service customer. Full Service customers are those who elect to purchase delivery services and all of their electric energy from the Company. Delivery Service customers are those who elect to purchase their delivery services from the Company and some or all of their electric energy from other electricity suppliers.

RATE GLHD - GENERAL SERVICE LARGE HEATING DELIVERY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC ENERGY CHARGES - (Continued)

CUSTOMERS WHO ARE NOT ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Until a Customer is eligible to choose another energy supplier, the Customer will be charged for electric energy at the Company supplied electric energy charge. All customers will have choice of suppliers on January 1, 2001.

For The Period January 1 to December 31, 1999

Company Electric Energy Charge
All Kilowatt-Hours..... 1.86 cents per Kilowatt-Hour

OR

Other Electricity Supplier.....PRICES SET BY THE SUPPLIER

Any billing period in which a supplier becomes unavailable or the customer has not chosen a supplier, the Company will procure and deliver energy at current market prices.

MINIMUM CHARGE

The minimum Charge shall be the sum of the Customer Distribution Charge and the Customer Specific CTC.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before twenty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. The Charge shall be calculated on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period. A Late Payment Charge on a disputed bill may be reduced or eliminated by the Company, or upon order by the Commission, to facilitate payment by the disputing customer.

RATE GLHD - GENERAL SERVICE LARGE HEATING DELIVERY - (Continued)

DEFINITIONS

CUSTOMER SPECIFIC COMPETITIVE TRANSITION CHARGE

The fixed Competitive Transition Charge (CTC) shall be derived from the specific Customer Baseline Usage (CBL) and the annual revenue calculated on Rate GLH and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate GLH calculated at the CBL less the sum of the: monthly fixed customer distribution charges, monthly transmission charges, monthly variable distribution charges, monthly variable competitive transition charges, monthly Company electric energy charge. The CTC will be divided by 12 and applied to each monthly bill through December 31, 2005. Customers will have their CTC calculated annually based on the Company Electric Energy Charge.

CUSTOMER BASELINE USAGE

The CBL will normally be set equal to the monthly metered kilowatt and kilowatt-hour consumption at the customer's current premise for the 12 months ending December 31, 1996. Where 1996 monthly premise data is unavailable, the Company will make its best effort to estimate the CBL.

ANNUAL ENERGY CHARGE

The Company Electric Energy Charge will be derived from the market price obtained from a one year system energy sale. Each year during the Transition period, a one year sale may be conducted to determine the Electric Energy Charge for the next year. The Company reserves the right to set the Electric Energy Charge at prevailing market conditions in lieu of a system sale.

DETERMINATION OF DEMAND

The demand will be measured where a customer's monthly use exceeds 1,000 kilowatt-hours or where the demand is known to exceed 5 kilowatts. The demand will be the sum of individual demands of each metered standard service. Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen minute period of greatest kilowatt-hour use during the billing period.

SPECIAL PROVISIONS

Any renewable energy source system that produces electric energy may not be interconnected with circuits supplied by the Company's service except upon written approval from the Company.

SUPPLIER CHANGES

The customer will be permitted to change suppliers with a minimum of 5 days notice to the Company. Supplier switches will occur on the next regularly scheduled read cycle date that occurs after 5 days from the receipt of consent from the customer and the new supplier.

RATE GLD - GENERAL SERVICE LARGE DELIVERY

AVAILABILITY

Available for all the standard electric service taken on a customer's premises where the demand is not less than 300 kilowatts.

MONTHLY RATE

FIXED CHARGE

Competitive Transition Charge (CTC) Customer Specific

FIXED CHARGES FOR THE FIRST 300 KILOWATTS OR LESS OF DEMAND

Transmission Charge \$429.56

Distribution Charge..... \$1,546.19

Competitive Transition Charge (CTC) \$3,551.25

DELIVERY CHARGES - DEMAND GREATER THAN 300 KILOWATTS

Transmission Charge \$0.54 per Kilowatt

Distribution Charge..... \$1.96 per Kilowatt

Competitive Transition Charge \$4.49 per Kilowatt

DELIVERY CHARGES - ENERGY

Transmission Charge 0.15 cents per Kilowatt-Hour

Distribution Charge..... 0.54 cents per Kilowatt-Hour

Competitive Transition Charge 1.25 cents per Kilowatt-Hour

RATE GLD - GENERAL SERVICE LARGE DELIVERY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC ENERGY CHARGES

CUSTOMERS WHO ARE ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Beginning January 1, 1999 some customers will be eligible to choose their electric energy suppliers with all customers having choice on January 1, 2001. Customers who are eligible to choose their supplier will be billed for their electric energy as a Full Service customer or a Delivery Service customer. Full Service customers are those who elect to purchase delivery services and all of their electric energy from the Company. Delivery Service customers are those who elect to purchase their delivery services from the Company and some or all of their electric energy from other electricity suppliers.

CUSTOMERS WHO ARE NOT ELIGIBLE TO CHOOSE ELECTRIC ENERGY SUPPLIERS

Until a Customer is eligible to choose another energy supplier, the Customer will be charged for electric energy at the Company supplied electric energy charge. All customers will have choice of suppliers on January 1, 2001.

For The Period January 1 to December 31, 1999

Company Electric Energy Charge

All Kilowatt-Hours..... 1.85 cents per Kilowatt-Hour

OR

Other Electricity SupplierPRICES SET BY THE SUPPLIER

Any billing period in which a supplier becomes unavailable or the customer has not chosen a supplier, the Company will procure and deliver energy at current market prices.

MINIMUM CHARGE

The minimum Charge shall be the Customer Specific CTC and the sum of the Fixed Charges for the first 300 Kilowatts or less of Demand.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

LATE PAYMENT CHARGE

Bills will be calculated on the rates stated herein, and are due and payable on or before twenty days from the date of mailing of the bill to the ratepayer. The bill is overdue when not paid on or before the due date indicated on the bill. An overdue bill is subject to a Late Payment Charge of 1.25% interest per month on the full unpaid and overdue balance of the bill. The Charge shall be calculated on the overdue portions of the bill and shall not be charged against any sum that falls due during a current billing period. A Late Payment Charge on a disputed bill may be reduced or eliminated by the Company, or upon order by the Commission, to facilitate payment by the disputing customer.

RATE GLD - GENERAL SERVICE LARGE DELIVERY - (Continued)

DEFINITIONS

CUSTOMER SPECIFIC COMPETITIVE TRANSITION CHARGE

The fixed Competitive Transition Charge (CTC) shall be derived from the specific Customer Baseline Usage (CBL) and the annual revenue calculated on Rate GL and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate GL calculated at the CBL less the sum of the: monthly fixed customer distribution charges, monthly transmission charges, monthly variable distribution charges, monthly variable competitive transition charges, monthly Company electric energy charge. The CTC will be divided by 12 and applied to each monthly bill through December 31, 2005. Customers will have their CTC calculated annually based on the Company Electric Energy Charge.

CUSTOMER BASELINE USAGE

The CBL will normally be set equal to the monthly metered kilowatt and kilowatt-hour consumption at the customer's current premise for the 12 months ending December 31, 1996. Where 1996 monthly premise data is unavailable, the Company will make its best effort to estimate the CBL.

ANNUAL ENERGY CHARGE

The Company Electric Energy Charge will be derived from the market price obtained from a one year system energy sale. Each year during the Transition period, a one year sale may be conducted to determine the Electric Energy Charge for the next year. The Company reserves the right to set the Electric Energy Charge at prevailing market conditions in lieu of a system sale.

DETERMINATION OF DEMAND

Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen-minute period of greatest kilowatt-hour use during the billing period. Individual demands which exceed 30 kilowatts will be adjusted for power factor by multiplying by

$$\left\{ 0.8 + \left[0.6 \frac{\text{Reactive Kilovolt - ampere hours}}{\text{Kilowatt - hours}} \right] \right\}$$

where such multiplier will be not less than 1.00 nor more than 2.00. The Billing Demand will be the sum of the individual demands of each metered service, adjusted for power factor as defined above, but not less than 50% of the Contract On-Peak Demand nor less than 300 kilowatts, whichever is the greater.

FILE

CONTINUED