RATE GLD - GENERAL SERVICE LARGE DELIVERY - (Continued)

CONTRACT DEMAND

The Contract Demand is the maximum electrical capacity in kilowatts which the Company shall be required by the contract to make available to the customer.

The Customer shall not establish a demand greater than 105 percent of the individual demands specified in the customer's contract unless written approval shall first have been obtained from the Company. If the customer establishes a repeated pattern of exceeding the Contract Demand, the Contract Demand may be raised to the highest demand established for the remaining term of the contract.

Contracts will be written for a period of not less than one year.

Where the customer has established an energy management and conservation program and has demonstrated to the satisfaction of the Company that such program has resulted in a reduced demand, the Company will, upon the customer's request, amend the contract to reflect such reduced demand for the purpose of calculating the Minimum Charge, but in no case shall the Billing Demand be reduced to less than 300 kilowatts if the customer remains on this rate.

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 LD - LARGE POWER SERVICE DELIVERY

AVAILABILITY

Available for all the standard electric service taken on a customer's premises where the Contract Demand is not less than 5,000 kilowatts.

MONTHLY RATE

FIXED CHARGE

Competitive Transition Charge (CTC)	Customer Specific

FIXED CHARGES FOR THE FIRST 5,000 KILOWATTS OR LESS OF DEMAND

Transmission Charge	$6,797.70
Distribution Charge	$21,616.25
Competitive Transition Charge (CTC)	$42,875.05

NEXT 10,000 KILOWATTS

Transmission Charge	$0.55 per Kilowatt
Distribution Charge	$1.74 per Kilowatt
Competitive Transition Charge (CTC)	$3.44 per Kilowatt

NEXT 25,000 KILOWATTS

Transmission Charge	$0.53 per Kilowatt
Distribution Charge	$1.69 per Kilowatt
Competitive Transition Charge (CTC)	$3.35 per Kilowatt

EXCESS KILOWATTS

Transmission Charge	$0.52 per Kilowatt
Distribution Charge	$1.64 per Kilowatt
Competitive Transition Charge (CTC)	$3.26 per Kilowatt

RATE LD - LARGE POWER SERVICE DELIVERY - (Continued)

MONTHLY RATE - (Continued)

DELIVERY CHARGES - ENERGY

First 750,000 Kilowatt-Hours
plus 400 Kilowatt-Hours per Kilowatt of Demand

Transmission Charge	0.19 cents per Kilowatt-Hour
Distribution Charge	0.59 cents per Kilowatt-Hour
Competitive Transition Charge (CTC)	1.17 cents per Kilowatt-Hour

Next 150 Kilowatt-Hours per Kilowatt of Demand

Transmission Charge	0.07 cents per Kilowatt-Hour
Distribution Charge	0.22 cents per Kilowatt-Hour
Competitive Transition Charge (CTC)	0.43 cents per Kilowatt-Hour

Excess Kilowatt-Hours

Transmission Charge	0.05 cents per Kilowatt-Hour
Distribution Charge	0.15 cents per Kilowatt-Hour
Competitive Transition Charge (CTC)	0.30 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 LD - LARGE POWER 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 ..... 1.85 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 Customer Specific CTC and the sum of the Fixed Charges for the first 5,000 Kilowatts or less of demand.

RIDERS

Bills rendered under this schedule are subject to the charges stated in any applicable rider.

UNTRANSFORMED SERVICE CREDIT

Where the customer furnishes all necessary equipment to take untransformed delivery at 11,500 volts or higher, in strict accordance with the Company's standards and specifications, a credit based upon the individual demand of the untransformed circuit shall be as follows:

11,500 or 23,000 Volt Service ..... $39.75 plus 7.0 cents per Kilowatt
69,000 Volt Service or Higher ..... 9.1 cents per Kilowatt

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 LD - LARGE POWER SERVICE 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 L and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate L 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 70% of the Contract On-Peak Demand nor less than 5,000 kilowatts, whichever is the greater.

CONTRACT DEMAND

The Contract Demand is the maximum electrical capacity in kilowatts which the Company shall be required by the contract to deliver to the customer.

The customer shall not establish a demand greater than 105 percent of the individual demands specified in the customer's contract unless written approval shall first have been obtained from the Company. If the customer establishes a repeated pattern of exceeding the Contract Demand, the Contract Demand may be raised to the highest demand established for the remaining term of the contract.

RATE LD - LARGE POWER SERVICE DELIVERY - (Continued)

CONTRACT PROVISIONS

Contracts shall be written for an original term of not less than five years for Contract Demand of 100,000 kilowatts or less, and not less than ten years for Contract Demands in excess of 100,000 kilowatts. Effective on January 26, 1985, such contracts shall continue in force after the expiration of the original term until one year following the date of written notice of cancellation by either party. Such notice of cancellation may not be given earlier than one year before the expiration of the original term. Contract cancellations for which written notice of such was received prior to January 26, 1985, shall be effective on January 26, 1986, unless cancellation under such notice would have been effective under the prior three year cancellation provision of Rate LD before January 26, 1986, in which case the appropriate contract cancellation date shall prevail.

When a customer takes delivery at 69 Kv or higher for delivery into its own electric system operated at either of such voltages, and has a Contract Demand of at least 100,000 kilowatts, the customer may apply for service at two or more delivery points interconnected by the customer's facilities. If the Company is satisfied that such multiple delivery points will protect the Company from substantial loss of load and otherwise will be consistent with operation of the Company's system, it will provide such multiple delivery points. In such case the various delivery points will be billed as if metered at one point, but the 5,000 kilowatt, 10,000 kilowatt and 25,000 kilowatt blocks of the Capacity Charge, and the 750,000 kilowatt-hour block of the Energy Charge, will be multiplied by the number of delivery points before the rates stated for them are applied.

The Company reserves the right to refuse contracts hereunder if, in its judgement, its generating or transmission capacity is no more than adequate to meet the requirements of its existing customers.

Where the customer has established an energy management and conservation program and has demonstrated to the satisfaction of the Company that such program has resulted in a reduced demand, the Company will, upon the customer's request, amend the contract to reflect such reduced demand for the purpose of calculating the Minimum Charge, but in no case shall the Billing Demand be reduced to less than 5,000 kilowatts if the customer remains on this rate.

VOLTAGE CONTROL PROVISION

The customer shall be required to operate his equipment in such a manner that the voltage fluctuations produced thereby on the Company's system shall not exceed the following limits, the measurements to be made at the Company's substation nearest (electrically) the customer.

1. Instantaneous voltage fluctuations, defined as a change in voltage consuming two seconds or less, shall not exceed 1-1/4% more than six times a day, of which not more than one such fluctuation shall occur between 6:00 PM and midnight, and in no case shall such fluctuations exceed 3%.

2. Periodic voltage fluctuations, where the change in voltage consumes a period from 2 seconds to 1 minute, shall not exceed 1-1/4% more than five times an hour, and in no case shall such fluctuations exceed 3%.

RATE LD - LARGE POWER SERVICE DELIVERY - (Continued)

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 HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY

AVAILABILITY

Available to customers with Contract On-Peak Demands greater than 30,000 kilowatts where service is supplied at 69,000 volts or higher.

MONTHLY RATE

FIXED CHARGE

Competitive Transition Charge (CTC) ..... Customer Specific

FIXED CHARGES FOR THE FIRST 30,000 KILOWATTS OR LESS OF DEMAND

Transmission Charge $37,954.56

Distribution Charge..... $76,367.59

Competitive Transition Charge (CTC) $216,213.85

DELIVERY CHARGES -DEMAND EXCESS KILOWATTS

Transmission Charge ..... $1.37 per Kilowatt

Distribution Charge..... $2.75 per Kilowatt

Competitive Transition Charge (CTC) ..... $7.80 per Kilowatt

DELIVERY CHARGES - ENERGY

On-Peak

Transmission Charge ..... 0.30 cents per Kilowatt-Hour

Distribution Charge..... 0.61 cents per Kilowatt-Hour

Competitive Transition Charge (CTC) ..... 1.72 cents per Kilowatt-Hour

Off-Peak

Transmission Charge ..... 0.06 cents per Kilowatt-Hour

Distribution Charge..... 0.12 cents per Kilowatt-Hour

Competitive Transition Charge (CTC) ..... 0.33 cents per Kilowatt-Hour

RATE HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY - *(Continued)*

MONTHLY RATE - (Continued)

DELIVERY CHARGES - ENERGY - (Continued)

WHERE

Monthly Kilowatt-Hours billed at the Off-Peak Kilowatt-Hour Charge cannot exceed 75% of the total Kilowatt-Hours.

NOR

Monthly Kilowatt-Hours billed at the Off-Peak Kilowatt-Hour Charge cannot exceed 500 Kilowatt-Hours per Kilowatt of the Billing Demand.

All excess Off-Peak Energy will be billed at the on-peak delivery charges.

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 Customer Specific CTC and the sum of the Fixed Charges for the first 30,000 kilowatts or less of demand.

RATE HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY - (Continued)

MONTHLY RATE - (Continued)

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 Rate HVPS and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate HVPS 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.

RATE HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY - (Continued)

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 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 70% of the Contract On-Peak Demand, nor less than 33 1/3% of the Contract Off-Peak Demand nor less than 30,000 kilowatts, whichever is the greater.

ON-PEAK AND OFF-PEAK CONTRACT DEMAND

The Contract On-Peak Demand is the maximum electrical capacity in kilowatts which the Company shall be required by the contract to deliver or deliver and supply during the On-Peak hours to the customer.

The Contract Off-Peak Demand is the maximum electrical capacity in kilowatts which the Company shall be required by the contract to deliver or deliver and supply during the Off-Peak hours to the customer.

The customer shall not establish a demand greater than 105 percent of the individual demands specified in the customer's contract unless written approval shall first have been obtained from the Company. If the customer establishes a repeated pattern of exceeding the Contract Demand, the Contract Demand may be raised to the highest demand established for the remaining term of the contract.

DEMANDS AND ENERGIES

The On-Peak Demand is the demand during on-peak hours.

The Off-Peak Demand is the demand during off-peak hours.

The Billing Demand is the On-Peak Demand except where the Off-Peak Demand is more than three times the On-Peak Demand. Then the Billing Demand will be one-third (33 1/3%) of the Off-Peak Demand.

Demands and energies will be determined on an individual demand basis and corresponding quantities will be combined to obtain demands and energies for billing purposes.

RATE HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY - (Continued)

ON-PEAK AND OFF-PEAK HOURS

The following hours will be designated as on-peak hours:

Monday through Thursday	Friday
10:00 a.m. to 9:00 p.m	10:00 a.m. to 5:00 p.m.

The remaining hours including the generally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be designated as off-peak hours. The Company may, upon written notice to customers taking service under this rate and upon filing same with the Pennsylvania Public Utility Commission, make such changes in the on-peak hours as it may from time to time deem necessary.

CONTRACT PROVISIONS

Contracts shall be written for an original term of not less than five years for Contract Demand of 100,000 kilowatts or less, and not less than ten years for Contract Demands in excess of 100,000 kilowatts. Such contracts shall continue in force after the expiration of the original term until one year following the date of written notice of cancellation by either party. Such notice of cancellation may not be given earlier than one year before the expiration of the original term.

The Company reserves the right to refuse contracts hereunder if, in its judgement, its generating or transmission capacity is no more than adequate to meet the requirements of its existing customers.

Where the customer has established an energy management and conservation program and has demonstrated to the satisfaction of the Company that such program has resulted in a reduced demand, the Company will, upon the customer's request, amend the contract to reflect such reduced demand for the purpose of calculating the Minimum Charge, but in no case shall the Billing Demand be reduced to less than 30,000 kilowatts if the customer remains on this rate.

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 HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY - (Continued)

VOLTAGE CONTROL PROVISION

The customer shall be required to operate his equipment in such a manner that the voltage fluctuations produced thereby on the Company's system shall not exceed the following limits, the measurements to be made at the Company's substation nearest (electrically) the customer.

1. Instantaneous voltage fluctuations, defined as a change in voltage consuming two seconds or less, shall not exceed 1-1/4% more than six times a day, of which not more than one such fluctuation shall occur between 6:00 p.m. and midnight, and in no case shall such fluctuations exceed 3%.

2. Periodic voltage fluctuations, where the change in voltage consumes a period from 2 seconds to 1 minute, shall not exceed 1-1/4% more than five times an hour, and in no case shall such fluctuations exceed 3%.

INTERRUPTIBLE SERVICE

A customer who is supplied electricity from the Company may contract for interruptible load by agreeing to the "Special Terms and Conditions" listed below. The Capacity Charge of this rate will be reduced by a $2.03 per kW credit of contracted interruptible load.

SPECIAL TERMS AND CONDITIONS

To be eligible for Interruptible Service the customer must agree to the following terms and conditions:

1. The Company must have unilateral, irrevocable control of the customers equipment used to disconnect the interruptible load from its electric supply. The irrevocable control of the customers equipment used to disconnect the interruptible load applies to the period of the interruption.

2. The system would be designed to provide a warning to the customer of imminent interruptions. However, Duquesne Light would reserve the right to interrupt service to the interruptible load at any time without advance notice to the customer. Subject to this reservation, the Company will endeavor to make available to the customer capacity equal to the demand specified in the contract for at least 80% of the hours in any calendar month and 90% of the hours in any calendar year. In all cases it is the customers responsibility to restore the load following notification from Duquesne that the interruption period is over.

RATE HVPSD - HIGH VOLTAGE POWER SERVICE DELIVERY - (Continued)

SPECIAL TERMS AND CONDITIONS - (Continued)

3. The Company shall not be liable for any loss, cost, damage, or expense to customer caused by the disconnection of contracted-for interruptible load from its electric supply.

4. The interruptible portion must be load from facilities that the customer utilizes on a regular basis between 10:00 a.m. and 9:00 p.m. on each day throughout the year except Saturdays, Sundays and generally observed holidays. If the customer ceases to utilize such facilities for more than 60 days, the customer must notify the Company.

5. Customers will be responsible for installing breakers, an interfacing relay, and for making any necessary wiring, structural, or equipment location changes to allow isolation of the interruptible portion of the load without affecting the remainder of the service.

6. The Company will install, own (or control the lease), and maintain the transmitter, communication channel, receiver, and relaying equipment utilized to operate the customer-owned and installed and customer-maintained circuit breaker utilized to interrupt the interruptible load. The Company will install appropriate monitoring equipment on the interruptible service or circuit breaker to enable the Company to determine at a later date that the interruptible load was interrupted. The customer is responsible for the safety and proper operation of the customer's circuit breaker and associated equipment.

7. Interruptible load will be interrupted as a result of overloads on the transmission, subtransmission, and distribution systems on exactly the same basis as firm load customers are interrupted.

8. Where the customer's entire load is under a load management device, the customer must make provisions so that the load management device does not recognize the loss of the interruptible load.

9. The amount of interruptible load that is available will be determined solely by the Company and will be contracted for a first-come first-served basis.

FACILITIES CHARGE

Customer must pay for all new or additional facilities installed on the premises with the exception of meters and metering equipment.

RATE SMD - STREET LIGHT MUNICIPAL DELIVERY

AVAILABILITY

Available for mercury vapor and high pressure sodium lighting of public streets, highways, bridges, parks and similar public places, for normal dusk to dawn operation of approximately 4,200 hours per year.

(Available for mercury vapor street lighting only where served prior to January 30, 1983, and continuously thereafter at the same location).

MONTHLY RATE

Bills shall be rendered monthly according to the following rates:

Nominal Lamp Wattage	70	100	150	175	250	400	1,000
Monthly Rate Per Unit							
Mercury Vapor	----	$14.90	----	$19.46	$24.27	$32.94	$71.30
Sodium Vapor	$15.09	$19.30	$22.92	----	$33.53	$43.84	$91.79

No charge is made for wood poles used jointly for street lighting and the support of the Company's general distribution system or for tubular steel poles, trolley type, used jointly for street lighting and the support of trolley span wires.

(Where wood poles have been installed exclusively for street lighting use prior to June 29, 1973, and used continuously thereafter, an additional charge of $1.31 per pole per month will be made. For wood poles installed exclusively for street lighting use after June 29, 1973, see SPECIAL TERMS AND CONDITIONS).

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 thirty 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.

SPECIAL TERMS AND CONDITIONS

1. The above charges include installation of standard Company facilities including lamps, fixtures or luminaries, brackets and ballasts, all when installed on the overhead distribution system. The above charges include normal operation and maintenance. Normal operation and maintenance does not include periodic tree trimming around the fixture or luminaire.

RATE SMD - STREET LIGHT MUNICIPAL DELIVERY - (Continued)

SPECIAL TERMS AND CONDITIONS - (Continued)

2. Where it is necessary to install wood, metal, or ornamental poles, or other special facilities or services not in conformance with the Company's standard overhead practice, the additional cost shall be borne by the customer. Title to all facilities, except as noted below, shall vest in the Company.

3. All facilities used in providing street lighting service shall be and remain the property of the Company and may be removed upon termination of service, except that poles, ducts, conduits, manholes and junction boxes shall be the property of and maintained by the customer if they are an integral part of bridges, viaducts or similar structures, or highway project constructed by the joint participation of the customer and other governmental agencies.

4. The customer agrees that the facilities installed under this rate shall not be removed or converted, or the use thereof discontinued by the customer, except upon payment to the Company of the original investment in such facilities, less depreciation to the date of discontinuance of such facilities, less salvage, plus the cost of removal.

RATE SED - STREET LIGHTING ENERGY DELIVERY

AVAILABILITY

Available for the entire electric energy requirements of municipal street lighting systems where the municipality has not less than 15,000 street lamp installations and provides for the ownership, operation, and maintenance of its own street lamp installations and takes its entire energy requirements for street lighting under this rate.

MONTHLY RATE

FIXED CHARGES

Competitive Transition Charge (CTC) ..... Customer Specific

DELIVERY CHARGES

Transmission Charge ..... 0.30 cents per Kilowatt-Hour

Distribution Charge..... 9.06 cents per Kilowatt-Hour

Competitive Transition Charge ..... 0.00 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 SED - STREET LIGHTING ENERGY 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 ..... 1.81 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 Customer Specific CTC.

DETERMINATION OF ENERGY FOR BILLING PURPOSES

Series Street Lights

Applicable to the supply of series street lighting energy delivered to the street lighting fixtures at 7.5 amperes unless otherwise agreed upon.

The energy delivered or delivered and supplied each month shall be the product of the connected load in kilowatts as of the fifteenth day of the month for which billed and 350 hours per month, which is the monthly average of the annual burning hours. The connected load on the primary side of the substation or pole-type constant current transformers will be the sum of the rated wattages of all lamps connected, including the rated wattages of their individual transformers and ballasts, if any, and subject to values of circuit efficiency of 85 percent.

Multiple Street Lights

Applicable to the supply of multiple street lighting energy delivered to the street lighting fixtures at 120/240 volts unless otherwise agreed upon.

(a) For Standard Dusk to Dawn Operation Where the Customer Supplies Controls Approved by the Company. The energy delivered each month shall be the product of the connected load in kilowatts as of the fifteenth day of the month for which billed and 350 hours per month, which is the monthly average of the annual burning hours. The connected load shall be the sum of the rated wattages of all lamps connected, including the rated wattages of their individual ballasts, subject to power factor correction, if any.

RATE SED - STREET LIGHTING ENERGY DELIVERY - (Continued)

MONTHLY RATE - (Continued)

DETERMINATION OF ENERGY FOR BILLING PURPOSES - (Continued)

Multiple Street Lights - (Continued)

(b) For Other than Standard Dusk to Dawn Operation. The energy delivered or delivered and supplied each month shall be the product of the connected load in kilowatts as of the fifteenth day of the month for which billed and 730 hours per month or less as may be agreed upon. The connected load shall be the sum of the rated wattages of all lamps connected, including the rated wattages of their individual ballasts, subject to power factor correction, if any.

CREDIT FOR OUTAGE

Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service and the Customer will use reasonable diligence to protect the lighting system. In lieu of determination of the actual lamp-hour outages resulting from a failure of any light to burn for any reason, a deduction of 0.2% of the delivery charges or delivery and energy charges will be made on the monthly bill.

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.

CHARGES FOR SPECIAL FACILITIES

Conduit used exclusively for street lighting service between lamps in the customer's area and installed prior to July 1, 1969.....$0.0100 per foot

Cable used exclusively for street lighting service between lamps in the customer's area .....$0.0030 per foot

Parkway-type cable used exclusively for street lighting service between lamps in the customer's area .....$0.0080 per foot

RATE SED - STREET LIGHTING ENERGY DELIVERY - (Continued)

MONTHLY RATE - (Continued)

CHARGES FOR SPECIAL FACILITIES - (Continued)

Standard junction boxes, for street lighting service located within the customer's area and installed prior to July 1, 1969 ..... $0.4528 each

Insulating transformers ..... $0.4126 each

Ballasts for Mercury Vapor Lamps ..... $0.9056 each

The total of the Charges for Special Facilities shall be multiplied by 0.97 in order to express such charges at net prices.

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 SE and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate SE 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.

RATE SED - STREET LIGHTING ENERGY DELIVERY - (Continued)

SPECIAL PROVISIONS

1. Ballasts for multiple mercury vapor street lights, when installed by the customer, shall be power factor corrected, having a power factor of not less than 90 percent. For ballasts not so corrected, the wattage of each lamp plus ballasts shall be increased by the following ratio: 90% divided by the actual power factor, expressed in percent, of the lamp plus the ballast.

2. Series street lighting circuits will be energized and de-energized in accordance with an agreed upon schedule of burning hours, except where such circuits are controlled by photo electric cells. During other hours, circuits will not be energized except upon sufficient notice to the customer.

3. On all poles, except ornamental poles used exclusively for street lighting purposes, the Company will terminate its facilities at the bracket to which the lighting fixture is attached. On ornamental poles, used exclusively for street lighting purposes, the Company will terminate its facilities at the top of the pole if served from overhead circuits or at the bottom of the pole if served from the underground system.

4. The Company, to protect continuity of service, the general public, and the safety of men engaged in work on poles, reserves the right to install insulating transformers between the Company's circuit and the wiring of the customer's installation. Where insulating transformers are installed, charges will be made therefore as herein before specified.

5. The customer upon request shall supply the Company periodically, but not more often than at six month intervals, with certified tests made by the Electrical Testing Laboratories, Inc. of New York, or a similar accredited organization, showing the mean life input in watts for each size and type of lamp, and the wattage and power factor for each size and type of mercury vapor ballast used by the customer in street lamp installations served under this rate.

6. Energy will normally be supplied under this rate by overhead circuits, but if the Company is required to supply or the customer requests delivery service from underground facilities, the specified unit charges for underground facilities will apply.

7. All installations, on and after July 1, 1969, of standard junction boxes used for street lighting service and of conduit and multiple service cable used exclusively for street lighting service will be installed, owned and maintained by the customer.

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 SHD - STREET LIGHTING HIGHWAY DELIVERY

TERM OF CONTRACT

Contracts under this rate shall be for a term of not less than ten years.

AVAILABILITY

Available for high intensity discharge lighting of state highways for normal dusk to dawn operation of approximately 4,200 hours per year where the highway lighting system acceptable to Duquesne Light Company is installed by the State and ownership of the entire highway lighting system has been transferred to the Company for a nominal consideration.

MONTHLY RATE

Bills shall be rendered monthly according to the following rates:

Nominal Lamp Wattage	100	150	175	200	250	400	1,000
Monthly Rate Per Unit							
Mercury Vapor	----	----	$12.88	----	$16.79	$24.71	$55.60
Sodium Vapor	$12.33	$15.18	----	$18.03	$20.86	$29.39	$65.94

SPECIAL TERMS AND CONDITIONS

1. The above charges include operation, normal maintenance and replacement of the entire highway lighting system including conduit, cable, wire, ornamental poles, brackets, fixtures, lamps and photo electric controls.

2. Energy shall be supplied at a standard 120/240 or 230/460 volts from a single point or multiple points of supply satisfactory to the Company. Fixtures operating at higher voltages will not be acceptable.

3. The highway lighting system design shall include proper control devices to energize the system, such as individual photo electric controls.

4. If additional highway lighting is to be added to an existing highway lighting system, it shall be installed completely by the customer or the Company will install such facilities at the customer's expense with ownership transferred to the Company for a nominal consideration.

5. In accepting conduit, junction boxes, etc. installed by the State or other governmental agency in bridges, and bridge approaches, the Company accepts no liability for damage to concrete due to deteriorating conduit or junction boxes.

RATE SHD - STREET LIGHTING HIGHWAY DELIVERY - (Continued)

SPECIAL TERMS AND CONDITIONS - (Continued)

6. The State Department of Transportation or *other governmental* agency shall provide the necessary drawings of the entire highway lighting system to the Company specifying the type of equipment so that acceptability can be established before contracts are awarded.

7. The State Department of Transportation or other governmental agency shall furnish any requisite authority necessary to provide for the installation, operation and maintenance of the entire highway lighting system within the highway right-of-way including authority for equipment to stop on the paved portion of the highway.

8. Maintenance and/or replacement of poles and pole equipment in excess of 35 feet is not included, but will be maintained and/or replaced on a time and material basis by the Company. Charges for this will be reimbursed by the customer. All poles in excess of 35 feet high must be equipped with lowering device equipment so that the lighting equipment can be maintained from the ground.

TERM OF CONTRACT

Contracts under this rate shall be for a term of not less than five years.

RATE MTSD - MUNICIPAL TRAFFIC SIGNALS DELIVERY

AVAILABILITY

Available to any municipality using the Company's standard service at each point of connection for traffic signal lighting installed, owned, and maintained by the customer.

MONTHLY RATE

FIXED CHARGES

Customer Distribution Charge $8.91

Competitive Transition Charge (CTC) ..... Customer Specific

DELIVERY CHARGES - ENERGY

Transmission Charge
- First 1,300 Kilowatt-Hours ..... 0.31 cents per Kilowatt-Hour
- Excess Kilowatt-Hours ..... 0.11 cents per Kilowatt-Hour

Distribution Charge
- First 1,300 Kilowatt-Hours ..... 0.74 cents per Kilowatt-Hour
- Excess Kilowatt-Hours ..... 0.27 cents per Kilowatt-Hour

Competitive Transition Charge
- First 1,300 Kilowatt-Hours ..... 3.86 cents per Kilowatt-Hour
- Excess Kilowatt-Hours ..... 1.40 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 MTSD - MUNICIPAL TRAFFIC SIGNALS 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 ..... 1.84 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.

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 MTSD and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate MTSD 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 MTSD - MUNICIPAL TRAFFIC SIGNALS 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

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.

SPECIAL TERMS AND CONDITIONS

Energy usage shall be estimated by the Company on the basis of lamp wattage and burning-hours. The customer shall notify the Company whenever any change is made in the equipment or the burning-hours, so that the Company may revise the estimated energy usage.

RATE ALD - ARCHITECTURAL LIGHTING SERVICE DELIVERY

AVAILABILITY

Available for separately metered circuitry connected solely to outdoor architectural lighting equipment, with demand of 5 kilowatts or greater, to be operated during non-peak periods.

MONTHLY RATE

FIXED CHARGES

Customer Distribution Charge	$9.07
Competitive Transition Charge (CTC)	Customer Specific

DELIVERY CHARGES - DEMAND

Transmission Charge	$0.30 per Kilowatt
Distribution Charge	$1.88 per Kilowatt
Competitive Transition Charge	$1.33 per Kilowatt

DELIVERY CHARGES - ENERGY

Transmission Charge	
First 300 Kilowatt-Hours	0.27 cents per Kilowatt-Hour
Excess Kilowatt-Hours	0.08 cents per Kilowatt-Hour
Distribution Charge	
First 300 Kilowatt-Hours	1.72 cents per Kilowatt-Hour
Excess Kilowatt-Hours	0.51 cents per Kilowatt-Hour
Competitive Transition Charge	
First 300 Kilowatt-Hours	1.22 cents per Kilowatt-Hour
Excess Kilowatt-Hours	0.36 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 ALD - ARCHITECTURAL LIGHTING SERVICE 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..... 1.81 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 ALD - ARCHITECTURAL LIGHTING SERVICE 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 ALD and applicable riders in effect on December 31, 1998. The CTC will be equal to the annual revenue of Rate ALD 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.

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 may 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 or 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.

CONTRACT PROVISIONS

Contracts will be written for a period of not less than one year.

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 ALD - ARCHITECTURAL LIGHTING SERVICE DELIVERY - (Continued)

SPECIAL TERMS AND CONDITIONS

1. The service must supply only non-essential lighting facilities installed for decorative purposes and is not applicable to security lighting or the lighting of streets, highways, parking lots or athletic fields.

2. The lights must be controlled by a device that limits the equipment to operation during dusk to dawn hours only.

3. Responsibility for the provision and maintenance of all equipment used in the decorative lighting will remain with the customer.

4. In the event of a system emergency, the Company reserves the right to curtail the usage under this rate.

5. The Company reserves the right to require payment of connection and disconnection costs when a customer requests seasonal service under this rate.

STANDARD CONTRACT RIDERS

GENERAL

In addition to the standard service as set forth under the rates filed with this Tariff, the Company, where practicable, will render certain special classes of service where desired by the customer and provided that the customer meets the necessary requirements for such special service. A special agreement, additional and supplemental to the regular contract under which standard service is rendered, will be made with a customer for any of the special classes of service hereinafter indicated. The terms, conditions and other considerations for such special classes of service are set forth in the following Standard Contract Riders. Notwithstanding anything to the contrary in the said contract contained, the terms of a rider shall continue in force as long as the said contract remains valid. All terms in said contract, except as modified in the rider or riders applicable to it, shall be and remain in full force and effect.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 1 - DIRECT CURRENT SERVICE

(Applicable to Rates GS/GMD and GLD only)

Where customers have received direct current service continuously since February 1, 1928, the Company will render such service on this rider and bills will be computed in accordance with the following provisions:

Each customer receiving direct current service will be billed monthly for (1) a charge of $12.37 plus (2) a charge for delivery of Company supplied energy computed on the applicable rate schedule (either Rate GS/GMD or GLD), applying to the direct current system's metered kilowatt demand and kilowatt-hour consumption a kilowatt demand and a kilowatt-hour consumption based on the ratios of the customer's connected load and estimated consumption to the total of the connected loads and estimated consumptions of all direct current customers.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 2 - UNTRANSFORMED SERVICE

(Applicable to Rates GS/GMD, GMHD, GLHD, and GLD only)

Where customers take all or part of their electric delivery service directly from the Company's available primary distribution or transmission systems, and furnish all necessary equipment to take untransformed service, in strict accordance with the Company's standards and specifications, a monthly reduction based upon the individual demand of such circuit shall be allowed as follows:

First 50 Kilowatts at	20.3 cents per Kilowatt
Next 550 Kilowatts at	13.2 cents per Kilowatt
Excess over 600 Kilowatts at	7.1 cents per Kilowatt

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 3 - SCHOOL AND GOVERNMENTAL SERVICE DISCOUNT PERIOD

(Applicable to Rates GS/GMD, GMHD, GLHD, GLD and LD only)

For public or parochial schools, or local, state or federal governments or public agencies thereof, a Late Payment Charge specified in the applicable Rate GS/GMD, GMHD, GLHD, GLD or LD will be added to the net amount for failure to make payment of Company charges within thirty days from the mailing date.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 4 - BUDGET BILLING - HUD FINANCED MULTI-FAMILY HOUSING

(Applicable to Rates GS/GMD, GLD, GMHD, and GLHD only)

Budget billing for delivery service is available to master metered multi-family housing and/or the metered service for common areas and common facilities for multi-family housing during the time that such housing is either owned by the Federal Department of Housing and Urban Development or subject to a first mortgage held or guaranteed by that agency.

At the option of the customer, the Company will make an estimate subject to revisions when conditions warrant, of the total charge for the Company electric delivery service to be billed hereunder for a twelve-month period. A budget bill for approximately one-twelfth of such estimate will be rendered monthly. Any adjustment necessary in applying for the full period the actual charges herein established will be made on the final bill for the period. If the budget bill is unpaid when the next monthly bill is rendered, the budget arrangements for billing may be terminated by the Company.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 - TIME OF DAY DISCOUNTS

(Applicable to Rates GS/GMD, GLD, and LD - and to Rates GMHD *and GLHD during* months of June, July, August and September only)

Where a customer has a separately measured demand and is supplied by any standard service voltage and where such customer so operates that the maximum demand created during any billing period occurs during off-peak hours, the bills will be calculated using the Billing Demand defined below on the applicable rate and any other applicable riders.

Customers must contact under this rider prior to December 31, 1998 to qualify.

CONTRACT DEMANDS

The Contract On-Peak Demand is the maximum electrical capacity in kilowatts which the Company shall be required by the contract to make available during the on-peak hours to the customer.

The Contract Off-Peak Demand is the maximum electrical capacity in kilowatts which the Company shall be required by the contract to make available during the off-peak hours to the customer. The customer's minimum Billing Demand shall be no lower than one-third (33 1/3%) of the customer's Contract Off-Peak Demand.

The customer shall not establish a demand greater than 105 percent of the individual demands specified in the customer's contract unless written approval shall first have been obtained from the Company. If the customer establishes a repeated pattern of exceeding the Contract Demand, the Contract Demand may be raised to the highest demand established for the remaining term of the contract.

DEMANDS AND ENERGIES

The On-Peak Demand is the demand during on-peak hours. The Off-Peak Demand is the demand during *off-peak hours.*

The Billing Demand is the On-Peak Demand except where the Off-Peak Demand is more than three (3) times the On-Peak Demand. Then the Billing Demand will be one-third (33 1/3%) of the Off-Peak Demand. In no case will the Billing Demand be lower than the Billing Demand as determined on the applicable rate.

Demands and energies will be determined on an individual demand basis and corresponding quantities will be combined to obtain demands and energies for billing purposes.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 - TIME OF DAY DISCOUNTS - (Continued)

(Applicable to Rates GS/GMD, GLD, and LD - and to Rates GMHD and GLHD during months of June, July, August and September only)

ON-PEAK AND OFF-PEAK HOURS

The following hours will be designated as on-peak hours:

Monday through Thursday	Friday
10:00 A.M. TO 9:00 P.M.	10:00 A.M. TO 5:00 P.M.

ON-PEAK AND OFF-PEAK HOURS - (Continued)

The remaining hours including the generally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be designated as off-peak hours. The Company may, upon written notice to customers taking service under this rider and upon filing same with the Pennsylvania Public Utility Commission, make such changes in the on-peak hours as it may from time to time deem necessary.

METER CHARGE

For customers with maximum Contract Demands between 500 and 1,000 kW which apply for service on Rider No. 5, the following meter charges will be added to the customer's monthly bill for each metered service voltage supplied to the customer:

For service applied for prior to January 1, 1982 ..... $17.00 per month
For service applied for after January 1, 1982..... $33.00 per month

For customers with maximum Contract Demands between 5 and 499 kilowatts which apply for service on Rider No. 5, a meter charge of $10.00 per month will be added to the customer's monthly bill for each metered service voltage supplied to the customer.

For customers on Rates GMHD and GLHD, the appropriate meter charge will be added to all twelve monthly bills. The meter charge and type of meter for GMHD and GLHD customers will be determined by the maximum demand.

CONTRACT PROVISIONS

For customers with Contract On-Peak Demands exceeding 500 kW, contracts will be written for a period not less than two years.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 6 - TEMPORARY SERVICE

(Applicable to Rate GS/GMD only)

Where a customer desires service of a temporary nature for periods of less than 30 days, the Company will:

1. Charge in advance for the estimated cost of installing and removing the necessary facilities to furnish such service.

2. Estimate the demand and the consumption requirements from the connected load and the number of days during which Company electric service is to be used, but in no case less than six (6) days.

3. Estimate the delivery and energy charges in accordance with the provisions of the applicable rate.

4. Require the customer to make a deposit in the amount of the estimated delivery and energy charges under the applicable rate.

5. Refund said deposit less the amount of the bill due the Company upon surrender of the deposit receipt by the customer.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 7 - INTERRUPTIBLE SERVICE

(Applicable to Rates GLD, GLHD, and LD)

Available for completely or partially interruptible power service at not less than 23,000 volts at points of supply designated by the Company with the minimum contracted interruptible load of not less than 500 kW.

Where a customer contracts for interruptible loads of not less than 500 kW and agrees to the "Special Terms and Conditions" listed below, the Capacity Charge of the General Service Rate under which the customer received electrical service will be reduced by a $2.03 credit per kW of contracted interruptible load.

Customers must contract under this rider prior to December 31, 1998 and must take full service from the Company as defined in the applicable rate schedules to qualify.

CONTRACT TERM

Contracts shall be written for an original term of not less than three years and such contracts shall continue in force after the expiration of the original term until one year following the date of written notice of cancellation by either party when this rider is applied to General Service Rate GLD.

When this rider is applied to Rate LD - Large Power Delivery Service, the length of the contract shall be the same as contained in the Rate LD contract.

The Company reserves the right to refuse firm power capacity to replace the interruptible portion of the customer's load, if in its judgment its generating or transmission capacity is no more than adequate to meet the requirements of its firm power load of its existing customers.

METER CHARGE

For customers with an Interruptible Demand of 500 kW or more which apply for service on Rider No. 7, the customer will be charged Duquesne's incremental metering costs for monitoring the interruptible load. In addition, a monthly meter charge of $12.00 will also be required if the customer does not already have a recording magnetic tape meter with a spare channel to monitor the interruptible load.

INTERRUPTIBLE LOAD CONTROL SYSTEM CHARGE

In order to interrupt the customer's interruptible equipment from a central location, a transmitter-multiple receiver arrangement must be installed. Duquesne will own, operate, and maintain this equipment. However, all costs associated with this installation will be recovered from the group of customers accepting the interruptible rate through a one-time installation fee which will be determined based on the number of customers accepting the rate.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 7 - INTERRUPTIBLE SERVICE - (Continued)

(Applicable to Rates GLD, GLHD, and LD)

SPECIAL TERMS AND CONDITIONS

To be eligible for this rider the customer must agree to the following terms and conditions:

1. The Company must have unilateral, irrevocable control of the customer's equipment used to disconnect the interruptible load from its electric supply. The irrevocable control of the customer's equipment used to disconnect the interruptible load applies to the period of the interruption.

2. The system would be designed to provide a warning to the customer of imminent interruptions. However, Duquesne Light would reserve the right to interrupt service to the interruptible load at any time without advance notice to the customer. Subject to this reservation, the Company will endeavor to make available to the customer capacity equal to the demand specified in the contract for at least 80% of the hours in any calendar month and 90% of the hours in any calendar year. In all cases it is the customer's responsibility to restore the load following notification from Duquesne that the interruption period is over.

3. The Company shall not be liable for any loss, cost, damage or expense to customer caused by the disconnection of contracted-for interruptible load from its electric supply.

4. The minimum amount of interruptible load would be 500 kW.

5. Interruptible service would be available as either complete or partial interruptible power service at not less than 23,000 volts. In certain special instances interruptible service will be available from the 11,500 volt network system.

6. The interruptible portion must be load from facilities that the customer utilizes on a regular basis between 8 a.m. and 10 p.m. on each day throughout the year except Saturdays, Sundays, and generally observed holidays. If the customer ceases to utilize such facilities for more than 60 days, the customer must notify the Company.

7. Customers will be responsible for installing breakers, an interfacing relay, and for making any necessary wiring, structural or equipment location changes to allow isolation of the interruptible portion of the load without affecting the remainder of the service.

8. The Company will install, own (or control the lease), and maintain the transmitter, communication channel, receiver and relaying equipment utilized to operate the customer-owned and installed and customer-maintained circuit breaker utilized to interrupt the interruptible load. The Company will install appropriate monitoring equipment on the interruptible service or circuit breaker to enable the Company to determine at a later date that the interruptible load was interrupted. The customer is responsible for the safety and proper operation of the customer's circuit breaker and associated equipment.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 7 - INTERRUPTIBLE SERVICE - (Continued)

(Applicable to Rates GLD, GLHD, and LD)

SPECIAL TERMS AND CONDITIONS - (Continued)

9. Interruptible load will be interrupted as a result of overloads on the transmission, subtransmission and distribution systems on exactly the same basis as firm load customers are interrupted.

10. Where the customer's entire load is under a load management device, the customer must make provisions so that the load management device does not recognize the loss of the interruptible load.

11. The amount of interruptible load that is available will be determined solely by the Company and will be contracted for on a first-come, first-served basis.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 - INDUSTRIAL ECONOMIC DEVELOPMENT
RIDER FOR CUSTOMERS AT EXISTING SERVICE LOCATIONS

(Applicable to Rates GMD, GLD and LD)

PURPOSE

Stimulating industrial production in Duquesne's economically distressed service area can produce benefits in terms of job creation, increased regional income, and improved living standards. The purpose of this rider is to encourage load management, increased regional industrial production, and growth in employment through an incentive for industrial customers at Existing Service Locations.

AVAILABILITY

This rider will be available for a period not exceeding five (5) years to each qualifying customer having a Monthly Base Period Billing Demand of 100 kilowatts or greater. Qualifying definitions, rules, and conditions are listed below.

Customers must contract under this rider prior to December 31, 1998 to qualify.

ECONOMIC INCENTIVES

A qualifying customer will earn a separately stated credit equal to the Billing Demand minus the Monthly Base Period Billing Demand multiplied by the discounted Incremental Unit Capacity Charge of the applicable rate. The percentage discount is determined as follows:

	Percent Discount to Incremental Unit Capacity Charge		
Incremental Hours Use	First 36 Months On Rider	Next 12 Months On Rider	Next 12 Months On Rider
Over 350 Hours use	50	30	15
Over 300 to 350 Hours Use	40	24	12
Over 250 to 300 Hours Use	30	18	9
Over 200 to 250 Hours Use	20	12	6
Over 150 to 200 Hours Use	10	6	2
150 Hours Use or Less	0	0	0

where the current Billing Demand exceeds the Monthly Base Period Billing Demand by five percent (5%) or more with a minimum of 25 kilowatts.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER FOR CUSTOMERS AT EXISTING SERVICE LOCATIONS - (Continued)

(Applicable to Rates GMD, GLD and LD)

ECONOMIC INCENTIVES - (Continued)

A qualifying customer will also earn a separately stated credit equal to the kilowatt-hours minus the Monthly Base Period Kilowatt-hours multiplied by the discounted Incremental Unit Energy Charge of the applicable rate, excluding the energy billed at the excess kilowatt-hour charges of Rate LD. The percentage discount is determined as follows:

	Percent Discount to Incremental Unit Energy Charge		
Incremental Hours Use	First 36 Months On Rider	Next 12 Months On Rider	Next 12 Months On Rider
Over 350 Hours use	25	15	7.5
Over 300 to 350 Hours Use	20	12	6
Over 250 to 300 Hours Use	15	9	4.5
Over 200 to 250 Hours Use	10	6	3
Over 150 to 200 Hours Use	5	3	1.5
150 Hours Use or Less	0	0	0

The percent discount applicable to those Incremental kilowatt-hours to be billed at the excess kilowatt-hour charges of Rate LD will be 15% for the first three (3) years, 9% for the fourth year, and 4.5% for the fifth year.

NOTE

Except for the provisions specifically set forth in this rider, all provisions, prices, and regulations of the standard service rate under which the customer receives service shall apply.

The above credits will be applied before application of Rider No. 10 - State Tax Adjustment. All applicable "Standard Contract Riders" will remain in effect; however, the discounted Incremental Unit Capacity Charge applicable to a customer's billing shall not be less than twenty-five percent (25%) of the nondiscounted Incremental Unit Capacity Charge expressed in the applicable rate. The Minimum Charge Provision of the applicable rate shall not be reduced by this rider.

STANDARD CONTRACT *RIDERS - (Continued)*

RIDER NO. 8 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER
FOR CUSTOMERS AT EXISTING SERVICE LOCATIONS - (Continued)

(Applicable to Rates GMD, GLD and LD)

DEFINITIONS

1. **Incremental Hours Use**

$$\frac{\text{(Total Kilowatt-hours used in billing period - Monthly Base Period Usage)}}{\text{(Billing Demand - Monthly Base Period Billing Demand)}}$$

2. ***Existing Service Location*** - An existing location of a customer having one or more delivery points for electric service billed separately by the Company under a single billing address.

3. **Base Period** - The twelve consecutive monthly billing periods applicable to the customer ending one month prior to the application of the rider.

4. **Monthly Base Period Billing Demand** - The Billing Demand used in billing the Existing Service Location for the month in the Base Period corresponding to the billing month to which the rate reduction under this rider is applied.

5. **Monthly Base Period Usage** - The total kilowatt-hour usage of the customer used in billing the Existing Service Location for the month in the Base Period corresponding to the billing month to which the rate reduction under this rider is applied.

6. **Incremental Unit Capacity Charge** - The appropriate $ per kilowatt charge(s) as stated in the Capacity Charge provision of the currently effective general service rate that applies to each kilowatt of Billing Demand greater than the Monthly Base Period Billing Demand.

7. **Incremental Unit Energy Charge** - The applicable ¢ per kilowatt-hour shall be the excess kilowatt-hour charge of Rate GMD, kilowatt-hour charge of Rate GLD, and charge for 750,000 kilowatt-hours plus 400 kilowatt-hours per kilowatt of demand of Rate LD of the currently effective rates. The excess kilowatt-hour charges of Rate LD shall be discounted at the specified percentages.

8. **Employment Reports** - "Employer's Report for Unemployment Compensation" and "Employer's Quarterly Report of Wages Paid to Each Employee" as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania, and the "Employer's Quarterly Employment and Wage Analysis" as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania for employers who have more than one place of business in the Commonwealth.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER FOR CUSTOMERS AT EXISTING SERVICE LOCATIONS - (Continued)

(Applicable to Rates GMD, GLD and LD)

RULES

1. **Existing Service Locations** - If an existing customer in the service area moves their operation to a new location, the Base Period of the prior service shall move with the customer, and the new location would be treated as an Existing Service Location. A service location, to which the Company had previously supplied service within the prior twelve (12) months for substantially the same industrial manufacturing or processing as the present or proposed operation, would be treated as an Existing Service Location. However, the Base Period would be then defined as the last twelve (12) monthly billing periods during which there was industrial operation at the site.

2. **Monthly Base Period Billing Demand** - If the existing customer did not receive service during the entire Base Period, the Monthly Base Period Billing Demand shall be determined by the Company.

3. **Monthly Base Period Usage** - The Company reserves the right to adjust the Monthly Base Period Usage for unusual circumstances such as labor work stoppages. If the existing customer did not receive service during the entire Base Period, the Monthly Base Period Usage shall be determined by the Company.

QUALIFYING CONDITIONS

1. The customer must have an Existing Service Location.

2. The customer must be engaged in manufacturing or processing operation as defined in the Division D. Manufacturing Standard Industrial Classification (SIC) categories as described in the 1972 Edition of Standard Industrial Classification Manual, supplements thereto, or the latest edition.

3. A Pennsylvania Sales Tax Blanket Exemption Certificate must be filed by the customer with the Company showing the address of the service location to which the rider is to be applicable and certifying that more than fifty percent (50%) (on an annual basis) of the electricity purchased thereunder is exempt from sales tax because it is used in manufacturing or processing operations.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER FOR CUSTOMERS AT EXISTING SERVICE LOCATIONS - (Continued)

(Applicable to Rates GMD, GLD and LD)

QUALIFYING CONDITIONS - (Continued)

4. Employment Reports must be filed with the Company for the Base Period prior to application of the rider and no later than thirty days after the end of the reporting quarter as defined by 43 P.S. 753d.

5. The customer at the Existing Service Location must have expanded its load requirement by five percent (5%) or more above the Monthly Base Period Billing Demand.

6. The Contract Demand specified in the customer's existing service contract at the time of the customer's application of the rider shall be used in determination of Minimum Charge. The Monthly Base Period Billing Demand will not be affected by a revision of the customer's Contract Demand during the Base Period.

7. The customer must sign an "Economic Development Rider No. 8 Amendment To Electric Service Contract" with the Company for the required term of the rider. Modification of the contract may result in the cancellation of this rider.

8. A service location is eligible for the rider only one time.

9. The Company reserves the right to refuse this rider to customers who do not meet the conditions specified above.

GENERAL QUALIFYING CONDITIONS

1. The application of the rider will be discontinued if bills are not paid when due as specified in Tariff Rule No. 21, before the addition of a Late Payment Charge.

2. The rider will be reserved for a customer who applied to the Company for the rider in writing up to twelve months prior to the time service is required.

3. Discontinuance of or detrimental changes to the rider will not apply to an existing rider participant or a prospective participant as described to General Qualifying Condition (2).

4. The Company will monitor the impact of the rider and may modify or discontinue the provisions at any time as approved by the Pennsylvania Public Utility Commission except for the limitations established in General Qualifying Condition (3).

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER FOR CUSTOMERS AT EXISTING SERVICE LOCATIONS - (Continued)

(Applicable to Rates GMD, GLD and LD)

SPECIAL PROVISION FOR RATE LD

For those existing Rate LD customers who do not qualify for the Economic Incentives provided by this rider, but do satisfy Qualifying Condition (2), a separate credit applicable to increased kilowatt-hours is available. A customer who anticipates an increase of ten percent (10%) or more in kilowatt-hour use over the kilowatt-hour use in the Base Period must sign an "Economic Development Rider No. 8 Amendment to Electric Service Contract". In those months where the increased kilowatt-hours are ten percent (10%) or more than the Base Period Kilowatt-hours, a customer will earn a credit equal to the increased kilowatt-hours multiplied by the discounted Incremental Unit Energy Charge. The percent discount applicable will be twenty-five (25%) for the first three (3) years, fifteen percent (15%) in the fourth year, and 7.5% in the fifth year, except for the excess kilowatt-hour charges of Rate LD which is specified under Rate LD Exception.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER FOR CUSTOMERS AT NEW SERVICE LOCATIONS

(Applicable to Rates GMD, GLD, and LD)

PURPOSE

Stimulating industrial production in Duquesne's economically distressed service area can produce benefits in terms of job creation, increased regional income, and improved living standards. The purpose of this rider is to encourage load management, increased regional industrial production, and growth in employment through an incentive for industrial customers at New Service Locations.

AVAILABILITY

This rider will be available for a period not exceeding five (5) years to each qualifying customer having an anticipated average annual load requirement of 100 kilowatts or greater. Qualifying definitions and conditions are listed below.

ECONOMIC INCENTIVE

A qualifying customer will earn a separately stated credit equal to the percentage discount determined below multiplied by the monthly total Capacity delivery Charge of the applicable rate. The percentage discount is determined as follows:

	Percent Discount to Incremental Unit Capacity Charge		
Incremental Hours Use	First 36 Months On Rider	Next 12 Months On Rider	Next 12 Months On Rider
Over 350 Hours use	50	30	15
Over 300 to 350 Hours Use	40	24	12
Over 250 to 300 Hours Use	30	18	9
Over 200 to 250 Hours Use	20	12	6
Over 150 to 200 Hours Use	10	6	2
150 Hours Use or Less	0	0	0

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER
FOR CUSTOMERS AT NEW SERVICE LOCATIONS - (Continued)

(Applicable to Rates GMD, GLD, and LD)

ECONOMIC INCENTIVE - (Continued)

A qualifying customer will earn a separately stated credit equal to the percentage discount determined below multiplied by the monthly Energy delivery Charges, and any Duquesne energy supply charges of the applicable rate excluding the energy billed at the excess kilowatt-hour charges of Rate LD. The percentage discount is determined as follows:

	Percent Discount to Incremental Unit Energy Charge		
Incremental Hours Use	First 36 Months On Rider	Next 12 Months On Rider	Next 12 Months On Rider
Over 350 Hours use	25	15	7.5
Over 300 to 350 Hours Use	20	12	6
Over 250 to 300 Hours Use	15	9	4.5
Over 200 to 250 Hours Use	10	6	3
Over 150 to 200 Hours Use	5	3	1.5
150 Hours Use or Less	0	0	0

The percent discount applicable to those kilowatt-hours to be billed at the excess kilowatt-hour delivery charges of Rate LD will be 15% for the first three (3) years, 9% for the fourth year, and 4.5% for the fifth year.

NOTE

Except for the provisions specifically set forth in this rider, all provisions, prices, and regulations of the standard general service rate under which the customer receives service shall apply.

The preceding credits will be applied before application of Rider No. 10 - State Tax Adjustment. All applicable "Standard Contract Riders" will remain in effect; however, the discounted Capacity Charge applicable to a customer's billing shall not be less than twenty-five percent (25%) of the nondiscounted Capacity Charge expressed in the applicable rate. The Minimum Charge Provision of the appropriate general service rate shall not be reduced by this rider.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER FOR CUSTOMERS AT NEW SERVICE LOCATIONS - (Continued

(Applicable to Rates GMD, GLD, and LD)

DEFINITIONS

1. **Hours Use** -

$$\frac{\text{Total Kilowatt-hours used in billing period}}{\text{Billing Demand}}$$

2. **New Service Location** - A location having one or more delivery points for electric service which will be billed separately by the Company under a single billing address:

   (a) To which the Company has not previously supplied electric service

   or

   (b) To which the Company has previously supplied electric service provided that the service previously supplied had not been used for substantially the same industrial manufacturing or processing as the present operation or that its industrial use had been discontinued at least twelve (12) months prior to application for service under this rider.

3. **Employment Reports** - The "Employer's Report for Unemployment Compensation" and "Employer's Quarterly Report of Wages Paid to Each Employee" as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania and the "Employer's Quarterly Employment and Wage Analysis" is filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania for employers who have more than one place of business in the Commonwealth.

QUALIFYING CONDITIONS

1. The customer must be one moving into a New Service Location.

2. The customer must be engaged in manufacturing or processing operation as defined in the Division D. Manufacturing Standard Industrial Classification (SIC) categories as described in the 1972 Edition of Standard Industrial Classification Manual, supplements thereto, or later editions.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 - INDUSTRIAL ECONOMIC DEVELOPMENT RIDER
FOR CUSTOMERS AT NEW SERVICE LOCATIONS - (Continued)

(Applicable to Rates GMD, GLD, and LD)

QUALIFYING CONDITIONS - (Continued)

3. A Pennsylvania Sales Tax Blanket Exemption Certificate must be filed by the customer with the Company as soon as it is filed with the Commonwealth showing the address of the service location to which the rider is to be applicable and certifying that more than fifty percent (50%) (on an annual basis) of the electricity purchased thereunder is exempt from sales tax because it is used in manufacturing or processing operations. The rider shall not be effective until the Certificate or other suitable evidence acceptable to the Company is filed with the Company assuring that the above usage criteria is being achieved.

4. Current "Employment Reports", as defined, must be filed with the Company no later than thirty days after the end of the reporting quarter as defined at 43 P.S. 753d.

5. The customer must sign an "Economic Development Rider No. 9 Amendment to Electric Service Contract". Modifications of the contract may result in the cancellation of this rider.

6. A service location is eligible for the rider only one time.

7. The Company reserves the right to refuse this rider to customers who do not meet the conditions specified above.

GENERAL QUALIFYING CONDITIONS

1. The application of the rider will be discontinued if bills are not paid when due as specified in Tariff Rule No. 21, before the addition of a Late Payment Charge.

2. The rider will be reserved for a customer who applies to the Company for the rider in writing up to twelve months prior to the time service is required.

3. Discontinuance of or detrimental changes to the rider will not apply to an existing rider participant or a prospective participant as described in General Qualifying Condition (2).

4. The Company will monitor the impact of the rider and modify or discontinue the provisions anytime as approved by the Pennsylvania Public Utility Commission, except for the limitations established in General Qualifying Condition (3).

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 10 - STATE TAX ADJUSTMENT

(Applicable to All Rates)

In addition to the charges provided in this Tariff, a surcharge of 0% will apply to the delivery portion of all bills, pursuant to the Pennsylvania Public Utility Commission authorization of March 10, 1970, to compensate the Company for new and increased taxes imposed by the General Assembly.

The Company will recompute the surcharge using the elements prescribed by the Commission's March 10, 1970, authorization:

1. Whenever any of the tax rates used in computing the surcharge is changed, in which case the recomputation shall take into account the changed tax rate.

2. Whenever the Company makes effective increased or decreased rates (other than net energy clause), in which case the recomputation shall take into account the adjustments prescribed by the Commission's March 10, 1970, authorization.

3. On March 31, 1971, and each year thereafter.

Every recomputation made pursuant to the above paragraph shall be submitted to the Commission within ten (10) days after the occurrence of the event or date which occasions such recomputation: and if the recomputed surcharge is less than the one then in effect the Company will, and if the recomputed surcharge is more than the one then in effect the Company may, accompany such recomputation with a Tariff or supplement to reflect such recomputed surcharge, the effective date of which, shall be ten (10) days after filing.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 11 - STREET RAILWAY SERVICE

(Applicable to Rates GS/GMD and GLD Only)

Where service is supplied at 11,500 volts or higher at two or more interconnected points of delivery to any street railway system for the purpose of conversion to direct current energy for the operation of such system, the Billing Demand in kilowatts of such service shall be reduced by seven percent (7%) for the purpose of computation of the delivery charges of the bill under Rates GS/GMD and GLD and any other applicable rider.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 12 - BILLING OPTION FOR VOLUNTEER FIRE COMPANIES AND NONPROFIT SENIOR CITIZEN CENTERS

(Applicable to Rates GS/GMD, and GMHD only)

Upon application, Pursuant to Act 103 of 1985, a Volunteer Fire Company or a Nonprofit Senior Citizen Center may elect to have its electric service billed at the pricing of RATE RSD - RESIDENTIAL SERVICE or of RATE RHD - RESIDENTIAL SERVICE HEATING provided that it satisfies the space heating requirements stated in the availability clause of Rate RHD.

Contracts will be for a period of not less than one (1) year.

DEFINITIONS

VOLUNTEER FIRE COMPANY - A *separately metered service* location consisting of a building, sirens, a garage for housing vehicular fire fighting equipment, or a facility certified by the Pennsylvania Emergency Management Agency (PEMA) for fire fighter training. The sole use of electric service at this service location shall be to support the activities of the volunteer fire company. Any fund raising activities at this service location must be used solely to support volunteer fire fighting operations.

The customer of record at this service location must be a predominately volunteer fire company recognized by the local municipality or PEMA as a provider of fire fighting services.

NONPROFIT SENIOR CITIZEN CENTER - A separately metered service location consisting of a facility for the sole use of senior citizens coming together as individuals or groups and where access to a wide range of services to senior citizens is provided.

The customer of record at this service location must be an organization recognized by the Internal Revenue Service (IRS) as nonprofit and recognized by the Department of Aging as an operator of a senior citizen center.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - SERVICE TO NON-UTILITY GENERATING FACILITIES

(Applicable to all General Service Rates)

The following applies to non-utility generating facilities including, but not limited to cogeneration and small power production facilities which are qualified in accord with Part 292 of Chapter I, Title 18, Code of Federal Regulations (qualifying facility). Electric energy will be supplied to a non-utility generating facility in accord with the following:

A. **Supplementary Power** is electric energy supplied by Duquesne Light to a non-utility generating facility and regularly used in addition to that electric energy which the non-utility generating facility generates itself.

Duquesne Light's regular and appropriate General Service Delivery Rates will be utilized for billing for Supplementary Power.

B. **Firm Back-Up Power** is electric energy supplied by Duquesne Light to a non-utility generating facility during an unscheduled outage of the non-utility generating facility's electric generating equipment to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment.

The Company will supply such service each month at the following rates:

LD/HVPSD (5,000 kW or more)	$3.58/kW	Energy @ 3.16 cents/kWh
GLD (300 to 4,999 kW)	$4.90/kW	Energy @ 3.09 cents/kWh
GS/GMD (less than 300 kW)	$5.61/kW	Energy @ 3.83 cents/kWh

Plus for any General Service Large Delivery (300 to 4,999 kilowatts) or Small/Medium Delivery (less than 300 kilowatts) customer commencing service under Rider No. 16 after January 16, 1996, the following charges to recover the cost of existing or newly required transformation equipment that is over and above that equipment necessary for Duquesne Light to supply the customer with its contracted Supplemental Power will apply:

General Service Large Delivery (300 to 4,999 kW)	$0.25/kW
General Service Small/Medium Delivery (less than 300 kW)	$0.37/kW

(The monthly per kW charge for transformation equipment for Large Power Service Delivery/HVPSD [5,000 kilowatts and over] customers will be determined by Duquesne Light on a case-by-case basis.)

However, any Large Power Service Delivery/HVPSD, General Service Large Delivery or General Service Small/Medium Delivery customer electing to pay the total costs of such transformation at the onset of its contract may do so pursuant to Section E and will not subsequently be billed the aforementioned monthly per kW charges.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

B. (Continued)

During any month in which the Company is not required to provide energy to backup the customer's source of power, the customer will pay the above charges for contracted backup capacity.

The use of firm backup power at this price level will be limited to 15% usage for all hours in a year. Incremental usage above this limit will be billed on the applicable general service rates, including all ratchets applicable.

If a customer's actual kW demand at the time back-up is being supplied exceeds the customer's firm back-up Contract Demand by 5% or more, the actual kW demand as established will become the customer's new firm back-up Contract Demand for the remaining term of the firm back-up contract. If a customer's actual kW demand at the time back-up service is being supplied exceeds the customer's firm back-up Contract Demand by 10% or more, the customer will be assessed a fee determined by the difference between the actual demand established when back-up service is being supplied and the firm back-up Contract Demand multiplied by two times the applicable charge per kilowatt.

C. **Interruptible Back-up Power** is electric energy supplied by Duquesne Light to a non-utility generating facility during an unscheduled outage of the non-utility generating facility's electric generating equipment to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment, subject to interruption by the Company.

The Company will provide interruptible backup service to those customers with at least 500 kW of interruptible load. The Company reserves the right to interrupt service to the customer with a 30 minute notice period during periods of transmission limitation or peak period where service to the customer will result in the need for additional capacity sources to be acquired. The rates for such service shall be the following:

LD/HVPSD (5,000 kW or more)	$2.28/kW	Energy @ 3.16 cents/kWh
GLD (300 to 4,999 kW)	$3.44/kW	Energy @ 3.09 cents/kWh
GS/GMD (less than 300 kW)	$4.29/kW	Energy @ 3.83 cents/kWh

These charges will be paid every month regardless of whether or not the Company is required to provide energy to backup the customer's equipment.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

C. (Continued)

Plus for any General Service Large Delivery (300 to 4,999 kilowatts) or Small/Medium Delivery (less than 300 kilowatts) customer commencing service under Rider No. 16 after January 16, 1996, the following charges to recover the cost of existing or newly required transformation equipment that is over and above that equipment necessary for Duquesne Light to supply the customer with its contracted Supplemental Power will apply:

General Service Large Delivery (300 to 4,999 kW) $0.28/kW
General Service Small/Medium Delivery (less than 300 kW) $0.42/kW

(The monthly per kW charge for transformation equipment for Large Power ServiceDelivery/HVPSD [5,000 kilowatts and over] customers will be determined by Duquesne Light on a case-by-case basis.)

However, any Large Power Service Delivery/HVPSD, General Service Large Delivery or General Service Small/Medium Delivery customer electing to pay the total costs of such transformation at the onset of its contract may do so pursuant to Section E and will not subsequently be billed the aforementioned monthly per kW charges.

The use of interruptible backup power at this price level will be limited to 15% usage for all hours in a year. Incremental usage above this limit will be billed on the applicable general service rates, including all ratchets applicable.

If a customer's actual kW demand at the time back-up is being supplied exceeds the customer's interruptible back-up Contract Demand by 5% or more, the actual kW demand as established will become the customer's new interruptible back-up Contract Demand for the remaining term of the interruptible back-up contract. If a customer's actual kW demand at the time back-up service is being supplied exceeds the customer's interruptible back-up Contract Demand by 10% or more, the customer will be assessed a fee determined by the difference between the actual demand established when back-up service is being supplied and the interruptible back-up Contract Demand multiplied by two times the applicable charge per kilowatt.

D. **Maintenance Power** is electric energy supplied by Duquesne Light to a non-utility generating facility during outages for maintenance of the non-utility generating facility's electric generating equipment which are scheduled by the non-utility generating facility at a time mutually agreeable with Duquesne Light.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

D. (Continued)

The following terms and conditions apply to all customers utilizing maintenance power:

Any customer who contracts for either firm or interruptible backup power will pay only the maintenance energy charges, that are 3 mills/kWh less than the backup energy rates, for their maintenance service. However, for those customers who take maintenance service in excess of contracted demands of firm and/or interruptible backup power, the maintenance demand charges will also apply. Customers contracting for maintenance service only will pay the maintenance service demand and backup power energy charges.

LD/HVPSD (5,000 kW or more)	$2.28/kW	Energy @ 2.86 cents/kWh
GLD (300 to 4,999 kW)	$3.44/kW	Energy @ 2.79 cents/kWh
GS/GMD (less than 300 kW)	$4.29/kW	Energy @ 3.53 cents/kWh

Plus for any General Service Large Delivery (300 to 4,999 kilowatts) or Small/Medium Delivery (less than 300 kilowatts) customer commencing service under Rider No. 16 after January 16, 1996, the following charges to recover the cost of existing or newly required transformation equipment that is over and above that equipment necessary for Duquesne Light to supply the customer with its contracted Supplemental Power will apply:

General Service Large Delivery (300 to 4,999 kW)	$0.28/kW
General Service Small/Medium Delivery (less than 300 kW)	$0.42/kW

(The monthly per kW charge for transformation equipment for Large Power Service Delivery/HVPSD [5,000 kilowatts and over] customers will be determined by Duquesne Light on a case-by-case basis.)

However, any Large Power Service Delivery/HVPSD, General Service Large Delivery or General Service Small/Medium Delivery customer electing to pay the total costs of such transformation at the onset of its contract may do so pursuant to Section E and will not subsequently be billed the aforementioned monthly per kW charges.

These charges for maintenance service will be paid only in months of actual usage.

The customer shall specify to the Company the amount of maintenance power required.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

D. - (Continued)

Beginning with the date upon which the non-utility generating facility's generating equipment is first operated in any manner whatsoever, and during the immediately ensuing three (3) months of operation of the non-utility generating facility's generating equipment, maintenance power will be supplied by Duquesne Light, if available in the sole judgment of Duquesne Light, to the non-utility generating facility at the non-utility generating facility's request, in order to permit the non-utility generating facility to "shake down" the generating equipment.

After the three-month "shake down" period, the non-utility generating facility will provide the following notice to Duquesne Light for the need for maintenance power:

(1) For a non-utility generating facility requesting less than 15 mW of maintenance power, the non-utility generating facility will provide 30 calendar days notice to Duquesne Light of the need for maintenance power. Duquesne Light will respond within seven (7) calendar days of notification by the non-utility generating facility whether or not maintenance power can be made available at the time requested or at some other time.

(2) For a non-utility generating facility requesting between 15 mW and 30 mW of maintenance power, the non-utility generating facility will provide 60 calendar days notice to Duquesne Light of the need for maintenance power. Duquesne Light will respond within 14 calendar days of the notification by the non-utility generating facility whether or not maintenance power can be made available at the time requested or at some other time.

(3) For a non-utility generating facility requesting more than 30 mW of maintenance power, the non-utility generating facility will provide 90 calendar days notice to Duquesne Light of the need for maintenance power. Duquesne Light will respond within 21 calendar days of the notification by the non-utility generating facility whether or not maintenance power can be made available at the time requested or at some other time.

The Company will make available the maintenance power upon mutual agreement within 30 days before or after the customer's requested scheduled maintenance outage date.

Maintenance power will be available to a non-utility generating facility not more than five (5) separate periods in a calendar year, cumulatively totaling 60 days in a calendar year.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to all General Service Rates)

D. - (Continued)

Maintenance power may be available between the hours of 10:00 p.m. and 8:00 a.m. weekdays and all day Saturdays, Sundays and generally observed holidays upon six (6) hours notice to Duquesne Light by the non-utility generating facility. These limited "off-peak" uses of maintenance power will be restricted to not more than 15 separate periods in a calendar year and will not be included in the five (5) separate periods or 30 days in a calendar year. The availability of maintenance power between the hours of 10:00 p.m. and 8:00 a.m. weekdays and all day Saturdays, Sundays and generally observed Holidays would be determined solely by Duquesne Light and Duquesne Light will respond within two (2) hours of the request for maintenance power by the non-utility generating facility.

E. Each non-utility generating facility will be required to install at its expense or pay in advance to have Duquesne Light install interconnection equipment and facilities which are over and above that equipment and facilities required to provide electric service to the non-utility generating facility according to Duquesne Light's General Service Rates. (The costs of transformation equipment recovered under Sections B, C and D on a per kW monthly basis from Large Power Service Delivery/HVPSD, General Service Large Delivery and General Service Small/Medium Delivery customers *are not* included herein.) Any such equipment to be installed by the non-utility generating facility must be reviewed and approved in writing by Duquesne Light prior to installation. Nothing in this rider shall exempt a new customer from the application of Rules No. 7 and 9 regarding Supply Line Extensions and Relocation of Facilities.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 14 - EMERGENCY ENERGY CONSERVATION

(Applicable to Rates GLD, GLHD, LD, and HVPSD only)

PURPOSE

This rider is applicable in conjunction with Tariff Rule 39.2, relating to Emergency Energy Conservation. It provides for deviation from and modifications to the charges and practices otherwise applicable to certain customers as a result of compliance with or noncompliance with energy conservation curtailment levels requested or ordered under emergency energy conservation conditions resulting from actual or potential shortage of fuel for electric generation.

APPLICABILITY

Applicable progressively in the following order of priority as required by the need for curtailment to meet conditions resulting from actual or potential shortage of fuel for electric generation:

1. To individual electric customer accounts served under Rates LD and HVPSD with recorded demand of 5,000 kW or higher in a recent 12-month period prior to the request of or order for emergency energy conservation.

2. To individual electric customer accounts served under Rates GLD and GLHD with recorded demand of 300 kW or higher in a recent 12-month period prior to the request of or order for emergency energy conservation.

Customers designated as exempt in the procedures for emergency energy conservation filed in accord with Tariff Rule 39.2 or by the Pennsylvania Public Utility Commission will be exempt from the provisions of this rider.

DEFINITIONS

1. **Base Period Energy Use** - The base energy use for a weekly period shall be determined by the Company for each applicable electric customer account based upon a consideration of the customer's actual past or current electric consumption and the customer's existing operation.

2. **Mandatory Curtailment Energy Use Level Target** - The Mandatory Curtailment Energy Use Level Target for each applicable customer shall be that percentage of base period energy use ordered pursuant to the emergency energy conservation procedures provided by Tariff Rule 39.2 or other percentage as a result of the order of appropriate governmental authority.

3. **Current Energy Use** - Current period use will be monitored on a weekly basis commencing on the date the emergency is declared.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 14 - EMERGENCY ENERGY CONSERVATION - (Continued)

(Applicable to Rates GLD, GLHD, LD, and HVPSD only)

DEFINITIONS - (Continued)

4. **Compliance** - When the energy consumption in any weekly period during the period of the mandatory emergency energy conservation condition is equal to or less than the mandatory curtailment energy use level target, the customer will be deemed to have complied.

   In the event of continued non-compliance, the Company, upon notice to the Commission, may discontinue service.

   A customer may arrange with the utility for mutually acceptable methods for achieving the mandatory curtailment energy use level target, as long as the customer, in total, meets the curtailment target.

BILLING

During the period of emergency energy conservation condition, billing will be based on meter readings especially made to identify the demand established and energy used during the current energy use period. Customers in compliance with conservation orders will be excused from minimum bills and historical or Contract Demand or ratchet provisions and will be billed instead on the basis of current consumption and demand whenever the normal calculation method would produce a greater bill.

These customers will be individually notified of this special billing provision prior to the implementation of the emergency energy conservation procedure.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 15 - RATE FOR PURCHASE OF ELECTRIC ENERGY FROM CUSTOMER-OWNED RENEWABLE RESOURCES GENERATING FACILITIES

The Company will purchase electric energy from customer-owned generating facilities that: (1) are "qualifying small power production facilities" as defined in Subpart B - Qualifying Cogeneration and Small Power Production Facilities, of Part 292 of Subchapter K of Chapter 1, Title 18, Code of Federal Regulations ("facility"); (2) are located in the Company's service area; (3) use as the energy source renewable resources such as small scale hydro facilities of 30 megawatts or less, biomass, waste, solar or wind; and (4) meet one of the following three criteria:

(a) are subject to a contract dated prior to August 25, 1987, and are supplying electric energy, or have commenced construction of facilities to supply electric energy within sixty (60) day of August 25, 1987.

(b) are supplying electric energy to the Company under the terms of this rider on or before August 25, 1987, but are not subject to an executed contract.

(c) have been negotiating with the Company for a contract and it is determined that the project has been the subject of serious negotiations prior to August 25, 1987.

The electric energy will be purchased, as available, from such facilities at the rate of six (6) cents per kilowatt-hour, or at a rate based on the Company's avoided costs when such costs exceed six (6) cents per kilowatt-hour. For facilities that do not qualify under the provisions of this rider, electric energy will be purchased at a rate based on the Company's avoided costs as calculated in accordance with the applicable PA. P.U.C. regulations. Payment will be made monthly for the electric energy received from the facility in the preceding month.

Each facility will be required to install at its expense, or to have the Company install at the customer's expense, interconnection equipment and facilities including metering, protection and controls. All such interconnection equipment and facilities must be reviewed and approved in writing by the Company prior to installation.

The owner of each facility will be solely responsible for the operation, maintenance and repair of such facility.

The Company shall not be liable for damage to the facility which may result from its interconnection with the Company's facilities.

This rider shall be effective only so long as the cost of such energy purchased by the Company may be recovered by the Company through its Energy Cost Rate or its equivalent in the future.

Purchase of electric energy under this rider shall be subject to all applicable Rules and Regulations of the Company's Electric Service Tariff, such Rules and Regulations to be read and interpreted, generally, with the word "purchase" substituted for the word "supply" or the word "service" where appropriate to reflect the application of the Rules and Regulations to the purchase rather than the sale of electric energy.

The Company reserves the right to require a written contract covering the purchase of electric energy for each facility.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SMALL BUSINESS DEVELOPMENT RIDER

(Applicable to Rate GS/GMD)

PURPOSE

Stimulating development of small industrial facilities in Duquesne's economically distressed service area may produce benefits in terms of job creation, increased regional income, and improved living standards. The purpose of this rider is to encourage load management, increase regional industrial production, and grow employment through an incentive for small industrial customers.

AVAILABILITY

This rider will be available for a period not exceeding five (5) years to qualifying new industrial customers having estimated annual load requirements not exceeding 105 kW. Qualifying terms and conditions are listed below.

ECONOMIC INCENTIVE

A qualifying customer will earn a separately stated credit equal to the Billing Demand and Duquesne supplied energy charge minus the 5Kw multiplied by the discounted Incremental Unit Capacity delivery Charge of Rate GS/GMD. The percentage discount is 50% for the first 36 months, 30% for the next 12 months and 15% for the last 12 months the customer is on this rider. The credit will be applied to the customers fixed CTC.

NOTE

Except for the provisions specifically set forth in this rider, all provisions, prices, and regulations of the standard general service rate under which the customer receives service shall apply.

The preceding credits will be applied before application of Rider No. 10 - State Tax Adjustment. All applicable "Standard Contract Riders" will remain in effect. The Minimum Charge Provision of Rate GS/GMD shall not be reduced by this rider.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SMALL BUSINESS DEVELOPMENT RIDER - (Continued)

(Applicable to Rate GS/GMD)

DEFINITIONS

1. **New Service Location** - A location having one or more delivery points for electric service which will be billed separately by the Company under a single billing address to which the Company has not previously supplied electric delivery service

2. **Existing Service Location** - An existing location of a customer having one or more delivery points for electric service billed separately by the Company under a single billing address.

3. **Employment Reports** - The "Employer's Report for Unemployment Compensation" and "Employer's Quarterly Report of Wages Paid to Each Employee" as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania and the "Employer's Quarterly Employment and Wage Analysis" as filed by the customer with the Office of Employment Security, Department of Labor and Industry, Commonwealth of Pennsylvania for employers who have more than one place of business in the Commonwealth.

TERMS AND CONDITIONS

1. The customer must be a new or an existing customer.

2. The customer must be engaged in manufacturing or processing operations as defined in the Division D. Manufacturing Standard Industrial Classification (SIC) categories as described in the 1987 Edition of Standard Industrial Classification Manual, supplements thereto, or later editions.

3. A Pennsylvania Sales Tax Blanket Exemption Certificate must be filed by the customer with the Company as soon as it is filed with the Commonwealth showing the address of the service location to which the rider is to be applicable and certifying that more than fifty percent (50%) (on an annual basis) of the electricity purchased thereunder is exempt from sales tax because it is used in manufacturing or processing operations. The rider shall not be effective until the Certificate or other suitable evidence acceptable to the Company is filed with the Company assuring that the above usage criteria is being achieved.

4. Current "Employment Reports," as defined, must be filed with the Company no later than thirty days after the end of the reporting quarter as defined at 43 P.S. 753d.

5. In the event a customer's load consistently exceeds 100 kW, the customer will be given the discount applied to a maximum of 100 kW of load.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SMALL BUSINESS DEVELOPMENT RIDER - (Continued)

TERMS AND CONDITIONS - (Continued)

(Applicable to Rate GS/GMD)

6. The customer must sign a five (5) year "Economic Development Rider No. 13 Amendment to Electric Service Contract." Failure to comply with the terms and conditions of the contract may result in the cancellation of this rider.

7. The Company reserves the right to refuse this rider to customers who do not meet the conditions specified above.

8. The application of the rider will be discontinued if bills are not paid when due as specified in Tariff Rule No. 21, before the addition of a Late Payment Charge.

9. The rider will be reserved for a customer who applies to the Company for the rider in writing up to twelve months prior to the time service is required.

10. Discontinuance of or detrimental changes to the rider will not apply to an existing rider participant or a prospective participant as described in Condition (9).

MARKET PRICES IN ECAR AND PJM ($/MWH)

	ECAR [1]	PJM [2]	Price Difference [2]/[1]-1
1997 to date			
On-Peak	21.17	24.56	16%
Off-Peak	14.12	16.55	17%
Hourly Wtd. Average	**$17.47**	**$20.36**	17%
1996			
On-Peak	22.52	25.29	12%
Off-Peak	14.30	15.46	8%
Hourly Wtd. Average	**$18.20**	**$20.13**	11%

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.

Source: The McGraw-Hill Companies' Power Markets Week

MARKET PRICES IN ECAR AND PJM

1997	On-Peak Index Price ($/MWH)			Off-Peak Average Price ($/MWH)		
Week Ending	ECAR [1]	PJM [2]	Price Difference [2]/[1]-1	ECAR [4]	PJM [5]	Price Difference [5]/[4]-1
01/10/97	22.76	26.36	16%	13.50	16.00	19%
01/17/97	34.31	34.30	0%	16.50	18.50	12%
01/24/97	16.67	28.14	69%	14.50	17.00	17%
01/31/97	23.60	29.81	26%	15.50	19.75	27%
02/07/97	16.94	24.30	43%	12.50	17.50	40%
02/14/97	18.25	26.51	45%	14.50	18.50	28%
02/21/97	15.94	23.53	48%	14.00	18.00	29%
02/28/97	17.65	22.37	27%	14.50	16.75	16%
03/07/97	18.86	23.14	23%	14.00	17.25	23%
03/14/97	16.93	22.99	36%	12.75	16.50	29%
03/21/97	18.27	23.64	29%	14.50	17.50	21%
03/28/97	17.09	22.75	33%	13.25	17.00	28%
04/04/97	17.32	20.76	20%	14.00	17.13	22%
04/11/97	20.78	20.16	-3%	14.25	16.45	15%
04/18/97	22.06	22.12	0%	14.00	17.94	28%
04/25/97	19.61	20.93	7%	14.38	16.50	15%
05/02/97	18.15	20.06	11%	13.00	15.00	15%
05/09/97	18.99	22.77	20%	14.50	17.00	17%
05/16/97	17.61	21.31	21%	15.00	15.50	3%
05/23/97	16.57	20.71	25%	14.00	15.00	7%
05/30/97	15.60	17.84	14%	13.50	14.50	7%
06/06/97	16.47	17.39	6%	NA	NA	NA
06/13/97	17.28	22.98	33%	12.50	11.00	-12%
06/20/97	20.02	21.32	6%	14.50	14.25	-2%
06/27/97	52.93	44.97	-15%	14.50	17.63	22%
07/04/97	36.99	34.62	-6%	14.50	16.75	16%
07/11/97	23.84	27.47	15%	14.50	15.50	7%
Average Price	21.17	24.56	16%	14.12	16.55	17%

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.

Source: The McGraw-Hill Companies' Power Markets Week

MARKET PRICES IN ECAR AND PJM

1996	On-Peak Index Price ($/MWH)			Off-Peak Average Price ($/MWH)		
Week Ending	ECAR [1]	PJM [2]	Price Difference [2]/[1]-1	ECAR [4]	PJM [5]	Price Difference [5]/[4]-1
01/12/96	20.30	33.25	64%	13.00	20.50	58%
01/19/96	18.35	31.00	69%	14.00	17.50	25%
01/26/96	22.35	29.50	32%	17.00	17.75	4%
02/02/96	25.40	29.75	17%	16.25	18.00	11%
02/09/96	29.00	37.80	30%	22.75	24.00	5%
02/16/96	20.95	30.00	43%	15.00	20.25	35%
02/23/96	18.90	25.50	35%	14.63	18.75	28%
03/01/96	20.50	24.00	17%	13.50	15.00	11%
03/08/96	24.60	27.50	12%	16.00	17.50	9%
03/15/96	20.00	25.25	26%	14.75	17.50	19%
03/22/96	24.43	25.15	3%	17.00	17.00	0%
03/29/96	22.45	26.25	17%	15.50	18.75	21%
04/05/96	19.75	22.70	15%	14.50	17.25	19%
04/12/96	19.98	21.40	7%	16.50	15.00	-9%
04/19/96	19.20	20.50	7%	14.75	13.45	-9%
04/26/96	18.90	19.70	4%	13.50	12.50	-7%
05/03/96	18.90	19.25	2%	13.75	13.00	-5%
05/10/96	19.25	19.10	-1%	12.50	12.00	-4%
05/17/96	20.00	19.59	-2%	14.50	12.00	-17%
05/24/96	29.52	28.85	-2%	16.00	17.00	6%
05/31/96	19.69	19.50	-1%	13.50	12.25	-9%
06/07/96	18.50	20.45	11%	12.50	12.00	-4%
06/14/96	20.73	27.40	32%	13.50	14.50	7%
06/21/96	32.53	28.38	-13%	15.50	14.50	-6%
06/28/96	36.49	29.44	-19%	15.00	14.50	-3%
07/05/96	29.67	25.42	-14%	13.50	13.50	0%
07/12/96	22.78	25.38	11%	13.50	15.50	15%
07/19/96	38.09	34.80	-9%	14.50	16.25	12%
07/26/96	24.44	25.83	6%	13.00	15.00	15%
08/02/96	17.35	24.98	44%	11.75	14.00	19%
08/09/96	39.10	34.34	-12%	16.00	16.00	0%
08/16/96	18.30	21.87	20%	13.00	13.00	0%
08/23/96	30.13	29.57	-2%	13.50	15.00	11%
08/30/96	19.65	22.00	12%	12.50	15.00	20%
09/06/96	20.30	23.88	18%	13.50	14.38	6%
09/13/96	20.70	27.75	34%	12.00	16.00	33%
09/20/96	17.27	20.91	21%	11.75	13.00	11%
09/27/96	17.31	20.84	20%	11.75	14.25	21%
10/04/96	17.20	20.61	20%	11.75	14.75	26%
10/11/96	17.64	21.72	23%	13.00	14.65	13%
10/18/96	17.54	23.24	32%	13.00	14.90	15%
10/25/96	18.45	21.77	18%	13.50	13.50	0%
11/01/96	21.50	24.15	12%	14.00	14.25	2%
11/08/96	20.57	25.31	23%	14.50	15.25	5%
11/15/96	29.95	29.41	-2%	17.13	16.25	-5%
11/22/96	22.72	23.82	5%	15.70	16.38	4%
11/29/96	25.69	25.04	-3%	15.00	15.75	5%
12/06/96	23.91	24.99	5%	14.88	15.50	4%
12/13/96	20.25	25.97	28%	14.88	15.50	4%
12/20/96	30.98	29.28	-5%	17.13	16.00	-7%
12/27/96	14.71	22.34	52%	12.25	13.00	6%
01/03/97	13.98	18.69	34%	11.50	15.13	32%
Average Price	22.52	25.29	12%	14.30	15.46	8%

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.

Source: The McGraw-Hill Companies' Power Markets Week

Duquesne Statement No. 5-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Rebuttal Testimony
of
James A. Lahtinen

Contents:

Response to Intervenor Testimony on Duquesne's Market-based RFP and CGC Determination, the Unbundled Allocated Cost of Service, and Duquesne's Proposal to Redesign its Tariffs to Mitigate Stranded Costs

REBUTTAL TESTIMONY OF JAMES A. LAHTINEN

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. Are you the same Mr. Lahtinen that filed direct testimony earlier in this proceeding?

A. Yes. I submitted direct testimony, Duquesne Statement No. 5, in the Duquesne Restructuring Plan filing on issues pertaining to the allocated cost of service, market prices, and unbundled rate design.

Q. What is the purpose of your rebuttal testimony?

A. My primary purpose is to respond to intervenor testimony regarding the following major topics:

- Duquesne's proposal to use the results from an annual RFP process to establish market power prices and customer generation credits (CGCs),
- Duquesne's unbundled allocated cost of service study (In this section I will also comment on ENRON witness Reising's proposed cost unbundling proposal.)

- Duquesne's proposal to unbundle and redesign its tariffs towards more *efficient* levels in order to mitigate stranded costs.

Q. I take it that your responding testimony is organized along these lines.

A. That is correct.

Q. Could you please summarize your major conclusions?

A. Yes, I have three of them, one for each major topic above.

Q. Please summarize your first conclusion regarding the RFP and necessary adjustments to establish a customer generation credit.

A. The intervenors launch attacks on two fronts in an attempt to criticize Duquesne's proposal to rely upon market evidence in setting customer generation credits (CGCs). The first front attacks the RFP process head on, while the second front comes equipped with a barrage of "adder" adjustments. I find the criticisms against Duquesne's annual RFP process and the results from its 1997 solicitation to be nothing more than a collective wish to ignore reality. And that reality is the existence of available coal-fired capacity in ECAR that tends to "depress" the current market value of power in the region.

I am equally unimpressed with the rationale offered to support the legitimacy of upward adjustments to the RFP market price to either include costs the RFP process "misses" or to recognize the "spread" between retail and wholesale prices. In large part these adjustments are offered to account for what the intervenor witnesses describe as the high transaction costs involved with selling at retail,

leaving one to wonder why we are moving to competition in the first place. If adopted by the Commission, these "markups" and "incentives" will create new stranded costs during the transition period as readily acknowledged by several witnesses for the intervenors. Finally, Duquesne is proposing to modify its market-based proposal to include avoidable distribution line losses in the CGC based on intervenor comments. Duquesne will continue to adjust for customer class time-of-use consumption patterns, transmission losses and gross receipts tax in establishing market-based CGC's. In addition, Duquesne will apply a market-based credit for ancillary services that can be competitively procured.

Q. What is your second major conclusion regarding the unbundled allocated cost of service?

A. Many of the objections to Duquesne's allocated cost of service appear to be veiled attempts to shift costs from distribution to the production function with the effect of denying the Company the opportunity to recover its stranded costs through a CTC. (It should be pointed out that OSBA witness Kalcic's proposal is different from that recommended by ENRON witness Reising in that he appears to allow Duquesne the opportunity to recover these costs through the CTC.) Duquesne has unbundled its costs using methodologies consistent with those used in the Company's most recent base rate proceeding, and the guidance provided in FERC Order 888. However, consistent with our proposed modification to the CGC's described above, Duquesne will remove the cost of supplying distribution losses from the distribution charges and put them back into generation. The CGC will

be adjusted to reflect avoidable distribution losses thereby allowing customers the choice of having their suppliers provide these losses. As a result, Duquesne will either directly charge suppliers for distribution losses or allow them to supply them on their own account.

Q. Please summarize your third major conclusion regarding Duquesne's proposal to unbundle rates and redesign its tariffs.

A. Finally, all but a few of the intervenor witnesses fail to properly comprehend the benefits they propose to deny consumers by rejecting Duquesne's rate design proposal. Their arguments mostly invoke concerns over cost-shifting. Either the intervenor witnesses have absolutely **no** understanding of the difference between cost shifting (which the Act prohibits) and revenue shifting (which happens whenever customers change consumption between rate years under any rate design) or their objections have absolutely nothing to do with efficiency, adequacy, or fairness. Duquesne's rate design utilizes customer-specific CTC's in order to prevent cost shifting within and among customer classes. For those customers who continue to purchase electricity from Duquesne, the unbundled rates will result in the same bill the customer would otherwise pay under current bundled rates (adjusted for the ECR roll-in) assuming 1996 test year sales levels.

The intervenor witnesses also fail to recognize the stranded cost mitigation potential of Duquesne's proposed rate re-design ($15 million per year). The restructuring legislation contemplates that utilities will undertake efforts to fully

mitigate stranded costs and rate re-design affords Duquesne one of the best opportunities to do so.

Nonetheless, some have argued that the new rate design is confusing and could raise equity concerns for customers that reduce consumption. In response, Duquesne will accept OSBA witness Kalcic's recommendation that customers be given a choice between a simple unbundled rate structure or Duquesne's more efficient rate proposal. Offering an option should put to rest any intervenor concerns over the fairness of Duquesne's rate re-design proposal.

The remainder of my rebuttal testimony supports these conclusions in greater detail.

II. THE MARKET PRICE OF POWER AND ESTABLISHING THE CGC

Q. Mr. Lahtinen, several witnesses have taken exception with your use of the RFP price for purposes of setting the CGC. Could you first categorize the arguments raised by the intervenors and then respond?

A. I will try. Several witnesses raised concerns over setting the CGC's on the basis of prices obtained from Duquesne's proposed RFP process. I will not deal here with each witness individually since many of them raise the same arguments. (However, I am attaching Exhibit JAL-14 that responds to the plethora of specific attacks on Duquesne's proposal.) I believe it is possible to summarize the opinion

of the opposing parties along the following lines:

- The RFP price is a downward biased estimate of the wholesale commodity price.
- Even if the RFP price was a reasonable measure of the wholesale commodity price, it still would be too low since it does not include the value of capacity, installed reserve requirements, and the costs of ancillary services.
- Even if the RFP was "properly" adjusted to reflect wholesale prices, it is not an accurate measure of the retail market price because it fails to adjust for distribution line losses, overheads, and marketing costs that competitors will bear.

A. The RFP Approach Provides An Accurate, Known and Measurable Market Price At Which Duquesne Can Sell Power When Retail Load Chooses Alternative Suppliers

Q. How do you respond to the first point raised by the intervenor witnesses that the RFP is downward biased?

A. First, I would like to address the issues Mr. Russell raises on behalf of MAPSA regarding the design of the RFP at pages 25-27 of his testimony. There he asserts that the design of Duquesne's RFP encouraged low bids because the take provisions of the power sale are inflexible reducing its market value as a product for sale at the retail level. He also suggests that recent postings by Duquesne of no firm ATC indicate that purchasers under the RFP will be left with non-firm

transmission service further reducing the appeal of the power product. Finally, he asserts that the relatively short response time between issuance of the bid and the date on which bids were due resulted in discounted bid prices to hedge against the uncertainty created by the "time constraints".

Q. How do you respond?

A. First, the product Duquesne offered for sale under its RFP was designed to enhance value and is appropriate to calculate stranded costs for Duquesne customers. Duquesne's generation portfolio is comprised primarily of baseload units. The minimum 50% capacity factor appropriately recognized that these units cannot be "cycled" below certain minimum levels. In addition, a 75% capacity factor is an appropriate product because it essentially combines a baseload product with a sale of on-peak power. Finally, as discussed in my direct testimony, Duquesne has proposed to adjust the winning prices from the RFP to account for the hourly differences in usage among Duquesne's rate classes, thus transforming the RFP price to a class-specific retail price.

Q. Could Duquesne have used a different capacity factor in the RFP for purposes of establishing the CGC?

A. Yes, but it is unlikely to have a significant effect on the market price.

Q. Would using a 100% capacity factor (i.e., all hours) sale provide a better estimate of the market price?

A. No. An all hours sale would undoubtedly lead to a lower average price from the RFP process, because the price would reflect an equal weighting of on-peak and

off-peak hours. However, this price would need to be adjusted upward to recognize customer class usage patterns.

Q. Would using an on-peak only (i.e., "5 by 16") sale provide a better estimate of the market price?

A. No. An on-peak "5 by 16" sale refers to selling power in the sixteen on-peak hours during Monday through Friday. A "5 by 16" sale would undoubtedly lead to a higher average price from the RFP process because the price would reflect only the on-peak hours. As a result, this higher price would then need to be adjusted downward to reflect the customer class load pattern.

Q. Why do you claim that the RFP was designed to enhance value?

A. While Duquesne could require purchasers to take an all hours or a "5 by 16" contract, it would afford a potential purchaser no flexibility to vary schedules. The product Duquesne has proposed to sell under the RFP (indeed, sold in its 1997 solicitation) is intended to provide purchasers with scheduling flexibility between 50% - 100% in any hour.

Q. Why did Duquesne's 1997 RFP impose a 50% minimum take in any hour and specify an annual capacity factor of 75%?

A. Duquesne witness Mr. Irvin informs me that the 50% minimum hourly take is necessary for operational reasons. This allows Duquesne's generating units to be backed down, but does not require them to be taken off-line during minimum daily load periods when Duquesne's system load is at its lightest (roughly 50 percent of on-peak demands). The annual capacity factor requirement is

necessary in order to establish a known and measurable contract quantity and market price.

Q. Did Duquesne consider other factors in developing the RFP?

A. Yes, the Company spoke with several traders who are actively engaged in buying and selling wholesale power through competitive solicitations prior to designing the RFP. These discussions revealed that potential purchasers were most concerned with two things: a) the sincerity of the offer and b) the ability to take power during the peak period. Traders who we spoke to indicated that bidders were primarily concerned that the offer was credible. As Mr. Irvin states in his direct testimony, this is why Duquesne made a commitment to sell power to the highest bidder(s) because in his experience "it is not uncommon for a utility to conduct an RFP without following through by awarding capacity and energy to the winning bidders". (See Irvin direct at page 7.) In fact, Mr. Irvin informs me that neither of these issues ever came up during his discussions with any of the parties who contacted him about Duquesne's RFP.

Q. How do you respond to Mr. Russell's second assertion that the bid prices were depressed because of the possibility that firm transmission would be unavailable?

A. First, the argument is disingenuous because, under the power sales agreement, the purchaser does not bear the risk of transmission constraints on the Duquesne system. Duquesne specifically modified Section 6 of the PSA, at the behest of interested bidders, to provide that, if there were transmission constraints on the Duquesne system, Duquesne would be required to deliver the power at other

delivery points. Consequently, the claims of Mr. Russell and Mr. Weisenmiller that the power was "non firm" because of the lack of "firm transmission" are meritless. Second, it is astonishing that Mr. Russell would suggest that Duquesne should have included firm transmission in the RFP, thereby "bundling" transmission rights with the firm power offering. At every occasion in other portions of Mr. Russell's testimony, he criticizes Duquesne for bundling any services together. Third, given that these witnesses criticize the RFP for having "inflexible" terms, one would think that the most flexible power product would be one in which the purchaser, rather than Duquesne, chooses the necessary transmission service. In this way, it can purchase the service most appropriate and economic to its needs, as Order No. 888 permits. Finally, there is no evidence that a purchaser will be unable to buy firm transmission on Duquesne's system. Obviously, a purchaser of power in the RFP who chose to sell at retail in Duquesne's service territory would place no additional load on our system. If the transmission system provides adequate capability in a world before retail choice, it follows that the Company will have sufficient firm transmission capability after retail choice begins since the same amount of load will be served using the same transmission network. And more to the point, the power supplied under the RFP will be coming from the same generation sources Duquesne currently uses to serve its retail and full requirement customer. There is absolutely no reason a knowledgeable purchaser under the RFP would be concerned that the transmission service offered by Duquesne under its FERC tariff would be any less firm than the

transmission service Duquesne provides its full requirement customers today.

Q. How do you respond to Mr. Russell's last point concerning time constraints?

A. Mr. Irvin informs me that no bidder (potential or actual) expressed any concern over the fact that bids were due within 3 weeks from the issuance of the RFP. Moreover, the traders who we spoke to indicated that a lead-time as short as 1 week would not be viewed by market participants as an unreasonable time constraint. (It should be pointed out that in subsequent RFP's, the Company could easily extend the response time if this becomes an issue with bidders in the future.)

Q. Mr. David Boonin on behalf of New Energy Ventures, a potential retail supplier, proposes that the unbundled price for generation be determined by the wholesale market. Do you agree with his position?

A. Yes. Duquesne agrees "that this is necessary in order to make choice a reality for retail customers while treating all affected parties equitably."(See direct of Mr. Boonin at page 3.)

Q. Would you accept his argument that the price for generation should be determined by the market-clearing price of the power exchange?

A. Yes, I agree that a power exchange would be a good source for gathering market clearing price data. There is only one problem: a power exchange doesn't exist for Duquesne. This is why Duquesne has proposed to rely upon a competitive RFP process to determine market prices. However, as Mr. Marshall explains, if a power exchange emerges, Duquesne could be willing to terminate use of the RFP

and substitute the PX price.

Q. Since many intervenors have criticized the RFP product and process, would Duquesne consider changing future RFP's that are used to set the CGC and CTC?

A. Yes. The Company would be willing to adopt constructive changes in either contract terms or bidding procedures for future solicitations. Our primary objective is to establish a known and measurable market price for Duquesne's generation. To demonstrate our flexibility, Duquesne will commit to file the RFP with the Commission for prior approval. In this manner, all interested parties may provide suggestions to improve it.

Q. Have any of the intervenors proposed alternative contract terms or procedures for the RFP?

A. No, unfortunately they have not.

Q. Why is this?

A. I am not sure. However, I can only guess that their objective is to shoot down the RFP without providing the Commission any market-based alternative, thereby leaving the Commission no choice but to set CGCs using an administrative "forecast" method. I must conclude this because of the inordinate effort they expend on criticizing every facet of the RFP. I consider most of these objections to be so unfounded, and contrary to accepted economic principles, as to merit no response. However, I am concerned that the Commission may be mislead by these statements and that, if unrebutted, the intervenors will claim that they have identified "unrebutted" flaws in the RFP. For this reason, I have taken the time to

itemize each criticism (including those related to other aspects of CGC calculation and unbundling) and provide a specific response in Exhibit JAL-14 attached hereto.

Q. Do you agree with Mr. Boonin's recommendation that the unbundled CGC and CTC always be kept in balance so that the total of the two never varies and never exceeds the rate cap?

A. Yes, this is a pillar of Duquesne's unbundling proposal. If market prices increase over time (as revealed in the competitive RFP), the CGC would increase and the CTC would fall accordingly, and vice versa. As Mr. Boonin correctly points out on page 5 of his testimony, the electricity price will vary depending on market conditions and "the appropriate unbundled price of generation should also vary with the market and not be fixed." This "frees the Commission from the impossible task of accurately predicting the prevailing market price of generation." Mr. Boonin correctly observes that this "approach is also consistent with the intent of the legislation which is to deregulate the price of generation, not to reestablish a regulated price of generation on a different concept than historical rate base regulation." I agree that this approach is "far more accurate than one based upon a one time estimate of market prices." (See Boonin direct at page 17.)

B. The RFP Approach Appropriately Accounts for Capacity, Installed Reserves and Ancillary Services

Q. Please respond to the second set of arguments that the RFP price is too low

because Duquesne failed to make adjustments necessary to fully measure the market value of wholesale power.

A. Based on my reading of the intervenors' testimony, the criticisms can be grouped along the following lines:

- The RFP price is an energy only value,
- A value for capacity plus an adjustment for installed reserves is necessary, and
- The market price must also be adjusted for the cost of ancillary services.

First, it is clear that many of the intervenors either did not read or did not understand our proposal to use the RFP price as the basis for setting the CGC, nor our treatment of ancillary services. Second, it is quite clear that many of the intervenors would prefer that Duquesne be required to set a high CGC as opposed to a market-based one, since customers would have a greater incentive to switch to an alternate supplier and/or suppliers would have a greater opportunity to make a profit. Most importantly, the rationale supporting the intervenors' arguments for adjusting the RFP price are conceptually flawed and should be rejected by the Commission.

Q. Please begin by summarizing the opponents' assertions that the RFP price is an energy-only price.

A. Certainly. Again Mr. Russell states the case most clearly for the intervenors. He argues that the prices set in the RFP "are more akin to bulk power rates into a power exchange than the rates to individual customers within a market region". He therefore concludes that "they reflect only a part of the value of the power

supplied". (See Russell direct at page 21.) Presumably, this means that the RFP price reflects only the energy value for wholesale exchanges in the ECAR region. This is clearly not the case. The power that is provided under the RFP is a firm obligation to sell electricity, as well as a financial obligation to pay replacement costs if Duquesne fails to perform. The bottom line is that Duquesne will provide the power or pay the supplier replacement costs holding the purchaser harmless. That is precisely the definition of firm power in today's market, as explained by Mr. Irvin.

This sale is not akin to a spot or non-firm sale of power into a power exchange as Mr. Russell asserts. I suspect that the real objection Mr. Russell and others have with the RFP price is that the "market" doesn't place as much value on firm power as these "experts" would like. The fact that capacity has little or no value in the ECAR region is a reality that everyone, most of all Mr. Russell, wants to ignore in this proceeding.

Q. Has Duquesne provided additional evidence in this case on the capacity value of generation within the ECAR region that supports the results from the RFP?

A. Yes. And it is interesting, although not surprising that no intervenor mentions it. I find it interesting because this data was provided in Mr. Irvin's direct testimony and again by me in response to discovery request DII-2-04. That data indicated a peak capacity value ranging between $0.43/kW/year to $1.06/kW/year during 1996 and 1997. I am not surprised no one mentions this because it does not support claims by Duquesne's opponents that capacity has substantial value in the

ECAR region.

Q. What is the source of this data?

A. This data comes from actual prices Duquesne paid for the rights to call upon a specified amount of generating capacity. As Mr. Irvin describes in his direct testimony, Duquesne made two capacity purchases over the past two years. In 1996, Duquesne purchased the call rights on 75 MW's of capacity for 6 weeks at a price of $32,000 or $0.9 per MWH after factoring in the number of on-peak MWH. A similar arrangement was made during the summer of 1997 but only for 50 MW's over a nine-week period. The reservation price in this case was $52,800 or $1.5 per MWH after adjustment for the number of on-peak MWH. It should also be pointed out that these prices represent capacity value during Duquesne's summer peak period, indicating that similar purchases of reserved capacity during times of lighter demand could be obtained at lower prices. As a result, the effective annual price for peaking capacity is likely to be even lower than indicated by the above figures.

Q. Is there anything else notable about these capacity purchases?

A. Yes. They were unencumbered by any of the "flaws" that the intervenors attach to the RFP. They were negotiated at arms-length between two parties. No pre-specified terms were set. There was no auction. There was no "short" response time. Yet, the capacity prices produced in these negotiations are entirely consistent with the RFP prices.

Q. Is there any other evidence of which you are aware that corroborates the RFP

prices?

A. Yes. The OCA's market price witness, Mr. Smith, has predicted a price stream during the transition period that mirrors the prices produced by Duquesne's 8-year RFP, with only exception being a forecast by Mr. Smith that prices will "bump up" in 2003 to reflect new capacity additions. Whether or not this occurs is, of course, anyone's guess, but I find it interesting that Mr. Smith's projection otherwise is entirely consistent with the results of Duquesne's supposedly "flawed" RFP.

Q. What is your response to those who argue that Duquesne's estimate of market value fails to make a necessary adjustment for installed reserves?

A. It is correct that Duquesne does not adjust the RFP price for installed reserve margins. This is because the RFP price fully reflects this value. As explained by Duquesne witness Mr. Karl, Duquesne has traditionally maintained installed reserves to serve retail load. Now that we have sold firm power in the RFP, Duquesne will continue to maintain installed reserves to support that firm sale. In effect, there is little difference between selling retail and wholesale from the standpoint of the generator. This is consistent with the "firmness" issue described above. Winning RFP suppliers need not worry about acquiring additional installed reserves since the RFP provides the purchaser with the reliability needed to serve retail load.

Q. Will retail suppliers be required to carry installed reserves in order to sell at retail in Duquesne's service territory?

A. As Mr. Karl explains, Duquesne and other ECAR companies do not have installed reserve requirements like the PJM companies. As a result, neither the RFP price nor its capacity component equivalent requires any adjustment for a requirement that does not exist. As explained by Mr. Karl, Duquesne plans to maintain installed reserves of 12% for its full requirements customers consistent with the Company's continued obligation to serve during the transition period. However, Duquesne will not impose an installed reserve requirement obligation on competing suppliers. The Company agrees with Enron witness Coles that the level of installed reserves should be set by market participants, not by regulatory fiat.

Q. So are you saying that the RFP price you propose as the basis for setting the CGC's fully reflects the market value of both energy and capacity, including installed capacity reserves?

A. Yes. Furthermore, I am saying that any adjustment for reserve margin requirements would overstate the market value of power in the ECAR region and would be inconsistent with current requirements.

Q. Several witnesses suggest that the CGC should be adjusted by adding thereto Duquesne's proposed ancillary service rates. How do you respond?

A. That proposal mixes apples and oranges. The purpose of the CGC is to provide a credit for the market value of generation services that can be competitively procured. It is not a measure of regulated "cost" of service.

Q. Then how would Duquesne ensure that it does not collect ancillary service costs twice -- once from customers and once from suppliers?

A. Ancillary services will be charged (or credited) with regard to whether the particular service can be competitively procured (i.e., is akin to the market for deregulated generation sales) or cannot be competitively procured (i.e., is akin to a "wires" service, such as transmission or distribution). If it is the former, and can be competitively procured (today, only supplemental reserves falls in this category), Duquesne will treat it just like competitively procurable power: a market-based credit will be computed and added to the CGC, which in turn reduces the CTC by the market value of the generation-based ancillary service. (For example, as to supplemental reserves, a market based credit would be added to the CGC that reflects the pure cost of generating capacity (currently approximately 1.5 mills/kWh).) If it is the latter, and the service cannot be competitively procured, Duquesne will treat it just like other wires services: the customer will continue to pay a cost-based, FERC-approved rate and suppliers will not be obligated to supply it.

Q. Some suppliers contend that Duquesne is thwarting the development of a competitive market by not making all these ancillary services competitively procurable. How do you respond?

A. Their complaints are with ECAR, not with Duquesne. Duquesne does not set the rules; it follows them. As indicated in Mr. Irvin's direct testimony, Duquesne will abide by Order No. 888, which requires transmission providers to permit their customers to self-provide ancillary services to the extent it is technically feasible under applicable regional reliability council standards.

Q. MAPSA witness Mr. Russell and OCA witness Ms. Smith assert that ancillary service costs are primarily generation-related and should be included in generation. How do you respond?

A. Ancillary services that can be competitively procured, such as supplemental reserves, will be included in generation. As noted above, a market-based credit will be computed and added to the CGC. The remaining embedded costs will be reflected in the CTC. Those ancillary services that cannot be competitively procured will be included in transmission rates.

C. Other Adjustments For Customer Time-of –Use Consumption, T&D Losses and GRT Are Necessary

Q. Please summarize the arguments put forth by the opposing parties that since retail market prices will be higher than the wholesale power prices, your CGCs are too low and should be adjusted upwards by the Commission?

A. The intervenor witnesses present four main arguments:

- Duquesne's take provisions in the RFP do not reflect actual retail customer consumption patterns
- Duquesne's CGCs must include distribution line losses to reflect the market value of power at the retail level,
- Duquesne's market price estimate needs to be adjusted for A&G expense adders,
- Duquesne's market price estimate needs to be adjusted for retail marketing

costs.

Q. What about the first issue?

A. Several intervenors criticize the take provisions of the RFP and express concern that these do not reflect customer consumption patterns. Ms. Smith states that it is not clear how the Company adjusted the wholesale market price to reflect average system load shape. (Direct testimony of Ms. Smith, p. 10) These criticisms are unfounded. I provided a detailed description of the methodology I used to convert the RFP price into a customer class load-weighted CGC. (See Lahtinen direct testimony pp. 54-61.) I even prepared a simplified example to illustrate the approach.

Q. Please address the issue regarding distribution line losses.

A. ENRON witness Reising, OCA witness Lee Smith, and DIIC witness Baron all argue that Duquesne has improperly included the cost of distribution line losses in its distribution tariff and therefore understated the CGCs. Mr. Reising is the most vociferous opponent of our proposal.

Q. How do you respond to this complaint?

A. Duquesne's original proposal would have provided the distribution losses for all load served within our territory, eliminating the option of competitive procurement. This is the same logic Duquesne applied in its treatment of reactive power, frequency control, and operating spinning reserves. It is important to point out that our proposal would not have resulted in customers paying twice for distribution losses since Duquesne would have provided this service for all

customers within our territory regardless of their power provider. However, Duquesne has no objection to removing the cost of losses from its distribution tariff and making them available at market-based prices or allowing suppliers to competitively procure their own distribution losses. (It is interesting to note that not one of the intervenor witnesses referenced Duquesne's offer to make this change - DLC response to Environmentalist 3-157.) However, it should be pointed out that the vast majority of these costs are associated with the capacity cost of distribution line losses which reflects Duquesne's embedded cost of generation. As such, Duquesne will now include these costs as part of the generation cost component for cost of service purposes. These non-avoidable costs will be recovered in the CTC. In addition, Duquesne will reflect the market value of distribution line losses in its CGCs, as requested. Exhibit JAL-15 shows the class-specific CGCs reflecting transmission and distribution losses as well as the gross receipts tax adjustment.

Q. Do you agree with those witnesses who say that the CGCs need to be adjusted to reflect an A&G adder?

A. Absolutely not. The rationale for this adjustment is confused and confusing. It points out a fundamental misunderstanding of the relationship between market prices and how overhead costs will be recovered in a competitive market. The argument in favor of an adjustment for overheads is made most clearly by OCA witness Lee Smith. At page 10 of her direct testimony she says that "an appropriate amount of administrative and general expenses should be in an

avoidable generation rate component which should be added to the wholesale price to determine the appropriate avoidable generation credit for retail customers". The effect of her proposal is to add almost $4 per MWH to an administrative estimate of market prices. Presumably, Ms. Smith would apply the same adder to Duquesne's market-based RFP price assuming the PaPUC adopted it.

Q. What is your reaction to Lee Smith's testimony?

A. Surprise. I am surprised because another OCA witness named Smith (Doug) quite correctly observes that in a competitive market, a generator will receive a market clearing price "equal to or greater than its own bid price, resulting in a "contribution" of net revenue to offset the generator's fixed costs of owning and operating its generating source(s)". (See Doug Smith Direct at page 11.) There is absolutely no reason to expect that market clearing prices in a competitive market will reflect the marginal cost of power plus an A&G "adder", whether the sale is at the wholesale or retail level. Individual competitors are price takers, not price setters, in a workably competitive market. Competitive suppliers will compete to supply the demand for the commodity electricity up to the point where the marginal cost of the least efficient (i.e., highest supplier) producer is equal to the marginal value consumers place on the use of electricity for heating, lighting, or operating machines. Since the market clearing price is set by the least efficient supplier providing power in the marketplace, all other power suppliers selling into the market at the same time, will receive revenues that cover their out-of-pocket

costs plus some contribution to overheads and profit ("fixed cost contribution"). Of course, it is also true that more efficient suppliers will enjoy higher levels of "fixed cost" contribution, than less efficient suppliers But this is exactly how competition is supposed to work The adjustment for A&G expenses proposed by OCA witness Lee Smith and some of the other intervenor witnesses should be rejected by the Commission. Indeed, OCA witness Doug Smith makes a compelling case why such an adjustment to market power prices is unnecessary and unwarranted. One of the major goals of this proceeding is to move away from cost-based pricing for generation and toward market-based pricing.

Q. What is the implication of setting the CGC's above market levels?

A. Inefficiency as Mr. Schnitzer explains in his rebuttal testimony and the creation of a new class of stranded costs. Duquesne believes that the purpose of the transition period is to mitigate stranded costs, not create new ones to be dealt with at a later time. Mr. Russell's position on behalf of MAPSA is the exact opposite. He proposes to set the CGC on the high side and "keep track of the extent to which the utility's amortization of stranded costs is penalized or hurt." He goes on to recommend that the Commission allow utilities to recover these additional stranded costs and suggests a possible extension of the transition period. (Russell deposition, pp. 11-13)

Q. Please summarize the testimony of those intervenor witnesses who assert that the wholesale market price estimate needs to be adjusted for retail marketing costs in order to set appropriate class-specific competitive generation credits.

A. Some of the witnesses (e.g., Mr. Russell at page 33) suggest that the Commission place "the utilities' costs of marketing and back-office overhead at risk" by adjusting the CGCs upwards. ENRON witness Mr. Reising on the other hand, argues that sales expense should be removed from Duquesne's distribution tariff and placed entirely in the production-related function for cost of service purposes. He also recommends that the Commission deny Duquesne the opportunity to recover these costs through the CTC because failing to do so will give Duquesne's and its affiliate an unfair competitive advantage. (I will have much more to say about the Reising testimony in a separate section of my rebuttal testimony.) Both recommendations are designed to accomplish the same thing: to deny the Company an opportunity to recover its stranded costs. This is so because both proposals would reduce revenues by an amount equal to the full amount of retail sales expense, ignoring any distinction between avoidable and non-avoidable expenses.

Q. Please explain the Russell proposal.

A. Mr. Russell's proposal would increase the CGCs for retail marketing expenses presumably using Duquesne's test year sales expenses. This approach will simply provide suppliers a higher price umbrella and increase Duquesne's stranded costs.

Q. Has Ms. Smith identified marketing expenses that Duquesne, as a distribution company, can avoid?

A. No. The sales expenses booked by Duquesne in 1996 do not represent the costs Duquesne is likely to avoid if it sells fewer kWh during the transition period This

is because the sales expense category represents costs that have nothing to do with marketing activities at the retail level and includes many costs that are unavoidable overheads. (Mr. Hoffmann explains this in greater detail in his rebuttal testimony.) I simply would point out that the upper limit of avoidable marketing costs provided by Mr. Hoffmann is relatively small, $6.7 million, as one would expect since Duquesne was a monopoly provider of retail service during 1996. In addition, if some portion of these costs are avoidable, Duquesne's restructuring plan called for these savings to be used as mitigation of stranded generation and other asset costs during the transition period.

III. COST OF SERVICE ISSUES

Q. Please describe what areas you will cover in this section of your testimony.

A. I will respond to intervenor criticisms regarding the allocated cost of service study I filed on behalf of Duquesne. These criticisms focused on two main areas: Duquesne's functionalization of costs among production, transmission, and distribution and my use of a required rate of return rather than an overall "realized" rate of return for establishing cost based rates for distribution and transmission service.

Q. Who are the witnesses raising these issues?

A. Mr. Reising testifying on behalf of ENRON sets forth the most detailed rebuttal to the Company's approach to allocating its cost of service He is joined by OSBA witness Kalcic, in attacking my use of the required rate of return instead of an

overall realized rate of return for establishing unbundled costs and ultimately rates for transmission and distribution service. Mr. Reising also proposes that the Company design rates based on the customer's voltage service level rather than historical identification by traditional "class" of service. (See Reising direct pages 25-28.)

A. Duquesne's Functional Cost of Service Study Properly Assigns Costs

Q. Please respond to Mr. Reising's assertion that Duquesne improperly assigned sales expenses, customer information and assistance expense, and a portion of un-collectible accounts expense to distribution.

A. Mr. Reising's proposal to re-assign customer information and assistance expense from distribution to production is poorly conceived and improper.

Q. Can you summarize why you assert that Mr. Reising's position is poorly conceived and improper?

A. Yes, but first I will explain his proposal. Mr. Reising claims that FERC account 908 - customer assistance expense and account 909 - informational and instructional advertising expenses include many expense elements that should be assigned to Duquesne's production, not its distribution function. (See Reising Direct at pages 8-9.) He asserts that each account includes many elements associated with efficient use of electric equipment. Therefore, his recommendation is to remove all of these expenses from distribution and assign them to production because none of these expenses is related to "rendering energy

delivery or revenue cycle services". He does however concede that a portion of the expenses associated with electric line safety (which are included in accounts 908 and 909) might be properly allocated to the distribution function.

Q. How do you respond?

A. Even if Mr. Reising is correct that these costs should not be entirely assigned to distribution, it stretches credulity to conclude that all of these costs should be assigned to the production function. Even in an unbundled world as a regulated monopoly, electric distribution companies (EDC) will continue to have an interest to build and operate their delivery system efficiently This will include incurring expenditures that promote efficient use of the delivery system where it is cost effective to do so. It makes no sense for the Commission to adopt a proposal that would deny an EDC from recovering the costs associated with worthwhile expenditures promoting the efficient use of electricity. Mr. Reising's proposal would leave the EDC no choice but to reject low cost efficiency-related activities in favor of more investments in poles and wires This proposal would result in customers paying delivery service rates that are higher than necessary and should therefore be rejected by the Commission.

Q. Is Mr. Reising correct that the Company included uncollectible accounts expense entirely in the distribution function?

A. Yes, Mr. Reising correctly notes that Duquesne assigned all of its uncollectible accounts expense to the distribution function. I will explain why Mr. Reising's proposal is inherently unfair to Duquesne given its obligation as supplier of last

resort under the Competition Act.

Q. Explain.

A. Mr. Reising argues that the $11 million of uncollectible accounts expense Duquesne includes as a distribution-related cost of service component should be "allocated between production, transmission, and distribution". (See Reising direct pages 10 -11). The recommendation is based on his assertion that an allocated share of these costs is necessary "to create a fair and competitive market." I understand Mr. Reising's position as follows: in a competitive market, all generation suppliers will incur the cost of uncollectibles and therefore, Duquesne's proposal would result in competitive suppliers being unfairly disadvantaged because their customers would pay for uncollectible expenses twice - once through Duquesne's distribution rate and once through their power charge from the supplier. His analysis is flawed because he ignores the fact that under the Competition Act, Duquesne continues to be the supplier of last resort during the transition period while competing suppliers can choose who they serve. This means that ENRON and other suppliers are likely to serve those customers with a much lower risk of payment default, leaving them to be served by Duquesne. This will result in Duquesne continuing to bear most if not all of the uncollectible expenses it incurred during 1996. Moreover, competing suppliers can protect themselves against customer default by requiring customer deposits and including more flexible cancellation provisions than Duquesne can under its obligations under the Public Service Law (and as amended by the Act) throughout

the transition period. These facts suggest that suppliers are unlikely to face an unfair disadvantage in competing against Duquesne for retail customers In fact, the situation may be just the opposite The Commission should reject Mr. Reising's proposal to assign a proportionate share of uncollectible expenses to the production cost function.

Q. Would you care to discuss the allocated cost of service Mr. Reising presents as an alternative to the one you submitted on behalf of the Company?

A. Yes I have two comments about Mr. Reising's study: first I will discuss some of the errors I found in reviewing his results and then I want to illustrate why his proposal to allocate costs (and to then ultimately re-design service classes on the basis of voltage service levels) is fraught with cost-shifting problems and therefore inconsistent with the Competition Act.

Q. What did you find in reviewing the results of Mr. Reising's allocated cost of service study?

A. I reviewed the spreadsheets supplied by Mr. Reising and discovered several problems First, his spreadsheets contain numerous circular references, failed to account for $29 million in revenues associated rate class GL, and allocated $25 million in revenue requirements to Duquesne's only FERC jurisdictional customer (Pitcairn) Circular references can be a particularly nasty problem because they involve a formula that depends either directly or indirectly on its own value The Lotus manual for 1-2-3 Release 5 informs readers that " a circular reference is almost always an error, and you should correct it immediately". (See

Using 1-2-3 release 5 for Windows, Special Edition, 1994, pages 131-133.) While circular references in a spreadsheet sometimes can be deliberate Mr. Reising provided no documentation of the reasons for these circular references and it is therefore unclear to me whether these were intentional. Until Mr. Reising explains whether or to what extent these circular references lead to problems of indeterminacy in results, the Commission can place no confidence on the results from his study. The second problem I found involves his failure to include the billed revenue associated with rate class GL This causes a problem because his cost of service is based on "realized returns" which is dependent on billed revenues. (An approach that I find conceptually flawed as I explain in the next section of my testimony.) Since the realized return is computed by subtracting expenses from actual revenues and then dividing by allocated rate base, his returns are biased downward, and as a result, so are his unbundled delivery service rates. Finally, Mr. Reising shows allocated revenue requirements at Exhibit 2 PDR-3, attached to his testimony These results show revenue requirements of $25,358,000 for FERC jurisdictional customers This is clearly in error because Duquesne serves only one customer at the FERC jurisdiction (Pitcairn) which provided billed revenues of less than $900,000 during 1996. As a consequence, his value of retail revenue requirements is seriously under-estimated. In my opinion, Mr. Reising's study is so flawed that it can not be relied upon at all by the Commission in its adjudication of cost allocation issues in this proceeding.

Q. Would you care to comment on that portion of Mr. Reising's testimony where he

calls upon the Commission to adopt his proposal to set rates that "reflect the characteristics of the customer's service rather than historical identification by traditional class of service"? (See Reising direct pages 25-28)

A. Yes I would Let me begin by saying that Duquesne's rate classes have historically been differentiated on the basis of size, not necessarily voltage service level. While I do not disagree on a conceptual basis with his proposal, I find it completely unreasonable given the Act's prohibition against cost-shifting within and among rate classes. And that would be the effect of his proposal because Duquesne's general service rate classes contain customers served at various voltage levels. As a result, establishing rate classes on the basis of voltage service levels will shift costs from customers served at higher voltage levels to those served at lower voltage levels.

Q. What is the basis for your conclusion?

A. Based on an analysis I have done for rate class GL This class contains customers served at the transmission level (both transformed and untransformed), 23 KV level, and some who receive service below the 23kV subtransmission level Load research data for 1996 indicates that rate class GL had a diversified peak demand of 573,790 kW Of this amount, 558,465 kW remained on the sub-transmission system while 46,415 kW of demand was served at the primary and secondary voltages As a result, certain costs allocated to all customers would be attributable to only a few under Mr. Reising's proposal.

Q. Have you attempted to quantify the cost shifting for this class under the Reising

proposal?

A. Yes I used rate base items included in accounts 364-368 which are allocated by allocator 8(D30 in the last cost of study service) in Duquesne's cost of service study I then made an estimate of the return and O&M expense associated with these items to identify the current allocation of costs to all customers in rate class GL This amount was calculated to be $1.04/kW/year I then allocated the annual revenue requirements associated with these costs to just the load served at the lower voltage levels The resulting cost was $12.88/kW/year - in excess of a 12 fold increase Clearly the Reising proposal would produce significant cost shifting among customers in rate class GL Exhibit JAL-16 summarizes the results of this analysis.

Q. Can you illustrate this problem with a simple numerical example?

A. Yes To do so I will assume that a utility has a system characterized only by plant investment in secondary, primary, and transmission plant and equipment To complete the picture I will attach costs to each type of investment and assume that this company currently serves only two customers in a single rate class. Customer Number 1 is served at the secondary voltage while customer Number 2 is served at the highest voltage level - transmission These data are summarized below:

		ALLOCATED COST OF SERVICE			
CUST. ID	LOAD	SECONDARY	PRIMARY	TRANSMISSON	TOTAL
Number 1	10	$50	$30	$20	$100
Number 2	40	$200	$120	$80	$400
TOTAL	50	$250	$150	$100	$500

Under generally accepted principles of cost allocation, each customer will be responsible for a load ratio share of the total cost of service given the above situation This allocation will result in each customer paying a rate of $10 for each kW of billed demand Under Mr Reising's proposal, rate classes would be established on the basis of voltage service level As such, applying the Reising approach to the above set of numbers would produce a substantially different cost of service allocation as shown below:

		ALLOCATED COST OF SERVICE			
CUST ID	LOAD	SECONDARY	PRIMARY	TRANSMISSION	TOTAL
Number 1	10	$250	$150	$20	$420
Number 2	40	$0	$0	$80	$80
TOTAL	50	$250	$150	$100	$500

In Mr. Reising's world customer Number 1 would be responsible for all the costs of the secondary and primary network and a load ratio share of transmission cost. As a result, his cost of service would rise from $100 to $420. Customer Number 2 will be happy because his allocated share of costs will drop to $80 since he will no longer be responsible for any of the costs associated with the secondary and primary voltage levels since his service only involves the transmission voltage service level. Clearly the Reising proposal involves substantial cost shifting activity among customers within a particular rate class. While the illustration is over simplified, the implications of significant cost shifting among Duquesne customers are real as I have already discussed. The Commission should reject this proposal.

Q. Earlier you said that Enron witness Reising and OSBA witness recommend the use of realized rather than required rates of return for setting unbundled delivery charges. Since Mr. Kalcic explains his rationale for this position, would you describe his objections to the Company's use of a required rate of return, instead of an imputed rate of return to calculate the cost of unbundled distribution and transmission services.

A. Mr. Kalcic asserts that "it is inappropriate to impute a (claimed) system rate of return (9.61%) to the transmission and distribution rate base but only a residual return to the generation". (See Kalcic direct at page 6.) He goes on to argue that the Company's method is the equivalent of a petition to increase distribution rates - an action which is prohibited by the Act until mid-2001". (See Kalcic direct at page 7.)

Q. Would you care to respond?

A. Yes. Mr. Kalcic's proposal would impute the same rate of return to determine unbundled revenue requirements for each functional component of costs. He would use the "realized" imputed rate of return (8.86%) he computes on the basis of 1996 revenue levels. Duquesne prepared its unbundled cost of service study on the basis of its estimated required cost of capital (9.61%). This study produced revenue requirements in excess of its test year revenues. Therefore, consistent with its top down approach and the overall rate cap provision of the Act, Duquesne subtracted the allocated transmission and distribution costs from the rate cap level to determine the recoverable amount of generation-related dollars.

As I explained in my direct testimony, the production component of costs was then broken into its market value and its recoverable portion of above market costs.

Q. Is Duquesne's use of the required cost of capital consistent with other recent regulatory filings?

A. Yes. Duquesne used the required cost of capital to develop rates for the pilot program and the Commission approved transmission and distribution rates based on the cost of service submitted. Duquesne also used the same methodology to develop the rates for transmission and ancillary services that have been filed with FERC.

Q. Why do you believe the Company's approach is consistent with the requirements of the Act.

A. As I explained in my direct testimony, the Commission never approved rates on an unbundled basis. Rather it only approved revenues and rates on a bundled basis. Duquesne designed unbundled transmission and distribution rates on the basis of a 1996 allocated cost of service study using allocations consistent with those used in its last base rate proceeding. There is no basis for Mr. Kalcic's claim that the Company's approach produces results that are prohibited by the Act. Furthermore, Mr. Kalcic's contention that it is inappropriate to provide only "a residual return to generation" ignores the fact that this is precisely what the PaPUC did in Duquesne's last base rate proceeding implicitly allowing a much higher rate of return for transmission and distribution plant than it did for

generation. Not using a higher rate of return in unbundling transmission and distribution costs could be claimed as being inconsistent with the cost of service approved by the Commission in Duquesne's previous base rate proceeding.

Q. Please explain.

A. In Duquesne's last base rate proceeding, the Commission approved an overall rate of return of 10.94%. However, the PaPUC disallowed an equity return for Beaver Valley 2 and the Elrama units. The result of this equity disallowance was to approve revenues that provided for an overall"realized" rate of return of 8.9%. Clearly the implicit rate of return for generation was lower than the realized rate of return since transmission and distribution-related revenue requirements were based on an allowed return of 10.94%, which is 130 basis points higher than the 9.61% used in computing the allocated cost of service study results for this proceeding.

Q. Is there anything else you would like to say on this issue?

A. Yes. Under the Act, distribution and transmission rates will continue to be based on an embedded cost of service basis. It therefore seems logical to me that the unbundled rates approved in this proceeding be set on the same basis Duquesne has proposed and not on the basis of an overall"realized" rate of return as Mr. Kalcic recommends.

IV. RATE DESIGN ISSUES

Q. Several intervenors have criticized Duquesne's proposal to re-design its rates as part of its restructuring proposal. Could you summarize the objections raised against the Company's plan?

A. There is almost unanimous agreement among the intervenors that the rate re-design proposed by Duquesne would result in a shift of costs from growing to declining load customers. MAPSA witness Russell believes the cost-shifting problem to be so severe that it violates the rate cap provisions of the Competition Act. OSBA witness Kalcic and OCA witness Lee Smith have similar concerns over cost shifting but do not appear to find the statutory problem Mr. Russell finds. DIIC witness Baron finds no cost shifting problem when comparing the rate impacts of Duquesne's proposal relative to its current bundled rates at the test year level of sales. However, he goes on to assert that because the Company's proposal recovers a higher proportion of revenues through a fixed CTC, it results in higher customer rates on a "risk adjusted" basis. These "alleged" problems of cost shifting lead them to question the fairness of the Duquesne proposal and recommend against its acceptance. OSBA witness Kalcic acknowledges the "theoretical" efficiency justification for Duquesne's proposal but like OCA witness Smith and Environmentalist witness Shoengold assert that the Company has not provided sufficient support. Mr. Shoengold also complains that energy efficiency programs will be harmed under the proposal since rates for incremental

usage will be substantially lower than they are under current bundled rates. Finally, Mr. Russell (MAPSA) and Ms. Smith (OCA) express concerns over customer acceptance.

Q. Would you care to make some general observations before you respond to these specific criticisms?

A. Yes. Given the numerous complaints about the high level of retail rates in Pennsylvania I am truly amazed by the negative reaction this proposal engendered. The Duquesne proposal embodies a rate cut of up to 50% for incremental usage which: is revenue neutral, increases consumer welfare, and facilitates stranded cost mitigation (as the Competition Act requires), thereby shortening the CTC recovery period. In short, a proposal with the potential of benefiting everyone and harming no one. It is understandable why some might oppose a rate design proposal that improves efficiency at the expense of fairness or adequacy. It is inconceivable why anyone would oppose improved efficiency where neither is sacrificed. Intervenor claims notwithstanding, Duquesne's proposal will bring rates closer to market prices raising the same amount of revenue as the current bundled rates at the test year level of sales. And it will do so without shifting costs from one rate class to another. Indeed, since the Company's proposal uses customer-specific transition charges to recover above market costs, it meets the most stringent test of fairness: it prevents cost shifting among individual customers. The intervenor witnesses confuse issues of cost shifting (which the Act prohibits) with revenue shifting (which occurs normally

between rate periods under any rate design proposal).

Q. Would you turn to the specific criticisms offered by the intervenor witnesses?

A. I will begin by addressing cost shifting and the related issue of fairness and then conclude by discussing the aspect of efficiency. As I have already said, almost all of the witnesses discussing rate design argue that the Duquesne proposal should be rejected because it would involve a shifting of stranded cost responsibility. (See OCA witness Lee Smith at page 8.) DIIC witness Baron, recognizes correctly that "specific costs have not been explicitly shifted under the Company's proposal" although he goes on to reject the proposal because it increases the "take-or-pay obligations" of the customer. (See Baron direct at page 52.) Even MAPSA's witness Russell concedes this point by correctly pointing out that customer charges under the re-design proposal are the same as they otherwise would be under current rates when measured at the baseline level of sales. (However, he then uses this observation to conclude that Duquesne's proposal will not be in compliance with the Act if a customer's usage declines between 1996 and 1999.) OSBA witness Kalcic and OCA witness Lee Smith are less precise in their concerns than either Russell or Baron, but both raise cost shifting concerns with the Company's proposal. All of the witnesses miss the mark by confusing cost shifting with changes in revenue recovery over time. (Apparently the term cost shifting is used so often in an attempt to imply than the Duquesne proposal is inconsistent with the Competition Act.)

Q. I take it that you disagree with those who contend that Duquesne's proposal will

shift costs.

A. Yes I do. I disagree because the "top down approach" used by the Company to compute customer-specific CTCs is premised on maintaining an equivalency between bundled and unbundled revenues. As I explained in my direct testimony, the Company's approach to unbundling insures that no customer pays more in total (for the sum of his unbundled rate components assuming power is purchased at the CGC rate) than he would have paid under current bundled tariffs at the test or base year level of sales. This is a basic arithmetic identity of the top down approach in general and the Duquesne proposal here. (Revenue neutrality is demonstrated in Exhibit JAL-4 attached to my direct testimony.) Moreover, unlike top down approaches proposed elsewhere (California and New York) which maintain revenue neutrality between bundled and unbundled rates on a class specific basis, Duquesne's approach maintains revenue neutrality on a customer specific basis. Since there is no shifting of revenues at the base year level of sales there can be no cost shifting. This test of cost shifting is a traditional measure used by regulatory jurisdictions since time immemorial to compare the cost shifting implications of alternative rate designs. Rate design alternatives are always assessed on the basis of **test year sales** to insure that each alternative recovers the same overall level of revenues, and to see whether there is cost shifting across classes and finally to determine individual customer impacts within a particular rate class. Often times a more efficient rate design proposal will be rejected because of unacceptable customer bill impacts. Duquesne's

proposal will lead to more efficient prices for incremental use without any cost shifting trade-off at the class or individual customer level.

Q. I think I understand your point as it relates to test year sales, but wouldn't you concede that the intervenors have a point when they say that costs will be shifted from growing to static or declining load customers?

A. Absolutely not. What Mr. Kalcic and the other witnesses miss is the fact that customers with growing load will contribute a higher not lower percentage of overall revenues. More importantly, since the prices for incremental usage are set above the sum of market power prices and the marginal cost of delivery service, these customers will cover all costs associated with their incremental consumption **plus** provide a contribution towards fixed cost recovery. These additional margins to accelerate the write-down of stranded costs will benefit all customers with the Company's proposed "spill-over" mechanism.

Q. Can you provide an illustration?

A. I will even though the conclusion seems obvious from what I have just said. First, assume a utility has an existing rate schedule that is comprised of a fixed monthly charge of $10 and energy charge of 10¢/kWh. I will also assume that this utility has just two customers: RS1 (a low use customer whose usage will decline given current rates) and RS2 (a high use customer whose usage will grow given current rates). The existing rate schedule will recover $1,940, at the base year sales level, as shown in the table below. This table also shows revenue recovery given assumed future usage levels. Note that these changes in usage are totally

unrelated to any change in prices.

REVENUE RECOVERY UNDER EXISTING RATES					
Customer	Base kWh	Revenues		Future kWh	Revenues
RS1	5,000	$620		4,750	$595
RS2	12,000	$1,320		12,500	$1,370
Total	17,000	$1,940		17,250	$1,965

As shown, in the future period RS1 uses 250 kWh less and saves at the rate of 10¢/kWh resulting in annual savings of $25. On the other hand, RS2 increases usage by 500 kWh and will see his bill rise $25 per year. (Note that the average revenue per kWh will rise for RS1 from 12.4 ¢/kWh to 12.5 ¢/kWh and fall for RS2 from 11.0 ¢/kWh to 10.9 ¢/kWh even under the existing rate structure because of the fixed monthly charge. Following the intervenors' logic, one could argue that the existing rate design violates the rate cap provision of the Act.) Now I will assume that the existing rate structure is re-designed by increasing the fixed charge rate portion and reducing the energy charge to 6.0 ¢/kWh. The fixed charges will be set so that each customer has the same total bill each paid under the existing rates measured at their respective base consumption levels. Under this alternative: RS1 will pay a monthly charge of $26.67 while RS2 will pay a monthly fixed charge of $50 (This is the essence of Duquesne's rate re-design proposal.) The future sales levels will be different than those assumed under the existing rate structure given consumer response to a 40% reduction in their price for incremental consumption. In the table below, I have assumed that the elasticity effect is .10, which means that customers will increase consumption by about 4% given a 40% drop in the energy charge.

BASE AND FUTURE REVENUES WITH RATE RE-DESIGN					
Customer	Base kWh	Revenues		Future kWh	Revenues
RS1	5,000	$620		4,950	$617
RS2	12,000	$1,320		13,000	$1,380
Total	17,000	$1,940		17,950	$1,997

First, it should be pointed out that the alternative rate design recovers the same level of revenues as existing rates for the base consumption levels and $32 more revenues in the future period. Also, notice that customer RS1 reduces his consumption less than he does under the existing rate, while RS2 increases his consumption more. This is the result of providing each customer lower usage rates. In other words, the elasticity-induced effects from the re-design in rates encourage more usage from **both** customers providing welfare gains. Provided that the incremental cost is less than the marginal energy price, society and customers are better of from more efficient pricing signals and accelerated stranded cost mitigation.

Q. How do you respond to the intervenor witnesses who contend that Duquesne has not demonstrated its claimed efficiency benefits from its rate re-design?

A. As I explained in my direct testimony, Duquesne's current rates far exceed the incremental cost of additional consumption. With current power prices below 2.0 ¢/kWh and marginal distribution and transmission losses of 20% (double the average losses at the secondary level) to serve customers at the secondary voltage level, purely efficient prices would be set at levels approaching 2.4 ¢/kWh. For no rate class does Duquesne propose tariffs (i.e., the sum of transmission, distribution, variable CTC, and CGC) anywhere near this level. For the RH class,

the lowest proposed charge is during the off-peak period (for usage in excess of 500 kWh per month the combined price is set at 4.49 ¢/kWh). There is clearly no support for the intervenors' arguments that Duquesne is proposing usage-based prices that are below marginal cost.

Q. Will Duquesne modify its proposed rate design proposal to allow customers the option of a simple unbundled rate design structure?

A. Yes. Duquesne will adopt the proposal set forth by OSBA witness Kalcic to allow customers the choice of Duquesne's rate re-design or a simple unbundled rate structure. Offering customers the option of a simple unbundled tariff should put to rest any intervenor concerns over the fairness of Duquesne's rate re-design proposal.

Q. Does this conclude your testimony?

A. Yes, it does.

Other Rebuttal Issues By Witness

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Weisenmiller – Direct (HSS1)	26	8-21	RFP Market Definition	The current RFP reflects market prices only for the Company's region and service area. Future prices will be determined by the clearing price in the region as a whole. The current RFP prices are therefore deceptive.	The point is that the one-year RFP represents Duquesne's opportunity cost – the price it can achieve in the wholesale power market today. If that market changes during the transition period, the RFPs conducted in those years will reflect market clearing prices at that time. Finally, the eight-year RFP should not be an issue because it is not being used to set a one-time determination of stranded costs.
	30	7-19	RFP Contract Terms	The structure of the RFP was not conducive to estimating an accurate market price estimate. The inflexible nature of the contract durations limited the number of interested respondents.	Dr. Weisenmiller fails to acknowledge that Duquesne solicited comments on the RFP and adopted a significant change (regarding transmission constraints) when it was appropriate to do so. This process can be continued in future solicitations. Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value, something Dr. Weisenmiller seems uninterested in pursuing. Finally, these arguments do not justify rejection of a market-based RFP process, which is superior to picking an estimate from a multitude of expert opinions.
	32	6-14	RFP Delivery Costs	The final prices are misleading because they do not include the costs of delivering the power. "Under the RFP, purchasers were required to secure transmission service over the Company transmission system".	The RFP prices are adjusted in setting the CGC for retail delivery costs that will be incurred by suppliers. For the 8-year sale of power, however, this adjustment is not necessary: it is used to calculate market clearing prices, not customer generation credits.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	33	8-14	Wholesale RFP Relevance	Since the RFPs were for wholesale power only, this power is only valuable to independent merchants after a competitive market exists for retail customers.	This is not true. There is no impediment to purchasers using this power to serve retail load in Duquesne's pilot. In any event, Duquesne will conduct future solicitations concurrent with retail choice in its service territory.
	34	16-18	Transmission and RFP Price	Because of the uncertainty in paying 'pancaked' transmission access charges, bidders would have offered lower prices.	Dr. Weisenmiller fails to understand that elimination of pancaked rates will have a downward effect on market prices, all other things being equal.
	35	15-21	RFP Transmission Uncertainty	Because the physical limitations of the system will not change, delivery of the power, even after payment for transmission access, is not assured. "These uncertainties would further depress the bids."	This argument is without merit. There is no evidence that a supplier would not be able to purchase firm transmission on Duquesne's system, if so desired. Moreover, Section 6 of the PSA was amended, at the request of suppliers, to eliminate the risk of transmission curtailments on Duquesne's system. These risks are borne by Duquesne. Dr. Weisenmiller concedes this point in his interrogatory response # 28, Set I.
Weisenmiller Interrogatories Set I (HSSI)	1-2	Response 12	RFP Contract Terms	The RFP produces a distorted measure of real market value of electric generation. He suggests that the purchaser should be able to specify the conditions of the contract.	First, the RFP product terms and procedures could be modified in future solicitations. Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value. These arguments do not justify rejection of a market-based RFP process. Second, the purpose of the RFP is to establish a known and measurable market price to establish market-based CTCs and CGCs. Allowing each bidder to specify and bid on different products would complicate the RFP evaluation process without increasing prices. For example, the bidders that did submit bids conditional on changes in terms and conditions had price quotes lower than the winning bidders.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	1	Response 13	Valuation Based on Output from an Asset	Market valuation based on an agreement to sell the output of an asset is possible, although other factors are likely to come into play, such as strategic premiums.	First, Dr. Weisenmiller fails to detail what is meant by strategic premiums associated with asset sales. It is especially unclear what this strategic premium might be for Duquesne's remaining assets, particularly those units which Duquesne does not have operational control. Second, Dr. Weisenmiller contends that the market value of all Duquesne's assets should be set on the basis of the value received from the Ft. Martin sale. This assertion is not credible and is in direct contrast to his deposition. There, he admits that the sale of one fossil unit does not set the value for the remaining fossil units (much less the nuclear units). (pp. 5-6)
	1	Response 14	Relevant Market	To calculate a value for Duquesne's generating assets, the relevant price would be the highest price that Duquesne could get for that power.	Duquesne agrees that it should be based on what Duquesne could actually get for that power. The primary purpose of the RFP was to establish that value.
	1-3	Response 20	RFP Contract Terms	By establishing a series of off-putting, seemingly hard-and-fast rules, Duquesne effectively could have screened out other, potentially higher bidding, buyers.	First, the RFP product terms and procedures could be modified in future solicitations. Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value. These arguments do not justify rejection of a market-based RFP process. Second, the purpose of the RFP is to establish a known and measurable market price to establish market-based CTCs and CGCs. Allowing each bidder to specify and bid on different products would complicate the RFP evaluation process. Thus, as indicated by Mr. Marshall, Duquesne is willing to submit the RFP in advance to the Commission for prior approval. Finally, Dr. Weisenmiller ignores the fact that not a single marketer indicated to Duquesne that it was not submitting a bid because it could not set its own terms.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	1	Response 30	Accurate Measures of Market Price	Dr. Weisenmiller supports asset divestiture. He argues that if Duquesne is unwilling to sell more assets the sale of Fort Martin should be used. He also acknowledges that published price indices can be a valid measure of market prices, but are not readily available for Duquesne's service area.	First, as Mr. Marshall testifies, Duquesne will, if the Commission deems it appropriate, divest all its generating units in the year 2003 to establish a final valuation for those assets. Second, as Mr. Clayton testifies, Dr. Weisenmiller's recommendation to use Fort Martin as the basis for evaluating other Duquesne assets is meritless and inconsistent with his position taken in his deposition. (pp. 5-6) There, he recognizes that the sale of one asset is not necessarily a good indicator of the value of other assets. Finally, Duquesne relied on the market-based RFP process absent a valid market price index today. Once markets evolve, Duquesne would be willing to use a forward contract to establish the annual CGC and CTC.
	1	Response 33	RFP Take or Pay Requirement	The take or pay provision is viewed as an additional risk that causes buyers to bid down the price.	The annual RFP is being used to value the output from Duquesne's generating assets. Therefore, the terms of the sale need to reflect the characteristics of the Duquesne system. First, the 50% minimum take is consistent with the operational constraints faced by Duquesne during minimum load periods. Second, Duquesne's generation portfolio is comprised primarily of baseload units and a 75% capacity factor is appropriate. The RFP power was fully dispatchable within 50% and 100% of the contract amount. Finally, the annual capacity factor requirement is necessary in order to establish a known and measurable contract quantity and market price. As noted above, Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value, and the Company is willing to submit the RFP to the Commission for prior approval.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	1	Response 35	Relevant Market	To assume that the price for a purchase in Duquesne's service territory, which is at one side of ECAR, is representative of the market-clearing price for all of ECAR is incorrect.	The primary purpose of the RFP was to establish the market value of Duquesne's generation based on what Duquesne could actually get paid for that power. This is consistent with Dr. Weisenmiller's response to interrogatory #14, Set I.
Russell—Direct (MAPSA)	19-21	19:11-21:34	Ancillary Service	The Company should add the ancillary charges which the Company charges itself to the credit for ancillary services given to customers for revenues collected from suppliers.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires services (i.e., transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	22-23	22:8-23:20	Evidence of Market Prices	*Power Markets Week* in Mr. Lahtinen's testimony shows ECAR and PJM prices above the Company's RFP results of 18 mill per kWh, revealing the value of APS transmission facilities.	This is untrue. The prices reported in Power Markets Week support both the prices obtained in Duquesne's RFP and the differences between ECAR and PJM. According to the editors of Power Markets Week, the publication conducts confidential surveys of buyers and sellers of the prices charged in wholesale power transactions in different regions. Using this information, Power Markets Week constructs a weekly weighted average power price index for peak periods and a weekly price range for off peak periods for several regions of the country, including ECAR and PJM. The weighted average market price of power in ECAR shown in my direct testimony was below $0.02/kWh ($20/MWH) in both 1997 and 1996, and for the year 1996 it was approximately $18/MWH. (p.76) That data is consistent with the prices resulting from the RFP and Duquesne's system lambda data, both of which are around $18/MWH. The Power Markets Week data also confirms the proposition that power prices in PJM tend to be materially higher than in ECAR. The "value" of APS transmission facilities to which Mr. Weisenmiller refers is undefined and, in any event, irrelevant to this case.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	23-24	23:21-24:26	Market Value for Capacity	PJM value of capacity for a deficient member is $56 per kW-yr, which translates to 13 mills per kWh before necessary adjustments. Moreover, the Company's sales indicate the value of capacity from $42-$52 per kWh-yr. Capacity value should eventually approach the long run equilibrium price of $87 per kW-yr.	First, the value of capacity in ECAR is significantly below these levels. Mr. Irvin's direct testimony indicated peak capacity value ranging between $0.43 per kW-yr to $1.06 per kW-yr during 1996 and 1997. This data comes from actual prices Duquesne paid for the rights to call upon capacity. It should also be pointed out that these prices represent capacity value during Duquesne's summer peak period, indicating similar purchases of capacity during lighter demand could be obtained at lower prices. As a result, the effective annual price for peaking capacity is likely to be even lower than indicated by the above figures. Second, Mr. Russell conceded in deposition that the PJM market tends to be different than the ECAR market. (p.61) Therefore the value of capacity in PJM is not relevant to this case since Duquesne is in ECAR. In any event, the power sold in the RFP is firm and already includes the value of capacity. Therefore, no additional adjustment is necessary.
	25	1-17	Use of a Wholesale RFP	The RFP will not provide a representative price. Sales to wholesalers with a myriad of sources to serve load have been historically lower than sales to those with fewer options to supply load. The buyer and seller also need not concern themselves with the load shape of the user, or the statutory requirement to serve load, which will also depress the price.	First, the RFP price represents the best measure of Duquesne's opportunity cost of serving retail load – the price it can achieve in the wholesale power market. Second, Duquesne has made adjustments for retail customer load shapes. Third, retail customers will have the same options in 1999 as wholesale customers do today.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	25-29	25:18-29:	RFP Contract Terms and Procedures	The RFP will produce low bids. The 75% capacity factor is high, higher even than the Company's average. The RFP requires scheduling of 50% at all hours, and the Company is not required to deliver above the 75% take or pay amount, which decreases flexibility. No guarantee is made the winner will obtain the MW block of power which was bid (min. of 10 MW only) and limited time was given to respond to the RFP.	First, Duquesne is willing to consider any reasonable suggestions to adjust contract terms and procedures that increase market value. These arguments do not justify rejection of a market-based RFP process, which is superior to picking an estimate from a multitude of expert opinions. Mr. Russell seems content to regrettably, "throw rocks" at the RFP, rather than offer constructive comments. Second, Mr. Russell conceded in deposition that the best way to set the CGC is to use public indices of market clearing prices. (pp. 35-36, 67) Today, the RFP is the best such index. To the extent that other market-based solutions evolve in the future, Duquesne would consider them. Third, RFP power was fully dispatchable within 50% and 100% of the contract amount. Fourth, the 50% minimum is consistent with the operational constraints faced by Duquesne during minimum load periods. Finally, Mr. Irvin informs me that these provisions did not cause any problems with suppliers.
	27-28	27:32-28:25	RFP Panel and Adjustments	A disinterested panel such as the Commission should administer the RFP, and the results should be adjusted for capacity cost, load factor of retail loads, ancillary services, and other costs.	As indicated by Mr. Marshall, Duquesne is willing to submit the RFP in advance to the Commission for prior approval. The "proper" adjustments to RFP prices are addressed in the main testimony.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	29-32	29:4-32:13	Setting the CGC Based on Long Run Marginal Costs	CGC should be set administratively based on the long run marginal cost.	This will create new stranded costs during the transition period. When retail load chooses another supplier, Duquesne will not be able to sell excess generation at long-run marginal cost, especially in the near term. (See Mr. Schnitzer's testimony) It is undisputed that market-clearing prices today are far below long run marginal costs. Mr. Russell himself conceded in deposition that ECAR has excess capacity. (p.16) Furthermore, Mr. Russell states he would not expect prices to tighten or rise until you get toward the end of the transition period. (pp.28-29) Finally, Mr. Russell acknowledges that he is unable to forecast market prices with any certainty and in his response to interrogatory 27, he states that he "is unsure and is anxiously awaiting the results of a competitive market to determine this." (Interrogatories, set 1, p.14) The Commission should reject administratively setting the CGC based on long run marginal costs and avoid the creation of new stranded costs.
	32-37	32:15-37:18	Using Market Indices and Adders for the CGC	If the long run marginal cost is not accepted, various market indices could be used for the CGC which would need to have the following adders: capacity, installed reserves, ancillary services, marketing and overhead, losses, and profit.	These "adders" are addressed in the main testimony.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	37-40	37:20-40:31	Customer Specific CTC	The Company's CTC proposal should be rejected. The CTC does not comply with the rate cap. The process is confusing, burdensome to implement, and would hamper competition. Also, the CTC is really premise specific, which is not appropriate.	First, the customer-specific CTCs are in full compliance with the rate cap and prevent cost shifting. For those customers who continue to purchase electricity from Duquesne, the unbundled rates will result in the same bill the customer would otherwise pay under bundled rates assuming test year 1996 sales. Second, the resulting efficiency and stranded cost mitigation benefits far exceed any implementation hurdles. None of the intervenors made any substantive criticisms of the resulting efficiency gains and potential stranded cost mitigation that I have provided in my direct testimony. There I estimated that the proposed rate redesign provides an opportunity to further mitigate stranded costs by approximately $15 million per year or more. The restructuring legislation orders utilities to fully mitigate stranded costs and rate re-design affords Duquesne one of the best opportunities to do so. Stranded cost mitigation benefits all consumers and not just those who increase consumption. Finally, Duquesne proposes to give customers the option to choose between the current and the proposed rate design. This allows customers to decide which option is best for them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	54-55	54:1-55:27	Customer Participation Credit (CPC)	CPC should be set at same level as in the pilot to foster competition. Even though the pilot was oversubscribed, this level may not provide robust competition.	First, this will create new stranded costs during the transition period. (See Mr. Schnitzer's testimony) The purpose of the transition period is to mitigate stranded costs, not create new ones that would have to be dealt with at a later time. Mr. Russell's position is the exact opposite. He proposes to set the CGC on the high side with adders and a CPC and "keep track of the extent to which the utility's amortization of stranded costs is penalized or hurt." He goes on to recommend that the Commission allow utilities to recover these additional stranded costs and suggests a possible extension of the transition period. (Russell deposition, pp. 11-13) Duquesne, on the other hand, proposes to mitigate stranded costs during the transition period as quickly as possible. Critical to Duquesne's approach is the establishment of CGCs that reflect the market value of its generation. Second, the need for such a credit is not based on any market evidence. Mr. Russell concedes in deposition that it is "just carried over from the retail pilot" (p.41) Mr. Russell has no opinion about what prices will be, but nonetheless, recommends that whatever the CGC is set at initially, it should be marked up for a 13% customer participation credit. I find little comfort in Mr. Russell's deposition where he states that "it's not exactly a self-serving recommendation from the point of view of the suppliers." (p.42) It is quite clear that many of the intervenors would prefer that Duquesne be required to set a high CGC as opposed to a market-based one, since customers would have a greater incentive to switch to an alternate supplier and/or suppliers would have a greater opportunity to make a profit.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Russell—Interrogatories Set 1 (MAPSA)	1	Response 1	Estimating Market Prices	The market price in a competitive environment cannot be known beforehand. It can only be known after the fact.	First, Mr. Russell seems not to understand markets. A one-year forward sale does establish a market price for that product and that term. Because of this, the proposed annual RFP will reflect market conditions and expectations at the time when customers choose retail access. As the market changes during the transition period, the RFPs conducted in those years will reflect market-clearing prices at that time. Mr. Russell, has few practical solutions other than to set the CGC on the high side based on long run marginal costs. His solution ignores reality – the fact that current market prices are significantly below long run marginal costs.
	3	Response 4	RFP Contract Terms	Mr. Russell did not testify that terms should be deleted, added or changed in the Duquesne RFP.	Mr. Russell claims that Duquesne's RFP terms yield biased low prices, but when asked how he might alter the solicitation, he fails to propose any practical solutions to establish a market-based price that is known and measurable.
	11	Response 18	Excess Capacity in ECAR	Mr. Russell agrees with Duquesne's position that there is excess capacity in ECAR.	While Mr. Russell agrees that there is excess capacity in ECAR, he argues that the CGC should be based on the cost of adding new capacity. His recommendation should be denied since by his own admission, his proposal fails to reflect market conditions.
	12	Response 22	Market Prices in ECAR vs. PJM	Mr. Russell states that there is a material difference between market clearing prices in ECAR and PJM.	Duquesne agrees and CGCs established in these markets should reflect these differences.
	12	Response 23	Relevance of PJM Capacity Prices	To the extent that Duquesne can obtain capacity to the border with PJM, its capacity should be valued at the capacity value within PJM.	This is incorrect. The value of capacity in ECAR is determined by supply and demand in ECAR taking into account import and export limitations.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	14	Response 28	Firmness of RFP	Mr. Russell asserts that the RFP process sampled "non-firm" power.	This is incorrect. First, the power that is provided under the RFP is a firm obligation to sell electricity backed up by Duquesne's financial obligation to pay replacement costs if Duquesne fails to perform. The bottom line is that Duquesne will physically provide the power or pay the supplier replacement costs. The RFP purchaser therefore is held harmless. Therefore, this sale is not akin to a spot or non-firm sale of power into a power exchange as Mr. Russell asserts. I suspect that the real objection Mr. Russell and others have with the RFP price is that the "market" doesn't place as much value on firm power as these "experts" would like. The fact that capacity has little or no value in the ECAR region is a reality that everyone, most of all Mr. Russell, wants to ignore in this proceeding. Second, Duquesne provided additional evidence in this case on the capacity value of generation within the ECAR region that supports the results from the RFP. That data based on actual prices Duquesne paid for the rights to call upon capacity indicated a peak capacity value ranging from $0.43 per kW-yr to $1.06 per kW-yr during 1996 and 1997. These prices represent the capacity value during Duquesne's summer peak period, indicating that similar purchases of reserved capacity during times of lighter demand could be obtained at lower prices.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	16	Response 32	Adjustments to CGC	Mr. Russell advocates that the CGC rate beyond 1999 be adjusted by the prices experienced in the marketplace and known and measurable changes to the markets.	Duquesne has attempted to set the CGC and proposes to adjust it based on prices experienced in the marketplace and known and measurable changes to the markets. The primary difference is that Duquesne is relying on a contemporaneous wholesale RFP as an index, whereas, Mr. Russell wishes to rely on a historical retail index. His suggestion is not as simple as it sounds. He fails to describe the terms of the retail sale, whether or not a standard retail product would be chosen, how historical prices would reflect expectations about the future, how retail prices would be recorded, and so forth. In essence, he is proposing a continuous, eight-year litigation schedule to predict and true-up CGCs.
	16	Response 34	RFP Capacity Factor	Mr. Russell is unable to specify the capacity factor that would have optimized the value of the RFP power.	Mr. Russell is unable to provide constructive suggestions with respect to a market-based RFP valuation. He claims the RFP yields a low value, but cannot "fix" it.
	18-19	Response 38	RFP Contract Terms and Take Flexibility	Mr. Russell does not advocate a fine tuning of the RFP but its total abandonment.	Again, Mr. Russell presents no practical solutions for establishing a known and measurable market-based price.
	19-20	Response 39	Load Following and Balancing Services in RFP	"It is the duty of the proposer to design an appropriate RFP."	When asked how he would resolve his own criticisms of the RFP, Mr. Russell is unable or unwilling to comment. While Mr. Russell talks about wanting to see markets set prices, he relies on an administrative market price estimate, which according to his responses regarding excess capacity in ECAR, fail to reflect current market conditions.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	25-26	Response 53	High CGC for Competitors to Recoup Their Costs	Mr. Russell argues for setting a high CGC so that MAPSA suppliers can recoup all their generating costs in competitive markets.	Mr. Russell recommends the use of long run marginal costs or indices with a variety of adders including supplier profit margins to set the CGC. However, according to this interrogatory response he has not been provided any data from MAPSA regarding the cost of serving retail customers on which to base his recommendations. His recommendations for the CGC therefore should be rejected since they are not based on any evidence. Furthermore, Duquesne does not believe that it is appropriate to establish the CGC based on suppliers' costs. Prices should be determined by the competitive market and not some administrative cost-plus estimation process. As noted earlier, a biased high CGC would likely result in a new category of stranded costs during the transition period.
Yarolin (OTS 3)	9	1-18	Unbundling Distribution	The Company did not unbundle distribution components such as metering, Universal Service Charge, billing, and service drop lines.	The Company's proposal to include these charges in bundled distribution charges is consistent with recent proposed rulemakings regarding customer information disclosure and advanced metering in Pennsylvania. (See rebuttal testimonies of Mr. Flynn and Mr. Allison)
	10	16-17	Unbundling Demand Side Management and social costs.	These costs are not solely related to distribution charges and should be separately stated on the bill.	This continues to be a regulated distribution activity under the PUC direction.
Schoengold (Environ-mentalists 1)	10-11	10:27-11:7	CTC True-up	"...it is not clear whether The Company intends to true up the CTC collection to reflect changes in sales levels. If there are going to be true-ups, these true-ups should adjust for both market price and sales uncertainty."	As market prices change each year, Duquesne's CTC will also change. Changes in sales that impact CTC revenues and Company earnings will be taken into account in the ROE spillover mechanism. (See Mr. Clayton's testimony)

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	11-12	11:10-12:14	RFP Price	"Since the annual power sale will be for only a portion of the Company's power, it is not clear how well the sale price will reflect the overall market price."	If the Company sold more power in the RFP, the weighted average winning bid price would likely be lower. In any event, the amount sold represents Duquesne's opportunity cost as retail load selects alternative suppliers.
	11-12	11:10-12:14	RFP Price	"Since the power sale will take place in the context of a mixed competitive/regulated market, it is unlikely that the price will accurately reflect a true market price."	The RFP price represents Duquesne's opportunity cost as retail load leaves. As competition is phased in, Duquesne will continue to issue RFPs each year.
	11-12	11:10-12:14	RFP Price	"As long as buyers and sellers in the marketplace are receiving stranded cost recovery in a regulated setting, it is likely that the market price will be artificially low."	This is not correct. Sales and purchase offers will be determined by supply and demand. In today's markets with excess capacity, prices are driven toward short-run marginal costs.
	13	10-17	High Market Price	A higher initial market price estimate would bring more suppliers into the market and establish a lower CTC. Even if corrected by a true-up, it would induce more realistic market prices.	Biased high market price estimates will create a new category of stranded costs during the transition period.
	16	4-9	Rate Relief	There is no rate relief for customers under the restructuring plan. There are unlikely to see any benefit from competition.	Duquesne has significantly reduced rates on incremental consumption. Residential customers will receive a marginal rate reduction of 50%.
	24	18-22	New Rate Design	With regard to the customer rate, there is a shift from volume-based charges to fixed customer charges. It is simply a rate redesign that should be rejected.	Duquesne's rate design could mitigate stranded costs by $15 million or more annually. The Act requires utilities to fully mitigate stranded costs and rate design is one of the best opportunities to do so.
	24-25	24:24-25:6	Justification for Rate Redesign	Rate redesigns are typically the result of very extensive studies that justify the change. There is no evidence of any in depth study or logic that would justify this change.	Duquesne has submitted extensive analysis and testimony supporting its rate design. Principles of economic theory and pricing also strongly support the efficiency benefits of moving usage charges closer to market levels.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	25	11-25	New Rate Design	"Each customer will have a different rate structure, causing problems with fairness and comparability."	The customer-specific CTCs results in no bill impacts or cost-shifting based on test year sales.
	25	11-25	New Rate Design	"There will be negative environmental impacts from increased air pollution resulting from the promotional character of the new rate design."	More efficient market-based pricing will result in significant benefits. One of the primary purposes of moving toward competition is to eventually lower electricity prices. The proposed rate design does this for incremental consumption.
	25	11-25	New Rate Design	"The new rate design undermines efforts to promote energy efficiency and customer-owned renewable resources."	The new rate design increases efficiency and promotes more economic load management and distributed generation activities.
	25	11-25	New Rate Design	"The new rate design undermines efforts to reduce inefficient use of energy in low-income households with older, less efficient appliances."	The new rate design sends customers more efficient price signals and encourages more economic behavior. The efficiency gains potentially are large and will benefit all customers.
	25-26	25:29-26:4	Rate Cap and Rate Adjustment	It appears that the Company would be able to adjust rates so that the rate for the present level of usage could be increased.	The Company already responded to this concern during interrogatories and has no intention of this. Further, he is inconsistent when he states that the Company has provided no rate relief, while at the same time he is concerned that we could later raise rates under the rate cap.
Baron (DII 1)	24-26	24:14-26:4	Certainty of CTC	Finally, no customer would enter into a contract for longer than one year since there is no certainty in the level of the CTC. The Company should provide the level of certainty other Pennsylvania utilities are proposing.	Duquesne did propose a fixed CTC for the entire transition period in its pilot based on a long-term RFP. In any event, the statement is not correct. In California, they are backing out of rates a monthly power exchange price and adjusting the CTC, yet suppliers and customers will certainly be willing to offer/purchase longer term products.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	37-38	37:4-38:18	DII's Unbundling: Ancillary Services	The $18M was removed from transmission rates, and the costs for reactive supply and voltage control were added to the generation rate. Spinning reserve and other ancillary services are captured in a 15% margin adder to capacity costs in generation prices.	First, Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them. Second, the RFP price includes the value of capacity and installed reserves and no adjustment is necessary.
	38-41	38:4-41:12	DII's Unbundling: Losses	Costs are switched back from distribution rates to generation rates. The company actually keeps these costs in generation for customers who continue to take generation from the Company. Losses should also be at market prices, not embedded costs. Finally, the shift of these costs to distribution is in violation of the Act.	The Company has agreed to remove distribution losses from distribution and increase the CGC credit. Distribution losses will now either be charged to suppliers or competitively supplied.
	42-45	42:18-45:2	DII's Unbundling: Market Price	Hourly marginal costs and annual capacity costs are calculated for on- and off-peak hours. A weighted average is used in unbundling calculations. Where no demand charge is included in a class tariff, the capacity revenue requirements are unitized by total kWh sales.	Duquesne's methodology is similar but more sophisticated. The CGC is based on *hourly* customer load patterns for each rate class and market price data based on the RFP price level and 1996 lambda price shape. The RFP includes the value of capacity costs and installed reserves.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	45-47	45:4-17:15	DII's Unbundling: Rate Schedules	It would be inconsistent to vary the market price and CTC when the stranded cost estimate would not be adjusted as well. Since the stranded cost calculation will not be modified, it is not appropriate to modify the elements of the unbundled rate for any of the transition years.	Duquesne does not propose to lock in stranded costs based on a one-time estimate of market prices. Duquesne does propose to modify stranded costs in the future in the second stage valuation. This argument is invalid.
	48-53	48:1-53:5	The Company's "Fixed" CTC	The CTC rate design equates to a fixed charge for 54% on the monthly bill, which shifts additional risks to customers. On a risk adjusted basis, customers will pay more than under bundled rates.	The Duquesne rate design embodies a rate cut of up to 50% for incremental usage which is revenue neutral, increases consumer welfare, and facilitates stranded cost mitigation, as the Competition Act requires.
	57-58	57:10-58:7	HVPS and "Generation Avoidance"	The Company's proposal does not include a provision for generation avoidance in HVPS. This is a violation of the Act which does not allow elimination of tariffs.	The Company will modify its tariffs to include this provision.
	59-60	59:9-60:7	Transmission Rate Design	If a large customer wishes to access transmission service rates under FERC 888, the T&D rate cap would not be expected to apply to any additional ancillary services. However, if a customer chooses alternative generation supplier, then at least for the 54 months, no additional ancillary services should apply since they are already in the base rate and this would violate the rate cap.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Kahal (OCA 1)	9	21-23	Rate Cap	The rates will not actually remain capped. The will remain constant after a rate increase of roughly 2%.	The Act allows utilities to accelerate amortization to mitigate transition and stranded costs under section 2804 (4)(v). The ECR adjustment is cost-justified and equal to the cap approved by the Commission.
	12	10-13	Rate Increase	The Company already has one of the highest residential rates. It should not be increased further.	(See answer above.) Also, Duquesne has significantly reduced rates on incremental consumption. Residential customers will receive a marginal rate reduction of 50%.
Smith (OCA 4)	2	15-19	Unbundling generation costs	The Company's definition of generation costs excludes line losses and a portion of the generation assets. This assumes in a restructured industry, the Company will retain monopoly control over a portion of the generation services.	The Company has agreed to remove distribution losses from distribution and increase the CGC credit. Distribution losses will now either be charged to suppliers or competitively supplied.
	3-4	3:18-4:16	Inclusion of ancillary service costs with transmission and stranded costs	These services are actually provided by generating units. As such, they will result in revenues going to owners of generation. If the Company does not attribute these revenues to generation, stranded costs will be over-stated.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	4-5	4:19-5:4	Customer's Paying Twice	Since the need for capacity is determined by load plus reserves, there is a reflection of reserve capacity in Mr. Doug Smith's market price. Therefore, the market price estimates result in customers paying for generation ancillary services, so including them again in transmission rates would result in customer's paying twice. Ms. Lee Smith removed the Company adjustment which moves ancillary costs to transmission.	First, it is not correct that customers would have paid twice for ancillary services in Duquesne's proposal. However, Duquesne will now separately unbundle its ancillary services. Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them. Second, the RFP price already includes the value of capacity and installed reserves and no adjustment is necessary.
	5-7	5:10-7:7	Line Losses in T&D	The costs of line losses belong with generation since suppliers will supply energy to make up for line losses, and charge higher prices than wholesale to reflect these costs. In addition, the revenues associated with line losses should not be segregated from those for customer load.	The Company has agreed to remove distribution losses from distribution and increase the CGC credit. Distribution losses will now either be charged to suppliers or competitively supplied.
	7	9-18	Line Losses, Ancillary services and the Company CTC calculation	Since the Company has included line losses and ancillary services in T and/or D, the generation costs are understated.	See changes described above.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	7-8	7:20-8:13	The Two-Part CTC	The Company has not proven lower usage charges will improve efficiency since it has not presented a marginal cost study that demonstrates that the proposed charges are equal to full marginal cost. Proposed design will shift stranded cost responsibilities from customers who increase their usage, relative to a usage-based charge. Also the proposed rate design may be lead to a large number of disputes, especially with new customers.	Duquesne has provided substantial justification and analysis for the proposed rate design in my direct testimony and response to interrogatories. None of the intervenors has provided substantive criticisms of the efficiency gains and potential stranded cost mitigation (of $15 million per year) that I provided in that direct testimony. All customers will benefit from reduced stranded costs regardless of future changes in consumption and the customer-specific CTC prevents cost-shifting. Current and proposed usage rates significantly exceed the marginal costs of generation, distribution, and transmission. The benefits will far exceed any implementation hurdles. Nonetheless, Duquesne agrees to give customers a choice between unbundling of the current rate design and Duquesne's proposed rate design. Customers will be able to choose the best option for them.
	10	6-22	CGC Determination and Adder	It is not clear how the adjustment to reflect average system load shape is done, does not think line losses should be removed, and feels A&G should be added to the wholesale market price.	Adjustments to the RFP price have been made based on hourly retail customer time-of-use data as described in my direct testimony. Duquesne agrees to add avoided distribution and transmission line losses to the CGC. Duquesne rejects the A&G adder. These costs are not avoidable, and if implemented, could create a new category of stranded costs during the transition period.
	11	1-17	Ms. Smith's Calculation of Avoidable Generation Price	Starting with Mr. Doug Smith's projections, Ms. Smith adjusts for line losses and class load shape. A combined DQE and Allegheny system load shape for 1999-2005 was used as a proxy for class load shapes. Line losses were adjusted using generation sales to total sales ratio (5.1%), and adjustment was made for the GRT.	We have agreed to adjust the CGC for avoided line losses using Duquesne figures. The average load shape methodology that Ms. Smith uses is less precise than what the Company used and is not relevant for customers in Duquesne's service area.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	12-13	12:21013:15	Retail Marketing Costs	What Ms. Smith has included is what a competitive supplier would incur and leaving these costs in the CTC would give the Company an unfair advantage.	Duquesne has a monopoly franchise in a regulated environment. Duquesne does not currently incur the marketing costs that Ms. Smith implies and the costs that she identifies are not avoidable.
	14-15	14:7-15:2 15:2-15:19	Ms. Smith's Rate Design	Overall rate design is presented including T&D rates, avoidable generation, and CTC as described earlier. Rates are calculated using Mr. Catlin's adjustments, Mr. Smith's market prices, and Mr. Kahal's stranded costs. Rates provide an 18% reduction.	Ms. Smith's rate design is based on a one-time determination of market prices, which will likely result in uneconomic customer price signals. Further, she fails to recognize the Company's right under Section 2804 (4)(v) to apply excess earnings under the rate cap to mitigate stranded costs for the benefit of ratepayers.
	16	1-2	CTC reconciliation	Reconciliation of the approved CTC should be performed on a class-wide basis to avoid the possibility that certain classes will escape full responsibility.	Duquesne has developed a CTC on an individual customer basis to ensure that all customers pay their fair share of stranded costs.
Alexander (OCA 5)	43-44	43:19-44:3	Load Profiles	It is likely load profiles will be used for some customers, and if they are, they should be updated frequently.	Duquesne will continue to update load profiles and is in the process of installing the CARS system which will greatly aid this effort.
Kalcic (OSBA 1)	3	3-8	Rate Redesign	The Fixed CTC would negatively impact ratepayers and shift responsibility from customers with growing load to those with constant/declining loads. Customers should be able to choose from two tariffs: fixed CTC or variable CTC.	All customers will benefit from more efficient rates and accelerated stranded cost mitigation. The Company's proposal uses customer-specific CTCs and meets the most stringent test of fairness – it prevents cost shifting among individual customers. Mr. Kalcic confuses issues of cost shifting (which the Act prohibits) with revenue shifting (which occurs normally between rate periods under any rate design proposal). However, Duquesne has modified its proposal to give customers a choice between two sets of tariffs as Mr. Kalcic suggests. Customers will be able to choose which rate is better for them.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	9-10	9:9-10:18	Distribution Losses Included in Distribution Rates	The Company is denying customers the opportunity to purchase energy to cover losses. Even if the costs were to be in distribution rates, it should be at market prices, not embedded costs.	Duquesne has modified its proposal and included avoided losses in the CGC.
	10-12	10:19-12:1	Rate Design of CTC and Economic Efficiency	Mr. Kalcic agrees a fixed/variable CTC is preferable to a total variable CTC based on economic theory, but theory would also conclude no CTC is even more efficient.	The Company has proposed to increase efficiency in order to mitigate stranded costs while maintaining other rate principles of fairness and adequacy.
	12-14	12:12-14:4	Rate Design of CTC and Equity	Some customers would be adversely affected by CTC rate design, specifically those with growing loads would do better than those without. Recommends two tariffs option for the CTC (fixed/variable and total variable).	Duquesne has modified its proposal to give customers a choice between two sets of tariffs as Mr. Kalcic suggests. Customers will be able to choose which rate is better for them.
Reising (Enron 2)	2	15-20	Distribution Charges	"The Company inappropriately includes in its distribution charges the cost of losses computed on the basis of its embedded production costs...The production related cost of losses must be removed from unbundled distribution charges."	Duquesne has modified its proposal.
	2	21-24	Distribution Charges	The distribution charge should be split up into a wires charge and a non-wires charge.	This is not consistent with the Commission's proposed rulemaking regarding advanced metering. (See Allison testimony)

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	2-3	2:25-3:3	Ancillary Service Charges	The FERC-regulated ancillary services that the Company has bundled into its proposed transmission charge should be unbundled and stated separately.	Duquesne will separate ancillary services that can be competitively procured from those that Duquesne will be the sole provider. Those that can be competitively procured will be included in generation. A market-based credit will be computed and added to the CGC, which in turn will reduce the CTC by the market value of the generation-based ancillary service. The remaining embedded costs will be recovered in the CTC. Other ancillary services that cannot be competitively procured will be treated just like other wires service (in transmission) and the customer will continue to pay cost-based FERC-approved rates and suppliers will not be obligated to supply them.
	8	5-18	Sales Expenses	"Sales expenses are incurred to promote the sale of additional energy to retail customers." This is not a pure distribution function and shouldn't be included in a distribution charge.	The distribution business will continue to have an interest to build and operate the delivery system efficiently. These and other informational and instructional advertising expenses will still be necessary after retail access. These costs should remain in the distribution function.
	9-10	9:21-10:9	Uncollectable Accounts	Uncollectable accounts expenses should be allocated to production, transmission and distribution based on proportional revenue requirements. The simple allocation of the total expense to distribution is unreasonable.	This argument is flawed because it ignores the fact that under the Competition Act, Duquesne continues to be the supplier of last resort during the transition period while competing suppliers can choose who they serve. This will result in Duquesne continuing to bear the uncollectible expenses.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
Boonin (NEV 2)	3	19-26	Unbundled Price for Generation and CTC	Unbundled price should be set by the market, and should be determined by the market clearing price plus costs for retail delivery. Also unbundled charge and CTC should always be in balance so the total of the two never changes.	Duquesne agrees that a market-based approach to setting the CGC is superior to a one-time administrative estimate. Duquesne has converted the wholesale RFP price to a retail price making adjustments for retail customer time of use consumption, T&D losses, GRT, and will also provide a customer credit for ancillary services. The RFP price includes the value of energy and capacity.
	3-5	3:28-5:1	Unbundling Methodology and the Law	Unbundling is required by 2840(3), and for those customers who do not choose an alternate supplier, the EDU must supply energy at the prevailing market rate as stated in 2807(E)(3).	This passage in the Act refers to the period after the transition period.
	5	3-29	Variable (Market Based) Price for Generation vs. a Fixed Price	A variable price for generation, which can change with market conditions, is more appropriate than estimating and establishing a fixed price.	Duquesne agrees.
	6	5-25	NEV Proposal for Unbundling	Unbundled rate for generation should be set by the power exchange clearing price fully adjusted for ancillary services.	This would be acceptable except a power exchange does not exist in Duquesne's market. That is why Duquesne adopted the RFP process to establish market prices.
	7-8	7:26-8:	Adjustments to Market Price for Reliable, Deliverable Electricity	Costs for capacity, spinning reserve, load balancing (and possibly others) should be included in the price of generation. Price will either be set by ISO and FERC, or through market.	Duquesne has converted the wholesale RFP price to a retail price making adjustments for retail customer time of use consumption, T&D losses, GRT, and will also provide a customer market-based credit for ancillary services that can be competitively procured. There is no ISO in Duquesne's market today. The RFP price includes the value of energy and capacity.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	8	8-20	Other Adjustments to Price for Generation	Price should be adjusted for voltage differences, and for customer location if the ISO establishes different pricing for different regions.	This is not practical and will result in cost shifting. However, if there were an ISO and transmission constraints existed within Duquesne's system, it could make sense to have different pricing for different regions, just as it makes sense to have different pricing in ECAR and PJM.
	8	22-27	Adjusted Power Exchange Price is Good Proxy for Market Price	This is the way goods and services are usually priced (starting with a prevailing wholesale price and adding the costs to convert to retail service).	I agree that a power exchange price could be a good proxy. Depending on how it was designed, it may require different adjustments than what Duquesne sells in the RFP. In any event, this is hypothetical absent a visible power exchange.
	8-9	8:29-9:8	Conversion from Wholesale to Retail Price	The system wholesale energy and capacity price is converted to kWh using a system load factor. Added to this price are: ancillary charges at market prices, A&G and a true-up for tax. A number for each rate class should be then calculated in a similar manner.	Duquesne rejects the A&G adder, and effectively accounts for the other adjustments in its customer credits.
	10	12-16	Load Shape Determination	It is premature to develop load shapes now.	Load shapes are necessary now for the supplier settlement process. Duquesne's CARS project will greatly improve the accuracy of these load shapes in the future.
	10-13	10:18-13:9	Mr. Boonin's Unbundling Proposal and the Rate Cap, Splitting the CTC	Keep the total of the unbundled price of generation and the generation portion of the CTC constant. If market price goes up, the generation portion of the CTC is decreased. The CTC would be split into "generation related" and "non-generation related."	Duquesne does the balancing of the CGC and CTC as Mr. Boonin suggests. However, the Company rejects determining the CTC based on a one-time administrative market price forecast and rejects the proposal to split the CTC into two components. It is not clear what value this extra complication serves and is not intended in the Act.
	13-14	13:11-14:12	Mr. Boonin's Unbundling and Reconciling the ITC and CTC	Reconciliation would be done to each of the two components of the CTC and over/under collections would be deferred to the end of the transition period.	The Company rejects this proposal.

Witness	Page(s)	Line(s)	Issue	Position	Rebuttal
	18	9-19	Final Tariffs	Commission should direct the Company to submit CTC tariffs consistent with Mr. Boonin's approach as shown in Exhibit #2.	See answers above.
	18-19	18:23-19:5	Portability of Tariffs	Any rate discounts should be available to any customer regardless of their chosen supplier to create a level playing field and comply with the Act.	Interruptible customers should not be allowed to receive discounts while obtaining firm electricity service from other suppliers. The discounts are tied to the electricity supply and are therefore discontinued if a customer selects an alternative supplier.

ATTACHMENT IN RESPONSE TO OSBA-02-17

RATE CLASS	CGC BEFORE LOSS OR GRT ADJUSTMENT	T&D LOSS ADJUSTMENT FACTOR*	ADJUSTMENT FOR LOSSES	ADJUSTMENT FOR LOSSES & GRT
RS	17.59	1.105	19.44	20.33
RA	17.51	1.105	19.35	20.24
RH	17.47	1.105	19.30	20.19
GS/GM	17.66	1.096	19.36	20.25
GMH	17.57	1.090	19.15	20.03
GLH	17.60	1.052	18.52	19.37
GL	17.55	1.051	18.45	19.29
L	17.50	1.036	18.13	18.96
HVPS	17.51	1.009	17.67	18.48
SE	17.19	1.105	18.99	19.87
MTS	17.45	1.105	19.28	20.17
AL	17.18	1.077	18.50	19.35
PAL	17.18	1.105	18.98	19.86

* Loss adjustment factors are from Exh. JAL-1d

COST SHIFTING EXAMPLE

			Cumulative (bottom up)	
		Allocator #		Rate GL (kW)
Class Diversified Demand		na, 3		573,790
Portion at Subtransmission		D20, 6		
		D30, 8		46,415
Costs Allocated by Allocator 8 (D30)		Allocated Balance	Percentage of Accounts	Balance In Accounts
Plant Account #'s:				
364&365-Ovhd. Conductor	$	2,759,132	14.18%	
364&365--Accum. depreciation	$	(904,049)		$ (6,375,490)
366&367--Undgd. Lines	$	481,500	0.88%	
366&367-Accum. Dep.	$	(128,169)		$(14,523,015)
368--Transformers	$	532,222	1.73%	
368--Accum. Depreciation	$	(181,688)		$(10,523,089)
Estimated Rate Base	$	2,558,948		
Return @ 15.0% (including tax)	$	383,842		
Depreciation Expense				
acct 364	$	37,040	14.18%	$ 261,212
acct 365	$	26,778	14.18%	$ 188,844
acct 366	$	2,802	0.88%	$ 317,492
acct 367	$	8,045	0.88%	$ 911,574
acct 368	$	12,700	1.73%	$ 735,582
Subtotal Depreciation Expense	$	87,365		
O&M Expenses:				
acct 583	$	25,894	14.18%	$ 182,605
acct 584	$	2,061	0.88%	$ 233,540
acct 593	$	96,293	14.18%	$ 679,072
acct 594	$	2,172	0.88%	$ 246,077
acct 595	$	370	1.73%	$ 21,448
Cost of Service: selected items	$	597,997		
currently divided by GL load of 573,790 kW	$	1.04	per kw yr	
Imputed for load at primary/secondary of 46,415 kW	$	12.88	per kw yr	

COPY

PENNSYLVANIA UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION,	:	
v.	:	Docket No. R-00974104
DUQUESNE LIGHT COMPANY Application for approval of restructuring plan pursuant to 66 Pa. C.S. Section 2806(d).	:	

Washington, D.C.

Monday, November 17, 1997

Deposition of

WHITFIELD RUSSELL

a witness, called for examination by counsel for Duquesne, pursuant to notice and agreement of counsel, beginning at approximately 2:20 p.m., at the offices of Skadden Arps Slate Meagher & Flom, L.L.P., 1440 New York Avenue, Northwest, Washington, D.C., before Shari R. Broussard, notary public in and for the District of Columbia, when were present on behalf of the respective parties:

Q You said may be appropriate for some special treatment. Did you mean to use the word "will" or did you mean to use the word "may be"?

A Well, I -- I think that under the statutory scheme in Pennsylvania, as I understand it, I would recommend that any overstatement of the market price or the CGC turn out to be higher than the market price, that differential should be taken in account in the annual review and in any consideration of an extension of the period of -- transition period. Yes.

Q What do you mean by should be taken into account? The utility should be able to

recover it or no?

A Yes. You know, if they've done all of the other cross -- cleared all the other hurdles.

Q Which are?

A Their obligation to mitigate costs, mitigate stranded costs, increase their efficiency. there's quite a few of them in the statute. We can run through the standards if you would like. I'm not thinking of anything beyond what's in the statute.

during a given calendar year to the Commission?

A I think we will all know where the market price is settling out. Customers talk about what prices they're paying. Customers will be making comparisons. Customers -- there be will be general information. There may even be an indexed published of what people are paying for retail prices.

If that kind of information is not sufficient to indicate where the retail market price has settled out or is trending, then we may have to have some sort of confidential review by an unbiased Commissioner, intermediary to tell us how the CGC and the retail market price, whether they converged or diverged.

Q Is it your, I think you called it a secondary proposal, is it your secondary proposal that the competitive generation credit be set to reflect the anticipated level of cost that retail suppliers would bear? Is that a fair statement?

R-00974104, R-00974104C0001-C0002

DUQUESNE STATEMENT NO. 5 - REJOINDER

Pgh 12/17/97
G. Fenerty

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

APPLICATION OF DUQUESNE LIGHT COMPANY

FOR APPROVAL OF ITS RESTRUCTURING PLAN

UNDER SECTION 2806 OF THE PUBLIC UTILITY CODE

REJOINDER TESTIMONY

OF

JAMES A. LAHTINEN

RESPONDING TO INTERVENOR SURREBUTTAL TESTIMONY ON DUQUESNE'S MARKET-BASED RFP AND CGC DETERMINATION AND DUQUESNE'S PROPOSAL TO REDESIGN ITS TARIFFS TO MITIGATE STRANDED COSTS

JAMES A. LAHTINEN REJOINDER TESTIMONY

Q. Please state your name.

A. My name is James A. Lahtinen.

Q. Are you the same James A. Lahtinen who filed direct testimony in this docket on August 1, 1997 and rebuttal testimony on December 2, 1997?

A. Yes, I am.

Q. What is the purpose of your rejoinder testimony?

A. To respond to criticisms of Duquesne's proposal to use the results from an annual RFP process to establish market power prices and customer generation credits (CGCs) and Duquesne's proposal to unbundle and redesign its tariffs towards more efficient levels to mitigate stranded costs. Based on the intervenor surrebuttal testimony, there still appears to be considerable confusion or mischaracterization of Duquesne's proposal.

Q. Please turn to the first issue you are addressing.

A. MAPSA witness Mr. Russell seems to imply that Duquesne fails to consider suppliers' costs of serving retail customers when establishing the CGC. As a result, he contends the CGC is set artificially low and will discourage supplier participation in competitive markets. (Russell surrebuttal, p.3, lines 40-41) This characterization is incorrect. First, Duquesne's annual RFP (as currently designed) reflects the value of energy, capacity and the reserves necessary to stand behind the firm obligation to supply

power. Second, Duquesne adjusts the RFP price to reflect the retail customer class time of use consumption on an hourly basis when determining the CGC. Third, as stated in my rebuttal testimony, the RFP price will be adjusted upwards for transmission and distribution losses, as well as gross receipts tax. Fourth, Duquesne will also provide a credit for ancillary services that the suppliers can either purchase directly from Duquesne or choose to supply themselves. Finally, Duquesne has committed to sell electricity to suppliers in future RFPs, thereby allowing the winning bidders to sell power to retail customers in its service territory. By definition, the RFP provides suppliers with an opportunity to obtain power in the wholesale market and turn around and sell it to a retail customer at price levels consistent with the CGC. Furthermore, as market conditions change over the transition period, annual CGCs will reflect these changes and send customers the proper price signals.

Q. How do you respond to claims that the terms of the RFP were restrictive and somehow reduced the value of the electricity sold in the RFP?

A. There are several points I would like to make here. First, both Mr. Russell and Mr. Weisenmiller grossly mischaracterize the product being sold in the RFP. The 50% must take provision in the RFP was not included to depress bid prices but rather was to intended to recognize the realities of Duquesne's generation mix which is mostly base-load. Moreover, I would note that must-take provisions are not uncommon in power contracts where the seller takes on an obligation to supply capacity on demand; one example is the capacity sales to Duquesne by marketers that are referenced in Mr. Irvin's direct testimony and my rebuttal testimony. Second, both Mr. Russell and Mr. Weisenmiller present unwarranted criticisms regarding related transmission services.

For example, contrary to Mr. Russell's contention (page 8, line 10), Duquesne has never posted 0 firm ATC's. Duquese began posting firm ATC's on May 5, 1997 -one month before the RFP was sent out and since that time Duquesne has posted firm ATC's of 250 MW over the Elrama-Mitchell tie, and 500 MW over the OE, AEP, Toledo, and Centerior ties. In addition, Mr. Russell's (page 8, lines 20-27) and Mr. Weisinmiller's (page 45, line 4-13) contention that the RFP purchasers bear the risk of transmission interruptions is not credible. The RFP contract does not permit Duquesne to interrupt deliveries if there are transmission limitations on the Duquesne system. See RFP Contract Section VI. I also find mystifying Mr. Weisinmiller's suggestion that, if such constraints occur, Duquesne should be required to incur the cost of purchasing transmission to re-deliver the power at (he seems to assume) any point in the United States selected by the purchaser (page 43, line 21). That is hardly a reasonable suggestion, much less one that has anything to do with establishing market prices in Duquesne's area. Third, Mr. Russell incorrectly asserts (pages 10-11) that recent capacity purchases by Duquesne do not support the values cited in my rebuttal testimony or revealed in the RFP. Exhibit JAL-15 clearly shows that the capacity values reflected in the two purchases Duquesne made in 1996 and 1997, respectively are $1.50/MWh and $.90/MWh. Furthermore, they are the same contracts Mr. Russell relies on to "question" my earlier calculation. The data shows that when the energy prices in those contracts as are measured against the ECAR peak and off-peak prices during the relevant time periods, it is clear that those energy prices did not contain any "hidden" capacity charges. (I also note that Mr. Russell is incorrect that

Duquesne failed to supply the contracts themselves (page 10, line 6); Duquesne has supplied all power contracts requested under the protective order.)

Q. *Please support your earlier statement that there is some confusion over Duquesne's treatment of ancillary services and line losses.*

A. Yes, there are several points I would like to make.

- OCA witness Lee Smith criticizes Duquesne for not allowing more ancillary services to be "competitively supplied." (Lee Smith, surrebuttal at pp.1-2) I would like to make clear that Duquesne is not responsible for determining which services can and cannot be supplied competitively, as the OCA implies. Duquesne will abide by Order No. 888, which requires transmission providers to permit their customers to self-provide ancillary services to the extent it is technically feasible under applicable regional reliability council standards. If these rules change over time, Duquesne will modify its proposal accordingly.
- Ms. Smith incorrectly asserts in her surrebuttal that supplemental reserve costs will be allocated to transmission. She states that "supplemental reserve costs included in transmission are based on embedded costs" and recommends that these costs be transferred from transmission to generation. (Lee Smith, surrebuttal at p. 3, lines 5-12) My rebuttal testimony clearly states that "ancillary services that can be competitively procured, such as supplemental reserves, will be included in generation." (Lahtinen, rebuttal at p. 20, lines 4-5). Furthermore, my direct testimony indicates that supplemental operating reserves are included in generation. (Lahtinen, direct at p. 55) Ms. Smith's characterization of our proposal therefore is not correct.

- Ms. Smith also incorrectly asserts in her surrebuttal that "the Company still plans to charge for transmission losses through its transmission rate (although alternative suppliers may provide for their own losses)." (Lee Smith, surrebuttal at p. 3, lines 20-22). Both my direct and rebuttal testimony clearly indicate that transmission energy losses are included in the generation CGC component, and not transmission rates, as Ms. Smith asserts. (Lahtinen, direct at pp. 10, 60-61, Exhibit JAL-11; Lahtinen, rebuttal at pp. 3, 20).

Q. Are other witnesses still contending that Duquesne's proposed rate design will result in cost-shifting?

A. Mr. Russell seems now to be alone on the "cost shifting" issue. He asserts (page 6, line 26 - page 7, line 8) that Duquesne's rate design violates the Act's prohibition against intra-class cost shifting. I find his continued criticism baffling since that his client, ENRON (a member of MAPSA), has supported the same CTC rate design philosophy in the New York State restructuring proceedings (Cases: 96-E-0891,96-E-0897, 96-E-0898, 96-E-0900, and 96-E-0909). Dr. Miles Bidwell, who filed testimony on behalf of ENRON and IPPNY in that case recommended a rate design proposal to recover a large portion of the CTC in a fixed customer charge and the remaining portion in a variable (kWh) charge, concluding, as I do here, that such a rate design is not only more efficient (because it more closely reflects marginal costs) but provides significant stranded cost mitigation opportunities as well as customer benefits.

Q. Is there anything else you would like to add regarding rate re-design?

A... Yes. In my rebuttal testimony, I indicated that in part, based on the recommendation of OSBA witness Kalcic, the Company would now propose to make its rate re-design available on an optional basis. While this is acceptable to Mr. Kalcic and Mr. Baron, it is still unacceptable to Mr. Russell and Ms. Smith of the OCA. I recommend that the Commission reject their arguments (as they are intellectually defensible) and allow the Company to offer its innovative rate design on an optional basis to the betterment of electricity consumers, competing suppliers and the Company.

Q. Does this complete your testimony?

A. Yes.

R-00974104, R-00974104C0001-C0002

VOLUME III

Duquesne Statement No. 7

Pgll 12/17/97
G. Garrity

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

DUQUESNE LIGHT COMPANY
DOCKET NO. R-00974104

Direct Testimony
of
Robert A. Irvin

Contents:

Regarding Current Prices of Electricity, Certain Retail Access Implementation Issues, and the Separation of Transmission and Distribution Assets

Duquesne Statement No. 7

DIRECT TESTIMONY OF ROBERT A. IRVIN

I. QUALIFICATIONS

Q. Please state your name, address and job title.

A. My name is Robert A. Irvin and my business address is 411 Seventh Avenue, Pittsburgh, Pennsylvania 15230-1930. I am employed by Duquesne Light Company ("Duquesne") as General Manager, System Operations Unit.

Q. Please describe your work history at Duquesne.

A. I have been employed in this position since August 1988. I have held various positions in System Operations since I joined the Company in June 1960, except for the period from 1978 to 1984 when I was Technical Assistant to the Vice President of Operations. I have worked for Duquesne for 37 years.

Q. Please describe your current responsibilities at Duquesne.

A. Among my duties as General Manager, System Operations Unit, I am responsible for bulk power sales and purchases. In performing my duties, members of my organization negotiate power transactions on a day-to-day basis with representatives of other vertically integrated utilities in Duquesne's market, as well as power marketers that typically do not own generation assets.

II. SUMMARY OF TESTIMONY

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is threefold. First, I will discuss several market issues

related to Duquesne's filing – current market prices for power delivered in Duquesne's service territory and the Request for Proposals ("RFP") recently issued by Duquesne. Second, I will discuss certain implementation issues of retail choice concerning open access to unbundled distribution, transmission, and ancillary services, as well as how Duquesne proposes to implement legislative requirements for distribution companies and electric suppliers. Finally, I will describe how Duquesne differentiated between PaPUC-jurisdictional distribution and FERC-jurisdictional transmission assets.

Q. Please summarize your conclusions regarding market issues.

A. First, I conclude that the average hourly market price of power sold by Duquesne has been and currently remains below $0.02/kWh (or $20 per MWH). My conclusion is based on actual sales made by Duquesne over the past several years. I also present the results of Duquesne's recent competitive market solicitation to sell at wholesale (i) 50 MW of firm power for the term of one year, commencing January 1, 1998 and (ii) 100 MW of firm power for a term of eight years, commencing January 1, 1998. The winning bids reveal levelized market prices of $18.16 and $20.19 per MWH for one and eight years, respectively.

Q. Please summarize your conclusions with respect to the implementation of retail choice.

A. I have three main conclusions. First, Duquesne's plan provides non-discriminatory, open access for distribution, transmission and ancillary services. Second, Duquesne's plan complies with the requirements in Sections 2807 and 2809 of the Electricity Generation Customer Choice and Competition Act (hereafter referred to as the "Act") pertaining to the responsibilities of distribution companies and requirements of electric suppliers,

respectively. Third, Duquesne's plan will maintain system reliability both as it pertains to transmission service and generation reserves.

Q. Please summarize your conclusions regarding how Duquesne split distribution and transmission assets for purposes of differentiating between PaPUC-jurisdictional distribution and FERC-jurisdictional transmission.

A. Duquesne's engineering analysis supports continued use of the transmission/distribution functionalization that is reflected in Duquesne's system of accounts. Maintaining this traditional functionalization will prevent cost-shifting and therefore is consistent with the intent of the Act.

III. MARKET ISSUES

Q. Please describe the market issues you plan to discuss.

A. I will discuss two market issues related to Duquesne's filing:

1. Current market prices in this market
2. The recent competitive RFP Duquesne issued to sell firm power and the results from that solicitation.

Each of these is addressed in turn.

1. Current Market Prices in the Duquesne Market

Q. Please discuss your experience with respect to the market price of power for Duquesne-supplied generation.

A. I will first discuss Duquesne's annual sales to a customer within PJM that have ranged between 100 MW and 350 MW over the past four years (1994-97). I do not refer to the

PJM customer by name because it has requested that its identity be kept confidential. However, I am attaching the relevant price information as Exhibit RAI-1 to my testimony.

Q. What prices were contained in the agreements?

A. In accordance with the customer's preferences, the prices were structured to include a demand charge, an operating capacity charge and an energy charge. (There also were scheduling provisions and penalties for non-delivery that increase the "firmness" of the power from a financial perspective.) Combining these various charges, I provide below a calculation of the annual average price (in $/MWH) using (i) the assumption that the customer would schedule the full contract amount each hour and (ii) the actual delivered amounts (computed on an "after the fact" basis). While the former may better reflect the market price to the customer at the time it agreed to these prices, I include the latter for completeness.

Year	Prices at Anticipated Deliveries	Prices at Actual Deliveries
1994	$18.37/MWH	$18.49/MWH
1995	$19.07/MWH	$19.28/MWH
1996	$18.90/MWH	$18.93/MWH
1997	$17.52/MWH	$17.48/MWH (Jan. – June)

The support for my calculations is included in Exhibit RAI-2.

Q. How was the power delivered to PJM?

A. Duquesne delivered the power to its interconnection with West Penn Power Company;

West Penn transmitted the power across its system to PJM; and the customer, a member of PJM, used its contractual rights to use certain PJM transmission facilities to import the power to its system. The cost of transmitting power from Duquesne to the customer was borne by the customer, not Duquesne[1]. Thus, the contract prices were for delivery at the Duquesne-West Penn border and reflect the market price in the Duquesne area, not market prices in PJM, which tend to be higher than those in ECAR. Mr. Lahtinen discusses the price differences between PJM and ECAR in more detail.

Q. Do any other recent power transactions provide relevant information?

A. Yes. In 1996 and 1997 Duquesne entered into contracts giving Duquesne the option to purchase firm power during the peak summer months. Duquesne entered into these contracts as a form of insurance against unexpected generation outages or summer load exceeding projected levels. The contracts included two different charges. The first was a reservation charge for the right to call on a specified amount of generating capacity. The second was an energy charge that would apply if and when Duquesne exercised its option to schedule the capacity.

Q. Can you calculate a value of firm capacity from the reservation charge?

A. Yes. I calculate this capacity value by dividing the reservation fee (which gives Duquesne the right to call on the capacity) by the number of on-peak hours that the fee entitles Duquesne to schedule capacity under the contract. (See Exhibit RAI-3.) The resulting charge is $0.0009/kW-hr ($0.9/MW-hr) for 1996 and $0.0015/kW-hr

[1] The only exception was that, for the 1997 sale, Duquesne agreed to supply the losses across the West Penn System associated with the sale. These losses represent only 3% of the total sale.

($1.5/MW-hr) for 1997. As these figures indicate, even for the peak summer months, the market price of firm capacity is very low.

2. Description of RFP and the Results

Q. Please describe the RFP recently conducted by Duquesne.

A. On June 6, 1997 Duquesne issued an RFP seeking bids (i) to purchase 50 MW of firm power for a term of one year, commencing January 1, 1998, and (ii) to purchase not less than 100 MW, nor more than 500 MW, of firm power for a term of eight years, commencing January 1, 1998. The specific terms of the RFP, and the associated Power Sales Agreement, are set forth in Exhibit RAI-4.

Q. Please describe how potential purchasers were made aware of the RFP.

A. Duquesne made extensive efforts to publicize the RFP and encourage broad purchaser participation. The RFP was sent directly to approximately 300 potential purchasers. The list of potential purchasers included all power marketers registered with FERC as well as various utilities with which Duquesne sells and purchases power from time to time. (See Exhibit RAI-5 for a list of the suppliers who received the RFP.) In addition, a press release was distributed to a large number of news and industry trade publications (Exhibit RAI-6) and an advertisement was published on page A2 of the Wall Street Journal on June 9, 1997 (Exhibit RAI-7.) The RFP and associated documents also were made available in their entirety on-line over the Internet. Several industry publications printed stories about the RFP. Exhibit RAI-8 provides a sample of the articles published.

Q. You stated that Duquesne made extensive efforts to publicize the RFP. Did Duquesne

design any aspects of the RFP to further encourage responses to the RFP?

A. Yes, the RFP had several features that were intended to encourage participation. For example, bidders were permitted to submit bids as small as 2 MW. Typically, wholesale transactions involve much larger quantities, but Duquesne chose to also allow small suppliers an opportunity to purchase firm power in the RFP.

Duquesne also made a commitment to sell power to the highest bidder(s). Duquesne included this commitment because, in my experience, it is not uncommon for a utility to conduct an RFP without following through by awarding capacity and energy to the winning bidders. Uncertainty regarding the utility's level of commitment to an RFP can dampen bidder participation, something Duquesne sought to avoid through this commitment to sell.

Duquesne also made the RFP as detailed as possible. Duquesne published an explanatory document (the RFP itself) that provided all the relevant bidding rules, summarized important contractual terms, and provided a formal schedule pursuant to which bids would be submitted and considered. Duquesne also included a standard form contract (the Power Sales Agreement, or "PSA") that each winning bidder would sign. The PSA provided bidders all the relevant contractual information in advance and reduced the uncertainty associated with negotiations over non-price terms and conditions.

Finally, Duquesne invited bidders to submit questions and comments on the RFP. Duquesne committed to respond promptly to each inquiry by posting each question and answer on Duquesne's Internet page. This process allowed potential bidders to resolve questions in advance of submitting their bids. It also ensured that all bidders would have

access to the same information on which to base their bids, given that all answers were posted on the Internet. This process attracted 15 questions, each of which Duquesne answered promptly. In one instance Duquesne agreed to modify the PSA to accommodate a potential bidder's concern. See Exhibit RAI-9 for RFP questions and answers.

Q. Please turn to the substantive terms of the RFP. You stated that Duquesne offered to sell "firm power." What does "firm power" mean in the context of a competitive generation sector?

A. To answer the question I first must describe the meaning of "firm power" prior to the recent era of open access. Traditionally, firm power connoted a commitment to provide the customer with a level of reliability comparable to that provided to franchised retail customers. This meant, for example, that a firm sale would be curtailed only after all economy energy sales had been curtailed and after the curtailment of interruptible retail customers. To the extent, however, that the firm sale had to be interrupted, there was no associated financial penalty. Thus "firmness" of the sale was related to the customer's place in a curtailment priority queue and, in many instances, was accompanied by a "best efforts" commitment to secure power on the wholesale market should the utility's internal resources be insufficient to meet the demands of all firm customers.

In today's market environment, however, curtailment priorities that relate to "native load" commitments and "non firm" sales have less relevance, and power marketers in particular are demanding that "firm power" be backed up by financial penalties for a failure to deliver. Duquesne therefore structured its PSA to provide both a

contractual obligation to sell power on a firm basis and financial penalties should Duquesne fail to deliver. Specifically, Duquesne is obligated to make available the full contract amount to the purchaser during every hour of the contract term, subject only to a minimum hourly schedule of 50% of the contract amount and an annual 75% capacity factor. If, for any reason, Duquesne cannot deliver the power scheduled by the purchaser -- either through dispatch of its own generation or by Duquesne purchasing power from third parties -- the purchaser has the right to secure replacement power, and Duquesne will reimburse the purchaser for the increased costs associated therewith. The customer therefore is held harmless, from a financial perspective, for a failure to deliver. Duquesne also added a provision to address the unlikely circumstance where neither Duquesne nor the purchaser is able to secure power, an instance most likely limited to widespread curtailments of customer load throughout the region. In such an unlikely circumstance, the purchaser would receive a credit of $200 for each MWH scheduled but not delivered.

Q. Please turn to the bids Duquesne received in response to the RFP.

A. Duquesne received five bids on the one-year sale for a total of 210 MW and 11 bids on the eight-year sale for a total of 1,300 MW.

Q. How were the bids evaluated?

A. Duquesne awarded firm power to the highest bidders on a dollar per MWH basis, not a total revenue basis. For example, a 10 MW bid at $20 per MWH was ranked higher than a 40 MW bid at $19 per MWH. The eight-year bids were ranked on a present value basis using a 7.94 percent discount rate.

Q. How many purchasers were awarded contracts?

A. The 50 MW of one-year power was divided between two bidders. One bidder was awarded the entire 100 MW for the eight-year sale.

Q. Can you release the names of the winning bidders?

A. I can do so for the one-year sale. The winning bidders were CMS Marketing and Trading and American Municipal Power-Ohio. However, the winning bidder for the eight-year sale submitted its bid on the condition that it be kept confidential.

Q. Can Duquesne release the bid prices it received?

A. To encourage participation, Duquesne committed to maintain the confidentiality of the bids. However, I can provide the Commission relevant information regarding the bid prices without revealing the specific prices contained in specific bids. I will do so by providing (i) the range of bid prices submitted for the one-year sale and the weighted average of the winning bids for that sale, and (ii) the range of bid prices for the eight-year sale and the nominal levelized price associated with the winning bid for that sale. A "levelized" price calculation yields a constant price each year of the contract term that provides the same revenue, on a present value basis, as the actual price stream submitted by the winning bidder for the eight-year sale. Duquesne therefore can provide market price information without disclosing the bids themselves.

Q. Please describe this price information.

A. For the one-year firm power, the lowest bid was $15.3/MWH and no bid was higher than $19/MWH. The weighted average of the two winning bids was $18.16/MWH. As to the eight-year sale of power, the lowest bid was $16.5/MWH on a levelized basis and the

winning bid was $20.19/MWH on a levelized basis.[2] These are "nominal" levelized figures that apply throughout the eight years in contrast to a "real" levelized number that escalates each year with an inflation factor. The real levelized prices associated with the winning bid for the eight-year sale are provided in Mr. Schnitzer's testimony.

Q. Did the winning bid prices include the cost of transmission losses and other delivery charges?

A. No. Under the RFP, purchasers were required to secure transmission service over the Duquesne transmission system. Therefore, the bid prices that Duquesne solicited relate solely to the value of Duquesne's firm power at the generating station, not the cost of delivering that power (e.g., transmission charges).

IV. IMPLEMENTATION OF RETAIL CHOICE

Q. What retail choice implementation issues do you discuss?

A. I discuss two major issues. First, I describe Duquesne's open access proposal related to distribution, transmission, and ancillary services, and second, I explain how Duquesne's plan complies with Section 2807 and Section 2809 of the Act pertaining to responsibilities of distribution companies and requirements for electric suppliers.

Q. Describe Duquesne's open access proposal with respect to the treatment of nondiscriminatory distribution service?

A. Customers choosing alternative suppliers will be subject to distribution and customer

[2] These nominal levelized prices are based on a 7.83% discount factor since the Company's after-tax weighted average cost of capital was revised after the RFP was issued. This discount factor is the same as the after-tax weighted cost of capital included in Mr. Clayton's testimony.

charges that reflect the cost of "local distribution" facilities and other retail services subject to the jurisdiction of the Commission. This service will be available and provided on a nondiscriminatory basis to customers electing retail choice and to Duquesne's bundled service customers.

Q. Describe Duquesne's open access proposal with respect to the treatment of transmission and ancillary services?

A. FERC Order 888 requires that public utilities offer open access, nondiscriminatory transmission access pursuant to filed tariffs. On July 9, 1996, Duquesne filed a tariff identical to the Commission's pro forma tariff, offering point-to-point and network transmission service. This tariff includes embedded cost rates for transmission and ancillary services. (Some of these rates are "up to" charges.) The FERC accepted the non-rate terms and conditions of the tariff,[3] and the rates have been effective, subject to refund, since July 9, 1996.

Order 888 held that the FERC has jurisdiction over the rates, terms and conditions of unbundled transmission service to retail customers (but not over the rates, terms and conditions of local distribution service). Consistent therewith, Duquesne will provide retail transmission access pursuant to the terms and conditions of FERC's pro forma tariff and unbundled rates that recover Duquesne's embedded cost revenue requirement.

Q. Which ancillary services will be offered?

A. Duquesne will offer all the ancillary services required to be offered by FERC under Order 888. The services are scheduling; reactive power; regulation and frequency control;

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[3] Atlantic City Electric et al., 77 FERC ¶ 61, 144 (1996).

spinning reserve; supplemental reserve; and energy imbalance.[4] Mr. Lahtinen discusses the rates for these services.

Q. Can electricity suppliers offer these services as well?

A. The FERC's Order No. 888 answers this question. I will summarize FERC's findings regarding each service below. For convenience, I discuss the services in three groups.

Scheduling; Reactive Power. Order No. 888 held that scheduling service and reactive power must be purchased from the transmission provider. Duquesne will comply with this requirement by offering these services at cost-based rates to its customers.

Energy Imbalance; Regulation and Frequency Control. Order No. 888 recognizes that energy imbalance service and regulation and frequency response service are services that are automatically provided by the control area operator because only the control area operator can balance the difference between the amount of power scheduled and the amount of power consumed on a dynamic basis. The two services are similar but distinct. Energy imbalance service is associated with mismatches in generation and load over an entire hour, while regulation and frequency response service is associated with balancing generation and load on a moment-to-moment basis within each hour. Because Duquesne's generation automatically responds to restore the balance between the power scheduled and the power consumed, Duquesne automatically provides this service to each of the customers within its control area.

The FERC recognized, however, that some customers may desire to use "dynamic

[4] The FERC does not consider transmission losses to be an ancillary service and therefore losses are discussed separately below.

scheduling" to avoid energy imbalance charges and regulation and frequency response charges. Dynamic scheduling essentially removes the customer's load from Duquesne's control area and places that customer's load within another control area. As a result, Duquesne's generation is not required to respond to restore supply and demand imbalances for that customer; rather, generation in the other control area provides the required response. Order No. 888 requires Duquesne to work in good faith with suppliers that wish to establish dynamic scheduling and requires the customer to pay the associated costs. Duquesne will comply with these requirements.

Operating Reserves (Spinning and Supplemental). The other two services are different types of operating reserves: (i) spinning reserve service and (ii) supplemental reserve service. As described by FERC: "Operating reserve is extra generation available to serve load in case there is an unplanned event such as loss of generation. Generation held for operating reserve should be located near the load, typically in the same control area." Order No. 888 at 214. Duquesne will offer these services to customers at cost-based rates, as required by Order No. 888, and will allow electric suppliers to offer these services to the extent they are permitted to do so under ECAR rules. At present, ECAR requires that spinning reserve be provided within the control area, but does not impose the same requirement on supplemental reserve. Duquesne will comply with this ECAR rule and will provide spinning reserve service to all customers within the control area and will allow electric suppliers to offer supplemental reserves.

Q. Who will pay for these services?

A. Three of the services will be charged directly to all retail customers within Duquesne's

control area: reactive supply, regulation and frequency control, and spinning reserve. Having paid the rates for these services, as well as for transmission and distribution service, customers electing retail choice will have the ability to receive power from any electric supplier without the imposition of additional charges from Duquesne for these services.

Electricity suppliers will be responsible for the other three services (scheduling, energy imbalance and supplemental reserve). This is appropriate because these charges are dependent on actions undertaken by the suppliers. For example, scheduling charges will vary with the number of schedules and schedule changes submitted. Energy imbalance charges will vary with the degree to which a supplier's schedule matches the demands of its customers. Duquesne will charge for supplemental reserve only if the supplier chooses to purchase supplemental reserve from Duquesne. As Mr. Lahtinen describes, control area customers will receive an annual credit for revenues collected from suppliers, net of any additional expenses incurred. This will ensure that customers are not "charged twice" for ancillary services.

Q. How will Duquesne treat transmission losses?

A. Duquesne will require electricity suppliers to supply or purchase the transmission losses associated with their electricity deliveries over the Duquesne transmission system. (Distribution losses will be recovered as part of the distribution charge.) Electricity suppliers will have the option of providing the real power losses themselves or purchasing them from Duquesne consistent with FERC Order 888. The rate (if purchased from Duquesne) and the amount of losses that must be supplied will be governed by

Duquesne's FERC's pro forma tariff.

Q. Explain how Duquesne will satisfy Section 2807 of the Act relating to responsibilities of distribution companies?

A. The Act requires distribution companies to:

> maintain the integrity of the distribution system at least in conformity with the National Electric Safety Code and such other standards practiced by the industry in a manner sufficient to provide safe and reliable service to all customers connected to the system consistent with the Act and the Commission's regulations. In performing such duties, the electric distribution company shall implement procedures to require all electric generation suppliers to deliver energy to the electric distribution company at locations and in amounts that are adequate to meet the energy supplier's obligations to its customers. [Section 2807 (A)]

Duquesne will continue to provide safe and reliable delivery service (i.e., transmission and distribution) to all customers. As to safety, Duquesne will continue to operate its facilities to ensure public and worker safety to the maximum practicable extent. As to reliability, the delivery portion of the service will be firm and thus will be no different in quality than the service customers receive today. To comply with the Act, Duquesne's distribution business will abide by the following procedures for review by the Commission:

- The distribution business will have the ability to receive energy at all points on its system sufficient to meet the needs of all electric generation suppliers' customers on its system.
- The distribution business will not have an obligation to install nonstandard facilities unless the energy supplier or its customers pays the full cost of these facilities.

- The distribution business shall upgrade its system to meet changing customer requirements consistent with the requirements of Section 1501 relating to character of service and facilities.

Duquesne will also ensure accurate, concise and timely information exchange between the local distribution business, competitive electric generation suppliers and the control area operator.

Mr. Allison describes in his testimony how Duquesne's plan complies with specific requirements in the Act pertaining to customer billing, consumer protections and customer service, Section 2807 (C) and (D). The Act also requires that, prior to the implementation of retail access in 1999, "each electric distribution company, in conjunction with the Commission, shall implement a consumer education program" that "provide[s] consumers with information necessary to help them make appropriate choices as to their electric service." Section 2807(D)(3). Mr. Hoffmann will address how Duquesne's distribution business shall implement a consumer education program that complies with this section of the Act.

Q. The Act requires that the distribution company retain its full obligation to serve, including the connection of customers, the delivery of electric energy and the production or acquisition of electric energy for customers, during the period when it is collecting a CTC. Section 2807 (E). Please describe how the distribution company will comply with this obligation to serve?

A. Duquesne's distribution business will maintain throughout the transition period its "full" obligation to serve consistent with the Act:

- For customers that either do not yet have retail access or choose to continue taking supply services from Duquesne, the Company will continue to plan and operate its system to serve their demands in the same manner as it does today.
- For customers that choose an alternative electricity supplier, Duquesne will have an obligation to provide firm transmission, distribution and ancillary services, as well as allow customers to return to Duquesne's unbundled generation service at the rate cap.

In addition, as the Act requires, Duquesne will maintain adequate reserve margins in conformity with the standards required by NERC and ECAR. Section 2804 (1). I discuss the operating reserve requirements later in my testimony and Mr. Karl describes how Duquesne will maintain adequate reserve margins throughout the transition period.

Q. Explain how Duquesne will satisfy Section 2809 of the Act pertaining to requirements for electric suppliers?

A. As part of Duquesne's effort to provide customers the same level of system reliability that they currently enjoy today, certain requirements related to electricity supplier ("Supplier") involvement are included as an integral part of Duquesne's Customer Choice Plan. Suppliers must provide satisfactory documentary evidence of certification or licensure by the Commission.

Q. Does Duquesne propose that the Commission's already promulgated interim licensing requirements be adopted for general use during the phase-in and beyond?

A. Yes. Duquesne plans on adopting the Commission's licensing requirements.

Q. What procedure will Duquesne employ to ensure that all Suppliers for whose customers

Duquesne is providing unbundled electric delivery service have current licenses?

A. In addition to the requirement that suppliers in Duquesne's retail access program provide documentary evidence of licensure, Duquesne proposes that the Commission inform Duquesne immediately when a Supplier's license has been revoked. In such circumstances, during the period in which Duquesne will be recovering its CTC, and in accordance with its obligation to serve, Duquesne will provide power to customers until or unless the customers obtain their supply from another Supplier.

Q. What is the reciprocity requirement in the Act and how will Duquesne comply with that requirement?

A. The Act provides that "no electric utility regulated by the Commission and no affiliate of such electric utility may use the distribution system of another electric utility regulated by the Commission or make sales to end-use customers in another electric utility's service territory unless the Commission has approved a restructuring plan for the supplying electric utility which provides for direct access comparable to the direct access provided under the approved plan of the electric utility operating the distribution system in the location where the supplying electric utility seeks to sell electricity to an end-use customer." See Section 2805. Duquesne will implement procedures that ensure compliance with this provision of the Act. For example, an affiliate or competitive generation marketing group or division of a Pennsylvania jurisdictional utility will be able to sell generation to customers in Duquesne's service territory only if any Duquesne competitive marketing group or generation affiliate has comparable access to customers of that Pennsylvania jurisdictional utility, and that utility applies the provisions of its

FERC transmission tariff in making sales to Duquesne's customers.

Q. Will suppliers be required to sign/enter into any agreement with Duquesne?

A. Yes. Duquesne and suppliers will enter into standard form service agreement governing, among other things, certain ancillary service charges.

Q. What technical and operation standards will Duquesne require Suppliers to meet?

A. In order to serve retail load in Duquesne's control area, all suppliers will be required to "deliver" electricity to Duquesne's control area in amounts sufficient to supply customer load and transmission losses. Suppliers can comply with this standard by purchasing electricity in Duquesne's annual competitive RFP solicitation or by supplying electricity from an entity other than Duquesne. In addition, all Suppliers will be responsible for procuring or providing certain related ancillary services. These and other requirements will be applied in a nondiscriminatory manner to all electricity suppliers, and are designed to maintain existing consumer protections.

Q. Explain how Duquesne will maintain system reliability with respect to generation operating "reserves"?

A. All Suppliers will be subject to the same operating reserve requirements as Duquesne. Under ECAR rules, supplemental reserve may be provided from sources outside the control area or purchase the reserve from Duquesne. Suppliers shall provide or arrange to be provided, as a minimum, Daily Supplemental Operating Reserve equal to the amounts as set forth in ECAR Document No. 2, as follows:

> **Supplemental Reserve** — An amount equal to 3% of that Supplier's maximum 60-minute integrated clock hour Internal Load less Qualified Interruptible Load

projected for the day. Supplemental Reserve must be capable of being maintained for at least four hours. This portion of the Daily Operating Reserve is to provide for protection against an unexpected loss of generating capacity and load forecast error and may be allocated among the acceptable components in any combination within the following prescribed limits.

a. 0-100% Spinning Reserve which may be fully utilized within ten minutes
b. 0-100% Non-Spinning Reserve that may be fully utilized within ten minutes which may include: Qualified Interruptible Load or Qualified Quick-Start Generating Capacity
c. 0-100% prescheduled assistance from another System(s) which is fully applicable within 10 minutes.

Q. How does Duquesne propose to handle the Supplier settlement process and determine energy imbalances?

A. This matter is addressed by Mr. Allison.

V. DESCRIPTION OF SPLIT BETWEEN TRANSMISSION AND DISTRIBUTION ASSETS

Q. How did Duquesne split transmission and distribution assets for purposes of differentiating between PaPUC-jurisdictional distribution and FERC-jurisdictional transmission?

A. Duquesne maintained the split in accordance with the way the assets are presently booked in Duquesne's system of accounts.

Q. Please provide a brief description of Duquesne's electric distribution system.

A. The distribution system consists of a network of overhead and underground 23 KV subtransmission, 13.2/23 KV distribution and 4 KV distribution circuits supplied from

strategically located distribution supply substations which are connected to the bulk Transmission System. The 23 KV subtransmission lines originate at these distribution substations and form a complex network that interconnects the distribution substations. These subtransmission lines are used to support the loss of capacity of one of the distribution substations, to provide service to the larger retail customers, and to supply the 13.2/23 KV distribution and 4 KV distribution substations described below. Both the 13.2/23 KV distribution and 4 KV distribution circuits are radial circuits with normally open ties, and are used to supply smaller customers and most customers whose electric requirements fall in the intermediate range. The 13.2/23 KV distribution circuits originate in most cases from the same distribution substations that supply subtransmission lines. The 4 KV distribution circuits are supplied from and originate at numerous 4 KV distribution substations and some 13.2/23 KV distribution connected to the 23 KV subtransmission system.

Q. Please describe briefly the Company's transmission system.

A. Duquesne's transmission system consists of approximately 161 miles of 345 KV lines, 410 miles of 138KV lines, 145 miles of 69 KV lines, the interconnections with neighboring utilities and the 37 bulk power substations where the transmission lines terminate. Duquesne's wholly-owned generating units and the jointly-owned CAPCO generating units operated by Duquesne are connected to Duquesne's transmission system. Other CAPCO generating units in which Duquesne has an ownership interest are connected to CAPCO transmission lines located on the system of the operator of each of these units. Duquesne has an investment responsibility in these CAPCO transmission

lines.

Q. Does the traditional transmission and distribution functionalization used by Duquesne meet FERC's seven-prong test for distribution?

A. Yes. Duquesne applied FERC's seven-prong test to its transmission and distribution systems. Any facility that failed to meet all of the functional criteria for distribution was classified as transmission. As a result, all electric facilities 69KV and above were classified as transmission and all facilities 23KV and below were classified as distribution. There are no facilities between 23KV and 69KV.

Q. Does the traditional functionalization prevent cost-shifting, consistent with the intent of the Act?

A. Yes. Costs are separated into transmission and distribution in a consistent manner as the Company's most recent rate case. However, as Mr. James A. Lahtinen discusses in his testimony, the PaPUC never approved unbundled charges for transmission and distribution in the Company's most recent rate case.

Q. Does this conclude your testimony?

A. Yes, it does.

List of Bob Irvin Exhibits

Exhibit RAI-1	Price Information For PJM Contract
Exhibit RAI-2	PJM Contract Price Calculations
Exhibit RAI-3	Capacity Values During Summer Peak Months
Exhibit RAI-4	RFP And RFP Contract
Exhibit RAI-5	List of Suppliers Receiving RFP
Exhibit RAI-6	Press Release And List Of Trade Publications
Exhibit RAI-7	Copy of Wall Street Journal Advertisement
Exhibit RAI-8	Sample Articles Published In Papers And Trade Press
Exhibit RAI-9	RFP Questions And Duquesne Responses

		Anticipated $	Anticipated MWH	Anticipated $/MWH	Anticipated C.F.(%)	Actual $	Actual MWH	Actual $/MWH	Actual C.F.(%)
Year	MW								
1994	350	63888300	3477600	18.37	100	51956189	2809696	18.49	80.8
1995	300	51098040	2679936	19.07	100	43555518	2258835	19.28	84.3
1996	300	49793143	2635200	18.9	100	48026904	2536628	18.93	96.3
1997	200/100	14511679	828120	17.52	100	8853903	506467	17.48	96.7
						Y.T.D. June	Y.T.D. June	Y.T.D. June	Y.T.D. June

0	1994	ANTICIPATED																TOTAL
	WEEK BEGINNIN	WEEK	MW	DEMAND BLOCK1	MW	DEMAND BLOCK2	TOTAL DEMAND $	HOURS	TOTAL MW	MWH	ON PEAK HOURS	ON PEAK OP.CAP.$ 2.6	ON PEAK ENRGY $ 15.8	OFF PEAK HOURS	OFF PEAK OP.CAP.$ 2	OFF PEAK ENRGY $ 6.8	P.CAP.$ + ENRGY $
MONTH	DAY		BLOCK1	650	BLOCK2	940											
1	3	1	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
1	10	2	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
1	17	3	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
1	24	4	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
1	31	5	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
2	7	6	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
2	14	7	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
2	21	8	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
2	28	9	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
3	7	10	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
3	14	11	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
3	21	12	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
3	28	13	100	65000	350	329000	414000	168	450	75600	80	101250	808250	78	70200	298350	976050
4	4	14	100	65000	350	329000	414000	168	450	75600	80	101250	808250	78	70200	298350	976050
4	11	15	100	65000	350	329000	414000	168	450	75600	80	101250	808250	78	70200	298350	976050
4	18	16	100	65000	350	329000	414000	168	450	75600	80	101250	808250	78	70200	298350	976050
4	25	17	100	65000	350	329000	414000	168	450	75600	80	101250	808250	78	70200	298350	976050
5	2	18	100	65000	300	282000	387000	168	400	67200	80	90000	650000	78	62400	265200	867600
5	9	19	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
5	16	20	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
5	23	21	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
5	30	22	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
6	6	23	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
6	13	24	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
6	20	25	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
6	27	26	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
7	4	27	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
7	11	28	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
7	18	29	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
7	25	30	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
8	1	31	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
8	8	32	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
8	15	33	100	65000	300	282000	387000	168	400	67200	80	90000	650000	78	62400	265200	867600
8	22	34	100	65000	300	282000	387000	168	400	67200	80	90000	650000	78	62400	265200	867600
8	29	35	100	65000	300	282000	387000	168	400	67200	80	90000	650000	78	62400	265200	867600
9	5	36	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
9	12	37	100	65000	300	282000	387000	168	400	67200	80	90000	650000	78	62400	265200	867600
9	19	38	100	65000	300	282000	387000	168	400	67200	80	90000	650000	78	62400	265200	867600
9	26	39	100	65000	300	282000	387000	168	400	67200	80	90000	650000	78	62400	265200	867600
10	3	40	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
10	10	41	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
10	17	42	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
10	24	43	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
10	31	44	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
11	7	45	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
11	14	46	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
11	21	47	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
11	28	48	100	65000	250	235000	320000	168	350	58800	80	78750	363750	78	64800	232050	760150
12	5	49	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
12	12	50	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
12	19	51	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
12	26	52	100	65000	400	376000	481000	168	500	84000	80	112500	882500	78	78000	331500	1084500
							18990000			3477600							44896300
																DEMAND	18990000
																TOTAL $	63886300

0	1995	ANTICIPATED													
	WEEK			DEMAND	DEMAND			ON PEAK	ON PEAK	ON PEAK	OFF PEAK	OFF PEAK	OFF PEAK	P.CAP.$ +
	BEGINNIN	WEEK	MW	$/MW-WK	$	HOURS	MWH	HOURS	OP.CAP.$	ENRGY $	HOURS	OP.CAP.$	ENRGY $	ENRGY $
MONTH	DAY								2.5	12.5		2	8.5	
1	2	1	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
1	9	2	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
1	16	3	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
1	23	4	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
1	30	5	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
2	6	6	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
2	13	7	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
2	20	8	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
2	27	9	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
3	6	10	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
3	13	11	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
3	20	12	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
3	27	13	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
4	3	14	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
4	10	15	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
4	17	16	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
4	24	17	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
5	1	18	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
5	8	19	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
5	15	20	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
5	22	21	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
5	29	22	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
6	5	23	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
6	12	24	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
6	19	25	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
6	26	26	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
7	3	27	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
7	10	28	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
7	17	29	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
7	24	30	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
7	31	31	301	1344	404544	168	50568	80	67726	336826	76	46956	190563	852969
8	7	32	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
8	14	33	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
8	21	34	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
8	28	35	301	1182	355782	168	50568	80	67726	336826	76	46956	190563	852969
9	4	36	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
9	11	37	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
9	18	38	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
9	25	39	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
10	2	40	301	700	210700	168	50568	80	67726	336826	76	46956	190563	852969
10	9	41	301	700	210700	168	50568	80	67726	336826	76	46956	190563	852969
10	16	42	301	700	210700	168	50568	80	67726	336826	76	46956	190563	852969
10	23	43	301	700	210700	168	50568	80	67726	336826	76	46956	190563	852969
10	30	44	301	700	210700	168	50568	80	67726	336826	76	46956	190563	852969
11	6	45	301	862	259462	168	50568	80	67726	336826	76	46956	190563	852969
11	13	46	401	862	345662	168	67368	90	90225	461126	78	62556	265863	869769
11	20	47	401	862	345662	168	67368	90	90225	461126	78	62556	265863	869769
11	27	48	401	862	345662	168	67368	90	90225	461126	78	62556	265863	869769
12	4	49	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
12	11	50	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
12	18	51	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
12	25	52	301	1022	307622	168	50568	80	67726	336826	76	46956	190563	852969
					16498152		2670936							34169040
													DEMAND	16498152
													TOTAL $	51065045

0	1996	ANTICIPATED												
	WEEK			DEMAND	DEMAND			ON PEAK	ON PEAK	ON PEAK	OFF PEAK	OFF PEAK	OFF PEAK	P.CAP.$ +
	BEGINNIN	WEEK	MW	$/MW-WK	$	HOURS	MWH	HOURS	OP.CAP.$	ENRGY $	HOURS	OP.CAP.$	ENRGY $	ENRGY $
MONTH	DAY								2.5	12.5		2	6.5	
1	1	1	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
1	8	2	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
1	15	3	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
1	22	4	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
1	29	5	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
2	5	6	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
2	12	7	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
2	19	8	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
2	26	9	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
3	4	10	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
3	11	11	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
3	18	12	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
3	25	13	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
4	1	14	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
4	8	15	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
4	15	16	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
4	22	17	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
4	29	18	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
5	6	19	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
5	13	20	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
5	20	21	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
5	27	22	300	968	290400	168	50400	90	67500	337500	78	46800	196560	650700
6	3	23	300	1148	343800	168	50400	90	67500	337500	78	46800	196560	650700
6	10	24	300	1148	343800	168	50400	90	67500	337500	78	46800	196560	650700
6	17	25	300	1148	343800	168	50400	90	67500	337500	78	46800	196560	650700
6	24	26	300	1148	343800	168	50400	90	67500	337500	78	46800	196560	650700
7	1	27	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
7	8	28	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
7	15	29	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
7	22	30	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
7	29	31	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
8	5	32	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
8	12	33	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
8	19	34	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
8	26	35	300	1303	390900	168	50400	90	67500	337500	78	46800	196560	650700
9	2	36	300	547	164100	168	50400	90	67500	337500	78	46800	196560	650700
9	9	37	300	547	164100	168	50400	90	67500	337500	78	46800	196560	650700
9	16	38	300	547	164100	168	50400	90	67500	337500	78	46800	196560	650700
9	23	39	300	547	164100	168	50400	90	67500	337500	78	46800	196560	650700
9	30	40	300	547	164100	168	50400	90	67500	337500	78	46800	196560	650700
10	7	41	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
10	14	42	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
10	21	43	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
10	28	44	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
11	4	45	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
11	11	46	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
11	18	47	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
11	25	48	300	672	201600	168	50400	90	67500	337500	78	46800	196560	650700
12	2	49	300	830	249000	168	50400	90	67500	337500	78	46800	196560	650700
12	9	50	300	830	249000	168	50400	90	67500	337500	78	46800	196560	650700
12	16	51	300	830	249000	168	50400	90	67500	337500	78	46800	196560	650700
12	23	52	300	830	249000	168	50400	90	67500	337500	78	46800	196560	650700
12	TWO DAYS	53	300	830	71143	48	14400	30	22500	112500	18	18000	46800	181700
					15788043		2836200							34026100
													DEMAND	15788043
													TOTAL $	49788143

0	1997	ANTICIPATED													
	WEEK			DEMAND	DEMAND			ON PEAK	ON PEAK	ON PEAK	OFF PEAK	OFF PEAK	OFF PEAK	P.CAP.$ +	LOSS
	BEGINNIN	WEEK	MW	$/MW-WK	$	HOURS	MWH	HOURS	OP.CAP.$	ENRGY $	HOURS	OP.CAP.$	ENRGY $	ENRGY $	MWH
MONTH	DAY								2.5	12.5		2	8.5		
1	1	1	200	975	139200	120	24000	75	37500	187500	45	18000	76500	318000	720
1	8	2	200	975	195000	168	33600	90	45000	225000	78	31200	132600	453800	1008
1	13	3	200	975	195000	168	33600	90	45000	225000	78	31200	132600	453800	1008
1	20	4	200	975	195000	168	33600	90	45000	225000	78	31200	132600	453800	1008
1	27	5	200	975	195000	168	33600	90	45000	225000	78	31200	132600	453800	1008
2	3	6	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
2	10	7	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
2	17	8	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
2	24	9	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
3	3	10	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
3	10	11	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
3	17	12	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
3	24	13	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
3	31	14	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
4	7	15	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
4	14	16	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
4	21	17	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
4	28	18	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
5	5	19	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
5	12	20	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
5	19	21	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
5	26	22	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
6	2	23	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
6	9	24	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
6	16	25	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
6	23	26	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
6	30	27	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
7	7	28	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
7	14	29	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
7	21	30	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
7	28	31	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
8	4	32	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
8	11	33	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
8	18	34	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
8	25	35	100	975	97500	168	16800	90	22500	112500	78	15600	66300	216900	504
9	1	36	0	0	0	168	0	90	0	0	78	0	0	0	
9	8	37	0	0	0	168	0	90	0	0	78	0	0	0	
9	15	38	0	0	0	168	0	90	0	0	78	0	0	0	
9	22	39	0	0	0	168	0	90	0	0	78	0	0	0	
9	29	40	0	0	0	168	0	90	0	0	78	0	0	0	
10	6	41	0	0	0	168	0	90	0	0	78	0	0	0	
10	13	42	0	0	0	168	0	90	0	0	78	0	0	0	
10	20	43	0	0	0	168	0	90	0	0	78	0	0	0	
10	27	44	0	0	0	168	0	90	0	0	78	0	0	0	
11	3	45	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
11	10	46	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
11	17	47	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
11	24	48	100	700	70000	168	16800	90	22500	112500	78	15600	66300	216900	504
12	1	49	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
12	8	50	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
12	15	51	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
12	22	52	100	750	75000	168	16800	90	22500	112500	78	15600	66300	216900	504
12	29	53	100	750	33143	72	7200	45	11250	56250	27	5400	23850	96645	216
					4119928		804000							105627750	34120
						LOSSES	34120						DEMAND	4119928	
						TOTAL MWH	838120						TOTAL $	14811678	

DUQUESNE LIGHT COMPANY

Actual Summer Peaking Capacity Purchases

1996

Reservation Price	-	$32,000	- $0.9/MW-HR
Period and Capacity		5 days x 16 hours x 6 weeks x 75 MW	

1997

Preservation Price	-	$52,800	- $1.5/MW-HR
Period and Capacity		5 days x 16 hours x 9 weeks x 50 MW	

REQUEST FOR PROPOSALS

SOLICITATION FOR BIDS TO PURCHASE FIRM POWER FROM DUQUESNE LIGHT COMPANY JUNE 1997

I. INTRODUCTION

Duquesne Light Company (DLC) is offering to sell at wholesale (i) 50 MW of firm electrical capacity and energy ("firm power") for a term of one year, commencing January 1, 1998, and (ii) a minimum of 100 MW, but not more than 500 MW, of firm power for a term of eight years, commencing January 1, 1998. Bids are due June 26, 1997.

II. KEY TERMS AND CONDITIONS

Quantity; Term. Duquesne will sell 50 MW of firm power for a one-year term and a minimum of 100 MW, but not more than 500 MW, for an eight-year term, each term commencing January 1, 1998. Purchasers may submit bids to purchase all or part of the firm power, subject to a 2 MW minimum bid requirement for each sale.

Capacity Factor. During each hour of the contract term, a purchaser must take at least 50% of the contract amount. During each calendar year, a purchaser must take or pay for an amount of energy equal to a 75% annual capacity factor.

Firmness. Duquesne will be obligated to make available the full contract amount to the purchaser, subject to the capacity factors described above. If Duquesne cannot deliver the power scheduled by the purchaser through dispatch of its generation or the purchase of power from third parties, the purchaser will have the right to secure replacement power and Duquesne will reimburse the purchaser for any increased costs associated therewith. In the event neither Duquesne nor the purchaser is able to secure power, the purchaser will receive a credit of $200 for each MWH scheduled but not delivered, with the exception of a failure to deliver due to force majeure.

Price. The winning bidder will pay the price contained in its bid. The one- and eight-year sales require a bid floor of $18/MWH for each year of the contract term.

Commitment to Sell. Provided Duquesne receives sufficient qualifying bids, Duquesne commits to sell 50 MW for one-year and not less than 100 MW for eight years to the highest bidder(s) on a $/MWH basis.

No Duquesne Bids. Neither Duquesne nor any of its affiliates will bid on the sale.

Delivery. Duquesne is not responsible for procuring the necessary transmission and ancillary services on Duquesne's transmission system to resell the power, such responsibility being that of the purchaser or ultimate customer. All service over Duquesne's transmission system shall be governed by Duquesne's FERC-filed tariff, which is identical to FERC's pro forma tariff. Under that tariff, (i) Duquesne's unbundled retail customers are likely to pay for the necessary transmission and distribution charges, such that purchasers reselling power to these customers would be directly responsible only for ancillary service charges (Order 888 specifies which services must be provided by Duquesne), and (ii) the resale of power outside the Duquesne control area requires the purchase of point-to-point service by the purchaser, its agent or the customer to whom the power is resold.

Contract Terms. Each winning bidder will be required to (i) sign a service agreement pursuant to Duquesne's FERC-approved Coordination Sales Tariff ("CST"), and (ii) sign the standard form Power Sale Agreement ("PSA") and Security Addendum enclosed herewith. The CST provides certain general terms and conditions applicable to Duquesne's power sales. The PSA contains terms and prices that are specific to the firm power offered under this RFP. FERC approval is not required for the PSA. (Both the CST and PSA are attached hereto.)

Duquesne Retail Pilot Program. The firm power may be used to serve eligible customers in Duquesne's retail access pilot program, which is scheduled to commence November 1, 1997. If bidders are interested in purchasing firm power for November-December 1997 for use in the pilot program, Duquesne is willing to negotiate arrangements comparable

to those offered here for that two-month period. The negotiations would occur outside the RFP process and therefore potential bidders need not submit bids for this period in their bid forms.

III. RULES FOR SUBMITTING BIDS

Eligibility. To be eligible, a bidder must be able to demonstrate creditworthiness consistent with Section 4.2 of the CST, submit a bid that conforms to the Bid Form attached hereto, agree to resell the power, and satisfy all the other criteria contained in the RFP.

Multiple Bids. A bidder may submit one or more bids; each bid, however, must conform to the following requirements.

Fixed Contract Amount. Each bid must be for a fixed number of MW for the entire contract term (i.e., the MW cannot vary by year).

Minimum Bid Quantity. Each bid must be for a minimum of 2 MW.

Reductions in Bid Amounts. All bids shall be "up to" bids, such that Duquesne may award a bidder an amount (in MW) less than offered if necessary to avoid selling more power than Duquesne has committed to sell in the RFP. (For bidders that offer to purchase more than 10 MW, however, their bids will not be reduced to less than 10 MW.) Any bids conditioned on a contrary requirement that Duquesne accept the entire bid amount, without the possibility of reduction, will be rejected as deficient. The following examples illustrate the bid selection process for the one-year sale:

Example 1

Bid	Bid Amount	Bid Price	MWs Awarded
Bid A	5 MW	$21/MWH	5 MW
Bid B	3 MW	$20/MWH	3 MW
Bid C	20 MW	$19 MWH	20 MW
Bid D	30 MW	$18/MWH	22 MW
Total MW Awarded			50 MW

Example 2

Bid	Bid Amount	Bid Price	MWs Awarded
Bid A	20 MW	$21/MWH	20 MW
Bid B	20 MW	$20/MWH	20 MW
Bid C	5 MW	$19/MWH	5 MW
Bid D	20 MW	$18/MWH	10 MW[1]
Total MW Awarded			55 MW

Fixed Annual Bid Price. Each bid must contain a single fixed price (in $/MWH) for each year of the contract term, although prices may vary by year. Bids may not be tied to an index.

Bid Evaluation. DLC will award the firm power to the highest bid(s) on a $/MWH basis, not a total revenue basis. For example, a 10 MW bid @ $23/MWH will be ranked higher than a 40 MW bid @ $22/MWH. The eight-year sale bids will be ranked on a present value basis (7.94% discount rate).

Minimum Bid Price. The minimum bid price for the one- and eight-year sales is $18/MWH each year of the contract term.

Authorization. Proposals must be signed by an officer of the entity submitting the bid and must contain an irrevocable offer to purchase firm power in the quantity awarded (up to the quantity of the bid) and at the prices contained in the bid.

Term of Offer. Bids must remain valid through July 17, 1997, the date on which an executed service agreement and PSA from each winning bidder must be received by Duquesne.

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[1] Bidder D is awarded 10 MW because it has offered to purchase more than 10 MW.

Questions and Comments; Revisions. Bidders may submit written questions or comments regarding the RFP or PSA to Robert A. Irvin, Duquesne Light Company, 411 Seventh Ave., Pittsburgh, Pa. 15230 (facsimile 412-393-8647). No oral questions or comments will be answered. All responses to written questions or comments will be published on the DLC System Operations Internet page (www.soc-dlco.lm.com) as soon as possible after receipt. Duquesne reserves the right to modify the RFP or PSA to reflect any such comments. Any modifications will be publicly disseminated sufficiently in advance of the bid due date to allow potential bidders to take such modifications into account in preparing their bids. Any such changes will be posted on the aforementioned Internet page.

Confidentiality. DLC may disclose the bids only to: (i) DLC employees (on a need to know basis and in conformance with all applicable codes of conduct); (ii) consultants and attorneys retained by DLC, and (iii) a judicial or administrative body if ordered to do so. Duquesne also reserves the right to disclose the bid prices and terms of sale to DLC's regulators without reference to the identity of the bidders.

IV. BIDDING HYPOTHETICAL

A. Sample Bids; Bid Evaluation

The following are three sample bids for the eight-year sale and the manner in which Duquesne will evaluate them. (The prices are examples; they do not represent a price stream preferred by DLC.) The bids (in $/MWH) are as follows:

Bid; Amount	1998	1999	2000	2001	2002	2003	2004	2005
Bid A (50 MW)	21.00	22.00	24.00	24.50	26.00	27.00	29.00	31.00
Bid B (100 MW)	21.00	22.00	24.00	25.50	27.00	28.00	30.00	32.00
Bid C (70 MW)	18.50	19.00	23.00	26.00	30.00	33.00	35.00	38.00

The format of each bid is acceptable, given that each uses a fixed price ($/MWH) per year, each bid exceeds the $18/MWH floor, and each bid specifies a single contract amount (in MW) for the entire contract

term. The price streams offered by the bidders convert to the following nominal levelized payments:

Bid	Levelized Price[2]	MW Bid	MW Awarded
Bid A	$25.02/MWH	50 MW	0
Bid B	$25.57/MWH	100 MW	30 MW
Bid C	$26.62/MWH	70 MW	70 MW

As the table indicates, "Bid C" is the highest on a present value basis and therefore is awarded the first block of firm power (70 MW) at the prices contained in that bid. The residual 30 MW is awarded to the next highest bid, "Bid B." Although Bid B offered to purchase 100 MW, it will be awarded 30 MW at the prices contained in its bid if Duquesne decides to sell only the minimum amount (100 MW). Also as indicated, Bid A receives no award of firm power.

B. Sample Payments

Each calendar year, purchasers must take or pay for energy in an amount equal to a 75% annual capacity factor. The next table illustrates the annual amounts and payments for the winning bidders in the previous example. The first set of rows indicates the annual take or pay amount, using the capacity awarded to each bid and a 75% annual capacity factor. The second set of rows indicates the total annual

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[2] The levelized price is determined by calculating the present value of the contract price stream and solving for the single price for all years of the contract that will yield the same present value. Duquesne will use a 7.94% discount rate to calculate the present values.

payments by each bidder, using these annual energy amounts and the winning bid prices.

	1998	1999	2999	2991	2992	2003	2004	2005
Annual MWH								
Bid B (30 MW)	197,100	197,100	197,100	197,100	197,100	197,100	197,100	197,100
Bid C (70 MW)	459,900	459,900	459,900	459,900	459,900	459,900	459,900	459,900
Annual Payment ($000)								
Bid B	4,139	4,336	4,730	5,026	5,322	5,519	5,913	6,307
Bid C	8,508	8,738	10,578	11,957	13,797	15,177	16,097	17,476

V. SCHEDULE

The following is the RFP schedule:

Date	Event
June 26, 1997	An original, signed bid must be received in the offices of Duquesne Light Company, 411 Seventh Ave., Pittsburgh, Pa. 15230 (attention: Robert A. Irvin) no later than 12:00 noon (EDT). No facsimiles will be accepted.
July 1, 1997	DLC will notify bidders in writing of any omissions, deficiencies or requests for credit information. DLC will use facsimile numbers provided by bidders; otherwise, notification will be via overnight mail or courier.
July 8, 1997	A signed original of any bid supplements to cure omissions or deficiencies must be received in the offices of Duquesne (address and person indicated above) by 12:00 noon (EDT).

July 11, 1997	DLC will announce the winning bidder(s) and submit a PSA and a service agreement under the CST (to those that have not already executed same) to each winning bidder for execution. The agreements will be delivered to the bidders by overnight mail or courier for receipt no later than July 14, 1997.
July 18, 1997	An original executed service agreement and PSA from each winning bidder must be received in the offices of Duquesne (address and person indicated above) by 12:00 noon (EDT).

BID FORM[1]

Bidder, _____, a [corporation] organized and operating under the laws of _____, hereby offers to purchase firm power at wholesale from Duquesne Light Company ("Duquesne") in accordance with the requirements of the Request for Proposals ("RFP") issued in June 1997 and the terms contained herein:

1. General Terms. Bidder offers to purchase firm power from Duquesne pursuant to the terms of the Power Sale Agreement ("PSA"), which was enclosed with the RFP, as supplemented by the specific terms contained herein. If Bidder's offer is accepted by Duquesne pursuant to the terms specified herein, Bidder agrees to execute, without modification other than as necessary to complete missing information, the standard form PSA and, if not yet executed, the standard form service agreement under the Coordination Sales Tariffs on or before July 18, 1997.

2. Specific Terms.

Term. Bidder offers to purchase firm power for a term of __[2] year[s], commencing January 1, 1998, in the amounts and at the prices specified herein.

Bid Amount. Bidder offers to purchase __ MW of firm power ("Offer Amount") in each year of the contract term from Duquesne. Bidder authorizes Duquesne to award to Bidder an amount less than the Offer Amount pursuant to the terms of the RFP, provided that if the Offer Amount exceeds 10 MW and a portion (but not all) of the Offer Amount qualifies for an award, Duquesne will not reduce an award to less than 10 MW. Bidder understands and agrees that, with respect to that portion of the Offer Amount which qualifies for an award, the PSA requires the purchaser to (i) schedule at least 50% of that

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1 Bidders may submit one or more bids; however, each bid must conform to the requirements of the RFP.

2 Bidder should insert either "eight" or "one" for the term of the sale for which the bid is being submitted.

amount each hour during the contract term, and (ii) take or pay for an amount of energy equal to a 75% annual capacity factor.

Bid Prices. Bidder offers to purchase firm power at the prices, measured in $/MWH, specified below for the corresponding calendar year(s) during the contract term, such firm power to be taken or paid for on the basis of a 75% annual capacity factor:[3]

1998	1999	2000	2001	2002	2003	2004	2005

3. Credit. Bidder provides the following information on its credit rating or such other information establishing Bidder's creditworthiness:

_____

_____

4. Resale of Power. Bidder is offering to purchase firm power at wholesale and warrants that, if its bid is accepted in whole or in part, Bidder will resell all firm power delivered by Duquesne.

5. Revocability; Term. This offer is irrevocable by Bidder through July 18, 1997.

6. Authorization. The undersigned is an officer of Bidder authorized to submit this offer, and to bind Bidder to its terms.

[Full Corporate Name of Bidder]:

By: _____
(signature)

Title: _____

Date: _____

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[3] Bidder should fill in (i) only the first year (1998) if the bid is for the one-year sale, or (ii) all eight-years if the bid is for the eight-year sale. The minimum bid price for all years is $18/MWH.

POWER SALE AGREEMENT
(Firm Power for a One-Year Term)

This Power Sales Agreement ("Agreement") is entered into on the __ day of ___ 1997 by and between Duquesne Light Company ("Duquesne"), a corporation organized and operating under the laws of Pennsylvania, and _____ ("Purchaser"), a corporation organized and operating under the laws of _____ (together, "the Parties").

W I T N E S S E T H:

WHEREAS, in June 1997 Duquesne issued a request for proposals seeking bids on the wholesale sale by Duquesne of firm electrical capacity and energy ("Firm Power") for a one-year term;

WHEREAS, Purchaser submitted a bid and was selected as a winning bidder;

WHEREAS, Duquesne has authority from the Federal Energy Regulatory Commission ("FERC") to sell Firm Power at wholesale pursuant to a Coordination Sales Tariff ("CST"), provided that (i) the purchaser signs a standard form service agreement that commits the Purchaser to abide by the terms of the CST, and (ii) Duquesne and the Purchaser agree to terms for each transaction entered into thereunder; and

WHEREAS, Purchaser has executed a service agreement under the CST and Duquesne and Purchaser further have agreed to the transaction-specific terms set forth in this Agreement:

NOW, THEREFORE, Duquesne and Purchaser hereby agree as follows:

ARTICLE I
RELATIONSHIP TO CST

1.1 CST Obligations. The sale of Firm Power by Duquesne to Purchaser under this Agreement shall be a sale of "negotiated capacity and energy" under the CST and shall be governed by the terms of the CST (attached hereto as Exhibit II), as further supplemented by the transaction-specific terms contained herein. An executed standard form service agreement under the CST is attached hereto (Exhibit III), signifying the Parties' agreement to be bound by the terms of the CST.

1.2 Rates. The rates for the sale of Firm Power under this Agreement shall be exclusively those set forth in this Agreement.

1.3 Amendments to the CST. If Duquesne submits to FERC, and FERC approves, an amendment to the CST, such amendment shall not be binding on Purchaser, and the provisions of the CST in effect on the Effective Date of this Agreement shall continue to bind the Parties, unless Purchaser, in its sole discretion, agrees in writing to such amendment.

ARTICLE II
EFFECTIVE DATE; TERM

2.1 Effective Date. Subject to the condition precedent of FERC acceptance of a standard form service agreement between Duquesne and Purchaser under the CST, the effective date of this Agreement is midnight December 31, 1997 ("Effective Date").

2.2 Term. The term of this Agreement shall commence on the Effective Date and shall terminate at midnight December 31, 1998 ("Contract Term"). Such termination shall not relieve Purchaser of the obligation to pay any charges incurred during the Contract Term.

ARTICLE III
CONTRACT AMOUNT; CAPACITY FACTOR; SCHEDULING

3.1 Contract Amount. Subject to Purchaser meeting its obligations under this Agreement, Duquesne shall make available to Purchaser __ MW (hereinafter "Contract Amount") of Firm Power in each hour during the Contract Term. Duquesne shall have no obligation under this Agreement to make available any amounts in excess of the Contract Amount in any hour.

3.2 Capacity Factor.

(a) During each hour of the Contract Term, Purchaser shall schedule, and accept delivery of, at least 50% percent of the Contract Amount.

(b) During the Contract Term, and irrespective of whether Purchaser schedules and accepts delivery of such amount, Purchaser shall pay for an amount of energy ("Take or Pay Amount" or "TPA"), measured in megawatt-hours, as specified below:

TPA = (Contract Amount)(.75)(HY[1])

Duquesne shall not be obligated under this Agreement to deliver energy in excess of the Take or Pay Amount during the Contract Term.

3.3 Scheduling.

(a) Purchaser shall submit a schedule, specifying the amount of power (in whole megawatts) to be delivered each hour, no later than 10:00 a.m. of the day prior to the day for which delivery is requested. Schedule changes shall be accepted in accordance with standard industry operating practices.

(b) Unless otherwise agreed by the Parties, for each week of the Contract Term, Purchaser shall, no later than Thursday at 12:00 noon of the previous week, submit a nonbinding schedule of the amount of

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[1] HY means hours in the year, which shall be 8760 for each year other than a leap year; HY in a leap year shall be 8784.

power (in whole megawatts) to be delivered each hour during the following calendar week (commencing the following Monday at 12:01 a.m.). This nonbinding schedule shall be Purchaser's good faith estimate of its requirements for the following week and shall not bind Purchaser with respect to the schedules required under Section 3.3(a).

(c) Other scheduling and operating protocols may be adopted by mutual agreement of the Parties.

ARTICLE IV
NON-DELIVERY

4.1 Replacement Power.

(a) If Duquesne fails to deliver the Firm Power scheduled by Purchaser in accordance with Sections 3.2 and 3.3(a), Purchaser may procure replacement power for such amounts. Duquesne will reimburse Purchaser for the amount, if any, by which the Replacement Power Cost exceeds the Purchase Price in the hours and for the amounts of Firm Power scheduled in accordance with Sections 3.2 and 3.3(a) but not delivered. Replacement Power Cost means (i) the cost of power purchased to replace the Firm Power scheduled in accordance with Sections 3.2 and 3.3(a) but not delivered by Duquesne, inclusive of energy charges and demand charges, provided that only a pro rata share of such demand charges shall qualify as Replacement Power Costs where such demand charges also apply to deliveries other than replacement power under this Agreement, and (ii) any increase in transmission service costs incurred by Purchaser to deliver the replacement power, provided that any additional transmission service purchased for that purpose is used to deliver replacement power to the same delivery point(s) at which Purchaser would have delivered Firm Power had it been supplied by Duquesne as scheduled.

(b) Purchaser shall submit verification of such replacement power costs to Duquesne and Duquesne shall not be responsible for reimbursement of such costs until such verification is received. Any reimbursement shall take the form of a credit to Purchaser's bill(s) sufficient to reimburse Purchaser for such replacement costs.

(c) Duquesne's obligation to provide a credit for replacement power under this Section is contingent upon Purchaser having used commercially reasonable efforts to procure replacement power at the lowest available cost.

4.2 No Replacement Power Available.

(a) Except where such failure is due to Force Majeure, if Duquesne fails to deliver Firm Power scheduled in accordance with Sections 3.2 and 3.3(a), and Purchaser is unable in good faith to procure replacement power, Purchaser shall receive a credit of $200/MWH for each MWH scheduled in accordance with Sections 3.2 and 3.3(a) but which Duquesne failed to deliver.

(b) If, because of Force Majeure, Duquesne is unable to deliver Firm Power scheduled by Purchaser in accordance with Sections 3.2 and 3.3(a), Duquesne will be excused from providing the billing credits set forth in this Section 4.2, provided that: (i) the suspension of delivery is no greater in scope and no longer in duration than is required by the Force Majeure; and (ii) Duquesne uses commercially reasonable efforts to overcome the effects of the Force Majeure, provided, however, that under no circumstances shall Duquesne be required to settle any any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of Duquesne, are contrary to its interest. As used herein, "Force Majeure" means any occurrence beyond the reasonable control of, and without the fault or negligence of, Duquesne that causes Duquesne to be unable to deliver the Firm Power scheduled by Purchaser in accordance with Sections 3.2 and 3.3(a), including, but not limited to, fires, floods, earthquakes or other acts of God, labor disputes, actions or inactions by Federal, state and municipal agencies, and actions or inactions of legislative, judicial or regulatory agencies.

4.3 Notice. Duquesne shall notify Purchaser by telephone or facsimile, or by another equally expeditious medium, if and when Duquesne has reason to believe that it will be unable to deliver the power scheduled by Purchaser pursuant to Section 3.3(a).

4.4 Sole Remedy. Notwithstanding any other provision of this Agreement or any provision of the CST,

the remedies provided in this Article for the non-delivery by Duquesne of Firm Power scheduled by Purchaser in accordance with this Agreement shall be the sole remedies available to Purchaser for such non-delivery.

ARTICLE V
PAYMENT OBLIGATIONS; BILLING

5.1 Purchase Price. For all amounts of energy scheduled and delivered under this Agreement, and for any additional amounts of energy up to the Take or Pay Amount, Purchaser shall pay $__ MWH ("Purchase Price").

5.2 Billing. The rendering of bills, and any defaults related to the failure to pay such bills, is governed by Section 4.3 and 4.4 of the CST. If, at the end of the Contract Term, the amount of energy scheduled and taken by Purchaser during the Contract Term, and for which Purchaser has or will be billed under the provisions of the CST, is less than the Take or Pay Amount, Duquesne shall include in the bill for the last calendar month of the Contract Term charges applicable to the remaining amount of energy for which Purchaser must pay up to the Take or Pay Amount.

ARTICLE VI
POWER DELIVERY; TRANSMISSION SERVICE

6.1 Delivery.

(a) Delivery of Firm Power under this Agreement shall be at a point or points on the Duquesne Transmission System as mutually agreed by the Parties or such other delivery points as agreed by the Parties ("Points of Delivery"), provided, however, that in no event shall Duquesne be responsible for the purchase of transmission service on the Duquesne Transmission System to effect such delivery unless otherwise agreed by the Parties. "Duquesne Transmission System" shall mean the transmission facilities owned by Duquesne at or above 69 kilovolts.

(b) Unless otherwise agreed by the Parties, Duquesne shall be responsible for all costs, liabilities, losses, taxes and charges of any kind for the delivery or sale of Firm Power up to the Points of Delivery, and Purchaser shall be responsible for all costs,

liabilities, losses, taxes and charges of any kind for the redelivery or resale of Firm Power after receipt at the Points of Delivery.

6.2 Transmission and Ancillary Services. Unless otherwise agreed by the Parties, Duquesne shall not be responsible for procuring transmission and ancillary services that are necessary for the resale of power delivered under this Agreement. Duquesne shall not be obligated to deliver Firm Power in any hour unless the necessary transmission and ancillary service arrangements have been made. Upon Duquesne's request, Purchaser shall provide to Duquesne evidence that the necessary transmission and ancillary service arrangements have been made.

ARTICLE VII
OTHER TERMS

7.1 Representations and Warranties.

(a) Duquesne hereby represents and warrants to Purchaser that (i) Duquesne is a validly existing corporation with full authority to enter into this Agreement, (ii) Duquesne has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery hereof, this Agreement shall be a legally binding obligation of Duquesne, (iii) Duquesne has secured all necessary governmental or regulatory approvals, with the exception of FERC approval of the standard form service agreement under the CST for which Duquesne shall promptly apply after its execution.

(b) Purchaser hereby represents and warrants to Duquesne that: (i) Purchaser is a validly existing [corporation/partnership/other] with full authority to enter into this Agreement, (ii) Purchaser has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery hereof, this Agreement shall be a legally binding obligation of Purchaser, (iii) Purchaser has secured all necessary governmental or regulatory approvals, and (iv) Purchaser will resell all Firm Power purchased under this Agreement.

7.2 Controlling Law. The validity, interpretation and effect of this Agreement are governed by

the laws of the Commonwealth of Pennsylvania applicable to contracts made and performed in such State and without regard to conflicts of law doctrines, except to the extent preempted by Federal law or governed by the law of the jurisdiction of organization of the respective Parties.

7.3 Amendment. No modification or amendment of this Agreement shall be effective unless it is in writing and signed on behalf of both Parties.

7.4 Entire Agreement. This Agreement, together with the CST, the standard form service agreement under the CST, and the Security Addendum, shall constitute the entire agreement of the Parties and shall supersede any other agreement, whether written or oral, of the Parties regarding the sale of Firm Power that is the subject of this Agreement.

7.5 Incorporation by Reference. The provisions of Sections 4.4 ("Defaults"), 4.8 ("Successors and Assigns"), 4.9 ("Rights Restriction"), and 4.10 ("Waivers") of the CST, and paragraph 5 of Exhibit A (relating to notices) of the standard form service agreement under the CST, are hereby incorporated by reference and made a part of this Agreement, and for such purposes, references in such Sections to the "tariff" shall be deemed to refer to this Agreement.

IN WITNESS WHEREOF, intending to be legally bound, the Parties have caused this Agreement to be entered into by their duly authorized officers and attested to by their respective secretaries, as of the day and year first above written.

DUQUESNE LIGHT COMPANY

By:_____ Attest:_____

Title:_____ Title:_____

[PURCHASER]

By:_____ Attest:_____

Title:_____ Title:_____

POWER SALE AGREEMENT
(Firm Power for an Eight-Year Term)

This Power Sales Agreement ("Agreement") is entered into on the __ day of ___ 1997 by and between Duquesne Light Company ("Duquesne"), a corporation organized and operating under the laws of Pennsylvania, and _____ ("Purchaser"), a corporation organized and operating under the laws of _____ (together, "the Parties").

W I T N E S S E T H:

WHEREAS, in June 1997 Duquesne issued a request for proposals seeking bids on the wholesale sale by Duquesne of firm electrical capacity and energy ("Firm Power") for an eight-year term;

WHEREAS, Purchaser submitted a bid and was selected as a winning bidder;

WHEREAS, Duquesne has authority from the Federal Energy Regulatory Commission ("FERC") to sell Firm Power at wholesale pursuant to a Coordination Sales Tariff ("CST"), provided that (i) the purchaser signs a standard form service agreement that commits the Purchaser to abide by the terms of the CST, and (ii) Duquesne and the Purchaser agree to terms for each transaction entered into thereunder; and

WHEREAS, Purchaser has executed a service agreement under the CST and Duquesne and Purchaser further have agreed to the transaction-specific terms set forth in this Agreement:

NOW, THEREFORE, Duquesne and Purchaser hereby agree as follows:

ARTICLE I
RELATIONSHIP TO CST

1.1 CST Obligations. The sale of Firm Power by Duquesne to Purchaser under this Agreement shall be a sale of "negotiated capacity and energy" under the CST and shall be governed by the terms of the CST (attached hereto as Exhibit II), as further supplemented by the transaction-specific terms contained herein. An executed standard form service agreement under the CST is attached hereto (Exhibit III), signifying the Parties' agreement to be bound by the terms of the CST.

1.2 Rates. The rates for the sale of Firm Power under this Agreement shall be exclusively those set forth in this Agreement.

1.3 Amendments to the CST. If Duquesne submits to FERC, and FERC approves, an amendment to the CST, such amendment shall not be binding on Purchaser, and the provisions of the CST in effect on the Effective Date of this Agreement shall continue to bind the Parties, unless Purchaser, in its sole discretion, agrees in writing to such amendment.

ARTICLE II
EFFECTIVE DATE; TERM

2.1 Effective Date. Subject to the condition precedent of FERC acceptance of a standard form service agreement between Duquesne and Purchaser under the CST, the effective date of this Agreement is midnight December 31, 1997 ("Effective Date").

2.2 Term. The term of this Agreement shall commence on the Effective Date and shall terminate at midnight December 31, 2005 ("Contract Term"). Such termination shall not relieve Purchaser of the obligation to pay any charges incurred during the Contract Term.

ARTICLE III
CONTRACT AMOUNT; CAPACITY FACTOR; SCHEDULING

3.1 Contract Amount. Subject to Purchaser meeting its obligations under this Agreement, Duquesne shall make available to Purchaser __ MW (hereinafter "Contract Amount") of Firm Power in each hour during the Contract Term. Duquesne shall have no obligation under this Agreement to make available any amounts in excess of the Contract Amount in any hour.

3.2 Capacity Factor.

(a) During each hour of the Contract Term, Purchaser shall schedule, and accept delivery of, at least 50% percent of the Contract Amount.

(b) During each calendar year of the Contract Term, and irrespective of whether Purchaser schedules and accepts delivery of such amount in that calendar year, Purchaser shall pay for an amount of energy ("Take or Pay Amount" or "TPA"), measured in megawatt-hours, as specified below:

TPA = (Contract Amount)(.75)(HY[1])

Duquesne shall not be obligated under this Agreement to deliver, on a calendar year basis, energy in excess of the Take or Pay Amount.

3.3 Scheduling.

(a) Purchaser shall submit a schedule, specifying the amount of power (in whole megawatts) to be delivered each hour, no later than 10:00 a.m. of the day prior to the day for which delivery is requested. Schedule changes shall be accepted in accordance with standard industry operating practices.

(b) Unless otherwise agreed by the Parties, for each week of the Contract Term, Purchaser shall, no later than Thursday at 12:00 noon of the previ-

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[1] HY means hours in the year, which shall be 8760 for each year other than a leap year; HY in a leap year shall be 8784.

ous week, submit a nonbinding schedule of the amount of power (in whole megawatts) to be delivered each hour during the following calendar week (commencing the following Monday at 12:01 a.m.). This nonbinding schedule shall be Purchaser's good faith estimate of its requirements for the following week and shall not bind Purchaser with respect to the schedules required under Section 3.3(a).

(c) Other scheduling and operating protocols may be adopted by mutual agreement of the Parties.

ARTICLE IV
NON-DELIVERY

4.1 Replacement Power.

(a) If Duquesne fails to deliver the Firm Power scheduled by Purchaser in accordance with Sections 3.2 and 3.3(a), Purchaser may procure replacement power for such amounts. Duquesne will reimburse Purchaser for the amount, if any, by which the Replacement Power Cost exceeds the Purchase Price in the hours and for the amounts of Firm Power scheduled in accordance with Sections 3.2 and 3.3(a) but not delivered. Replacement Power Cost means (i) the cost of power purchased to replace the Firm Power scheduled in accordance with Sections 3.2 and 3.3(a) but not delivered by Duquesne, inclusive of energy charges and demand charges, provided that only a pro rata share of such demand charges shall qualify as Replacement Power Costs where such demand charges also apply to deliveries other than replacement power under this Agreement, and (ii) any increase in transmission service costs incurred by Purchaser to deliver the replacement power, provided that any additional transmission service purchased for that purpose is used to deliver replacement power to the same delivery point(s) at which Purchaser would have delivered Firm Power had it been supplied by Duquesne as scheduled.

(b) Purchaser shall submit verification of such replacement power costs to Duquesne and Duquesne shall not be responsible for reimbursement of such costs until such verification is received. Any reimbursement shall take the form of a credit to Purchaser's bill(s) sufficient to reimburse Purchaser for such replacement costs.

(c) Duquesne's obligation to provide a credit for replacement power under this Section is contingent upon Purchaser having used commercially reasonable efforts to procure replacement power at the lowest available cost.

4.2 No Replacement Power Available.

(a) Except where such failure is due to Force Majeure, if Duquesne fails to deliver Firm Power scheduled in accordance with Sections 3.2 and 3.3(a), and Purchaser is unable in good faith to procure replacement power, Purchaser shall receive a credit of $200/MWH for each MWH scheduled in accordance with Sections 3.2 and 3.3(a) but which Duquesne failed to deliver.

(b) If, because of Force Majeure, Duquesne is unable to deliver Firm Power scheduled by Purchaser in accordance with Sections 3.2 and 3.3(a), Duquesne will be excused from providing the billing credits set forth in this Section 4.2, provided that: (i) the suspension of delivery is no greater in scope and no longer in duration than is required by the Force Majeure; and (ii) Duquesne uses commercially reasonable efforts to overcome the effects of the Force Majeure, provided, however, that under no circumstances shall Duquesne be required to settle any any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of Duquesne, are contrary to its interest. As used herein, "Force Majeure" means any occurrence beyond the reasonable control of, and without the fault or negligence of, Duquesne that causes Duquesne to be unable to deliver the Firm Power scheduled by Purchaser in accordance with Sections 3.2 and 3.3(a), including, but not limited to, fires, floods, earthquakes or other acts of God, labor disputes, actions or inactions by Federal, state and municipal agencies, and actions or inactions of legislative, judicial or regulatory agencies.

4.3 Notice. Duquesne shall notify Purchaser by telephone or facsimile, or by another equally expeditious medium, if and when Duquesne has reason to believe that it will be unable to deliver the power scheduled by Purchaser pursuant to Section 3.3(a).

4.4 Sole Remedy. Notwithstanding any other provision of this Agreement or any provision of the CST,

the remedies provided in this Article for the non-delivery by Duquesne of Firm Power scheduled by Purchaser in accordance with this Agreement shall be the sole remedies available to Purchaser for such non-delivery.

ARTICLE V
PAYMENT OBLIGATIONS; BILLING

5.1 Purchase Price. For all amounts of energy scheduled and delivered under this Agreement, and for any additional amounts of energy up to the Take or Pay Amount, Purchaser shall pay the following rates ("Purchase Price") for the corresponding calendar year of delivery during the Contract Term:

Year	Charge
1998	$ MWH
1999	$ MWH
2000	$ MWH
2001	$ MWH
2002	$ MWH
2003	$ MWH
2004	$ MWH
2005	$ MWH

5.2 Billing. The rendering of bills, and any defaults related to the failure to pay such bills, is governed by Section 4.3 and 4.4 of the CST. If, at the end of any calendar year during the Contract Term, the amount of energy scheduled and taken by Purchaser for that year, and for which Purchaser has or will be billed under the provisions of the CST, is less than the Take or Pay Amount, Duquesne shall include in the bill for the last calendar month of that year charges applicable to the remaining amount of energy for which Purchaser must pay up to the Take or Pay Amount.

ARTICLE VI
POWER DELIVERY; TRANSMISSION SERVICE

6.1 Delivery.

(a) Delivery of Firm Power under this Agreement shall be at a point or points on the Duquesne Transmission System as mutually agreed by the Parties or such other delivery points as agreed by the Parties ("Points of Delivery"), provided, however, that in no event shall Duquesne be responsible for the purchase of transmission service on the Duquesne Transmission System to effect such delivery unless otherwise agreed by the Parties. "Duquesne Transmission System" shall mean the transmission facilities owned by Duquesne at or above 69 kilovolts.

(b) Unless otherwise agreed by the Parties, Duquesne shall be responsible for all costs, liabilities, losses, taxes and charges of any kind for the delivery or sale of Firm Power up to the Points of Delivery, and Purchaser shall be responsible for all costs, liabilities, losses, taxes and charges of any kind for the redelivery or resale of Firm Power after receipt at the Points of Delivery.

6.2 Transmission and Ancillary Services. Unless otherwise agreed by the Parties, Duquesne shall not be responsible for procuring transmission and ancillary services that are necessary for the resale of power delivered under this Agreement. Duquesne shall not be obligated to deliver Firm Power in any hour unless the necessary transmission and ancillary service arrangements have been made. Upon Duquesne's request, Purchaser shall provide to Duquesne evidence that the necessary transmission and ancillary service arrangements have been made.

ARTICLE VII
OTHER TERMS

7.1 Representations and Warranties.

(a) Duquesne hereby represents and warrants to Purchaser that (i) Duquesne is a validly existing corporation with full authority to enter into this Agreement, (ii) Duquesne has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery hereof, this Agreement shall be a legally binding obligation of Duquesne, (iii) Duquesne has secured all necessary gov-

ernmental or regulatory approvals, with the exception of FERC approval of the standard form service agreement under the CST for which Duquesne shall promptly apply after its execution.

(b) Purchaser hereby represents and warrants to Duquesne that: (i) Purchaser is a validly existing [corporation/partnership/other] with full authority to enter into this Agreement, (ii) Purchaser has taken all necessary measures to have the execution and delivery of this Agreement authorized, and upon the execution and delivery hereof, this Agreement shall be a legally binding obligation of Purchaser, (iii) Purchaser has secured all necessary governmental or regulatory approvals, and (iv) Purchaser will resell all Firm Power purchased under this Agreement.

7.2 Controlling Law. The validity, interpretation and effect of this Agreement are governed by the laws of the Commonwealth of Pennsylvania applicable to contracts made and performed in such State and without regard to conflicts of law doctrines, except to the extent preempted by Federal law or governed by the law of the jurisdiction of organization of the respective Parties.

7.3 Amendment. No modification or amendment of this Agreement shall be effective unless it is in writing and signed on behalf of both Parties.

7.4 Security. The Parties shall provide such security as is required by the Security Addendum attached hereto as Exhibit I.

7.5 Entire Agreement. This Agreement, together with the CST, the standard form service agreement under the CST, and the Security Addendum, shall constitute the entire agreement of the Parties and shall supersede any other agreement, whether written or oral, of the Parties regarding the sale of Firm Power that is the subject of this Agreement.

7.6 Incorporation by Reference. The provisions of Sections 4.4 ("Defaults"), 4.8 ("Successors and Assigns"), 4.9 ("Rights Restriction"), and 4.10 ("Waivers") of the CST, and paragraph 5 of Exhibit A (relating to notices) of the standard form service agreement under

the CST, are hereby incorporated by reference and made a part of this Agreement, and for such purposes, references in such Sections to the "tariff" shall be deemed to refer to this Agreement. As used in this Section 7.6 and in Sections 7.2 and 7.3 above, references to "this Agreement" shall include the Security Addendum.

IN WITNESS WHEREOF, intending to be legally bound, the Parties have caused this Agreement to be entered into by their duly authorized officers and attested to by their respective secretaries, as of the day and year first above written.

DUQUESNE LIGHT COMPANY

By:_____ Attest:_____

Title:_____ Title:_____

[PURCHASER]

By:_____ Attest:_____

Title:_____ Title:_____

EXHIBIT I TO POWER SALE AGREEMENT
SECURITY ADDENDUM

This Security Addendum ("Addendum") is entered into on the __ day of ___ 1997 by and between Duquesne Light Company ("Duquesne"), a corporation organized and operating under the laws of Pennsylvania, and _____ ("Purchaser"), a corporation organized and operating under the laws of _____ (together, "the Parties").

W I T N E S S E T H:

WHEREAS, Duquesne and Purchaser have executed a Power Sale Agreement ("PSA") under which Duquesne has agreed to sell, and Purchaser has agreed to purchase, __ MW of Firm Power; and

WHEREAS, as security for the prompt and complete payment by Purchaser of all sums due under the PSA, and the performance by Duquesne of its delivery obligations under the PSA, the Parties have agreed to the terms of a security arrangement set forth in this Addendum:

NOW, THEREFORE, Duquesne and Purchaser hereby agree as follows:

ARTICLE I
DEFINITIONS

Collateral means (i) cash in U.S. dollars, or (ii) an irrevocable standby letter of credit in favor of Pledgee issued by a bank, and in a form, acceptable to Pledgee.

Collateral Amount means the absolute value of the Contract-to-Market Amount.

Contract-to-Market Amount means the Remaining Obligation minus the Market Rate.

Contract Term has the meaning ascribed thereto in the PSA.

Duquesne Collateral Account means the account maintained by Duquesne in the name "Duquesne Light Company, as pledgee from [name of Purchaser]" at [name of bank] or such other similarly captioned account as Duquesne may specify in writing.

Effective Date has the meaning ascribed thereto in the PSA.

Firm Power has the meaning ascribed thereto in the PSA.

Investment Grade means a security that is rated higher than Ba1 by Moody's Investors Service or higher than BB+ by Standard & Poors Ratings Group.

Market Rate means the present value, using a discount rate of 7.94%, of the product of (i) the rate prevailing in the market as of the Notice Date for electric capacity and energy similar in firmness, capacity factor and other material respects to the Firm Power sold to Purchaser under the PSA, and (ii) the number of megawatt-hours representing a 75% annual capacity factor for the period from the Notice Date to the end of the Contract Term.

Notice Date has the meaning ascribed thereto in Section 2.4(a) hereof.

Pledgee means Duquesne if the Contract-to-Market Amount is positive and means Purchaser if the Contract-to-Market Amount is negative.

Pledgor means Purchaser if the Contract-to-Market Amount is positive and means Duquesne if the Contract-to-Market Amount is negative.

Purchase Price has the meaning ascribed thereto in the PSA.

Purchaser Collateral Account means the account maintained by the Purchaser in the name "[name of Purchaser], as pledgee from Duquesne Light Company" at [name of bank] or such other similarly captioned account as Purchaser may specify in writing.

Remaining Obligation means the present value, using a discount rate of 7.94%, of the product of (i) the number of megawatt-hours representing a 75% annual capacity factor for the period from the Notice Date to the end of the Contract Term, and (ii) the Purchase Price applicable to each such MWH under the terms of the PSA.

ARTICLE II
SECURITY REQUIREMENTS

2.1 Effective Date; Term. This Addendum shall take effect on the Effective Date and shall have a term coincident with the Contract Term.

2.2 Security Interest. As security for the prompt and complete payment of all amounts due or that may become due from Pledgor to Pledgee, and the performance by Pledgor of all covenants and obligations under this Addendum and the PSA, Pledgor hereby pledges, assigns, conveys and transfers to Pledgee, and grants to Pledgee a first priority continuing security interest in and to, and a general first lien upon and right of set-off against, all Collateral which is delivered or transferred to Pledgee or its agent pursuant to the provisions of this Addendum.

2.3 Triggering Events.

(a) If at any time during the Contract Term, (i) Duquesne's senior debt securities are below Investment Grade, and (ii) the Contract-to-Market Amount is negative in the amount of at least $10 million, Purchaser may, in its sole discretion, require Duquesne to provide the Collateral Amount as security for the performance of Duquesne's obligations under the PSA. Purchaser shall provide such notice and its determination of the Contract-to-Market Amount in writing to Duquesne.

(b) If at any time during the Contract Term, (i) Purchaser's senior debt securities are below Investment Grade, and (ii) the Contract-to-Market Amount is positive in the amount of at least $10 million, Duquesne may, in its sole discretion, require Purchaser to provide the Collateral Amount as security for payment of all amounts due under the PSA. Duquesne shall provide such notice and its determination of the Contract-to-Market Amount in writing to Purchaser.

2.4 Determination of Market Rate.

(a) The Pledgee shall determine, in good faith and using commercially reasonable methods, the Market Rate, and if as the result of such determination the Pledgee would be entitled to receive the Collateral Amount pursuant to Section 2.3 above, Pledgee may notify the Pledgor of such

determination and that the Pledgor is required to provide the Collateral Amount (the date of such notification, the "Notice Date").

(b) If within five (5) days after the Notice Date the Pledgor notifies the Pledgee that the Pledgor objects to such determination, and the Parties fail to agree on a Market Rate within ten (10) days after the Notice Date, the Parties shall appoint three (3) independent market experts who shall determine the Market Rate, such experts being knowledgeable regarding the markets for the sale of electric power. If the Parties fail to agree on such experts within fifteen (15) days after the Notice Date, each of the Parties shall, within five (5) days thereafter, appoint one (1) independent market expert, and the two (2) experts so appointed shall select a third independent market expert. The three (3) independent market experts so selected shall, within twenty (20) days of the selection of the third expert, agree upon and provide in writing to the Parties a Market Rate for use in calculation of the Contract-to-Market Amount, which rate shall be binding on the Parties. If the Pledgor fails to notify the Pledgee within five (5) days after the Notice Date that the Pledgor objects to the Pledgee's determination of the Market Rate, or fails to select an independent market expert within the time requirements of this Section 2.4(b), then the Market Rate determined by Pledgee pursuant to Section 2.4(a) shall be binding on the Parties.

(c) All costs of the use of the independent market experts pursuant to Section 2.4(b) above shall be shared equally by the Parties; provided, however, that each Party shall be responsible for all costs of preparing or presenting its own position to the independent market experts, including the costs of its own counsel and/or consultants.

2.5 Delivery of Collateral. If Pledgor is required under this Addendum to deliver Collateral to Pledgee, Pledgor shall do so (a) within five (5) days after the Notice Date, or (b) if Pledgor gives notice of its objection to the Pledgee's determination of the Market Rate within said five (5) day period, then within two (2) business days after the later of (i) agreement by the Parties on the Market Rate, or (ii) the date on which the Pledgor receives a determination of the Market Rate from the independent market experts. Within the time periods specified in this

Section 2.5, Pledgor shall pay or deliver, or cause to be paid or delivered, to Pledgee, or its agent for the safekeeping of such Collateral, the Collateral. All cash Collateral delivered by the Purchaser shall be delivered by wire transfer of immediately available funds to the Duquesne Collateral Account. The original executed copies of all letters of credit to be delivered by the Purchaser shall be physically delivered to Duquesne or any agent specified by it. All cash Collateral delivered by Duquesne shall be delivered by wire transfer of immediately available funds to the Purchaser Collateral Account. The original executed copies of all letters of credit to be delivered by Duquesne shall be physically delivered to the Purchaser or any agent specified by it.

2.6 Administration of Collateral.

(a) Pledgee shall be under no obligation to pay Pledgor any interest or dividends with respect to the Collateral. All principal and interest paid to or received by Pledgee and/or its agent for safekeeping, in respect of Collateral held by Pledgee and/or its agent for safekeeping, shall be held or retained as additional Collateral subject to this Addendum and shall be subject to the security interest in, general first lien on and right of set-off against, such Collateral granted pursuant hereto in favor of Pledgee.

(b) Beyond the exercise of reasonable care in the custody thereof, Pledgee shall have no duty as to any Collateral in its possession or control or in the possession or control of any agent or bailee or any income thereon or as to the preservation of rights against prior parties or any other rights pertaining thereto. Pledgee shall be deemed to have exercised reasonable care in the custody and preservation of the Collateral in its possession, and/or in the possession of its agent for safekeeping, if the Collateral is accorded treatment substantially equal to that which it accords its own property, and shall not be liable or responsible for any loss or damage to any of the Collateral, or for any diminution in the value thereof, by reason of the act or omission of any agent for safekeeping of Pledgee selected by Pledgee in good faith except to the extent such loss or damage is the result of such agent's recklessness, willful misconduct or bad faith.

(c) Cash Collateral held by Duquesne as Pledgee shall be maintained in the Duquesne Collateral Account. Cash Collateral held by the Purchaser as Pledgee shall be maintained in the Purchaser Collateral Account. Pledgee shall at all times retain possession or control of non-cash Collateral delivered to it and/or its agent for safekeeping, provided that any agent for safekeeping must be an affiliate of the Pledgee, and shall not repledge or transfer any such Collateral to any person other than a person acting as the agent of Pledgee for safekeeping or otherwise deal with any Collateral delivered to it.

(d) The holding of Collateral by an agent for safekeeping for the benefit of a Pledgee shall be deemed to be the holding and possession of such Collateral by the Pledgee for the purpose of perfecting the security interest in the Collateral. Nothing in this Addendum shall be construed as requiring a Pledgee to select an agent for safekeeping of Collateral for the benefit of such Pledgee.

2.7 Exercise of Rights Against Collateral. In the event of a default under the PSA or the Coordination Sales Tariff (attached to the PSA as Exhibit II), Pledgee may exercise, in addition to any other right or remedy at law or in equity, the following rights and remedies:

(a) all rights and remedies available to a secured party under the Uniform Commercial Code of the state in which the Collateral is being held and other applicable laws with respect to the Collateral held by or for the benefit of Pledgee; and

(b) the right to set-off any Collateral held by or for the benefit of Pledgee against and in satisfaction of any amount payable by Pledgor in respect of any of its obligations under the PSA.

Pledgor shall in all events remain liable to Pledgee for any of its obligations remaining unpaid after any application of such Collateral.

2.8 Return or Adjustment of Collateral.

(a) If on any date subsequent to the Notice Date, Pledgor's senior debt securities return to Investment Grade, Pledgee, within two (2) business days of receiving notice from Pledgor of same, shall pay or return, or cause

to be paid or returned, all Collateral previously delivered by Pledgor to Pledgee or its agent under this Addendum that has not been required to satisfy obligations of Pledgor under the PSA.

(b) At any time after the Pledgee has held the same Collateral Amount for a period of at least six months, either Party may require a new determination of the Market Rate if such Party determines that the Collateral Amount then being held by the Pledgee is at least $5 million greater or less than the then current Contract-to-Market Amount and so notifies the other Party. The date of such notice will be treated as a "Notice Date" for purposes of applying the procedures in Section 2.4(b) above, and the Market Rate determined in accordance with such procedures shall thereupon become binding on the Parties for use in calculation of the Contract-to-Market Amount. If the resulting Contract-to-Market Amount is less than $5 million are no amounts payable by Pledgor to Pledgee under the PSA that are overdue, or other obligations of Pledgor to Pledgee that Pledgor has failed to perform in a timely fashion, Pledgee shall pay or return, or cause to be paid or returned, all Collateral previously delivered by Pledgor to Pledgee or its agent under this Addendum that has not been required to satisfy obligations of Pledgor under the PSA.

(c) Upon (i) the termination of the PSA and (ii) the performance by Pledgor of all of its obligations under the PSA, Pledgee shall pay or return, or cause to be paid or returned, all Collateral previously delivered by Pledgor to Pledgee or its agent under this Addendum that has not been required to satisfy obligations of Pledgor under the PSA.

(d) If at any time all remaining Collateral is to be paid or returned to Pledgor pursuant to this Section 2.8, Pledgee shall, at the request and expense of Pledgor, execute and deliver to Pledgor such documentation as is necessary or appropriate to release the liens created by this Security Addendum.

2.9 Miscellaneous.

(a) Pledgor will defend the Collateral against the claims and demands of all other parties, will keep all Collateral free from all security interests or other encumbrances (except the security interest hereunder)

and will not sell, transfer, assign, deliver or otherwise dispose of any Collateral or any interest therein without the prior written consent of Pledgee.

(b) Pledgor will execute and deliver to Pledgee (and to the extent permitted by applicable law, Pledgor hereby authorizes Pledgee to execute and deliver, in the name of Pledgor or otherwise) such financing statements, assignments and other documents and do such other things relating to the Collateral and the security interest granted under this Addendum including any action necessary or appropriate to perfect or maintain perfection of Pledgee's security interest in the Collateral, and Pledgor shall pay all costs relating thereto.

IN WITNESS WHEREOF, intending to be legally bound, each of the Parties hereto has caused this Addendum to be executed on its behalf by its duly authorized officer and attested to by its corporate secretary, as of the day and year first above written.

DUQUESNE LIGHT COMPANY

By:_____ Attest:_____

Title:_____ By:_____

[PURCHASER]

By:_____ Attest:_____

Title:_____ By:_____

ARTICLE I

AVAILABILITY

Section 1.1 This tariff is applicable to coordination sales by Duquesne Light Company ("DLC") of capacity and/or energy for resale to any entity, including, without limitation, any electric utility, municipality, exempt wholesale generator, qualifying facility, federal power marketing agency, power marketers, or any other entity engaged in the sale for resale of electric energy or capacity.

Section 1.2 Each entity that desires to take service under this tariff shall sign a Service Agreement in the form attached hereto. A purchaser of capacity and/or energy pursuant to this tariff is referred to herein as a "Customer." DLC and a Customer are sometimes referred to in this tariff as a "Party" or the "Parties."

ARTICLE II

OPERATIONS

Section 2.1 Points of Delivery - The points of delivery for coordination sales by DLC will be mutually agreed upon by DLC and the customer.

Section 2.2 Ownership and Maintenance - Neither Party shall have any responsibility under this tariff to install, operate or maintain the other Party's facilities for or on behalf of the other Party or any other entity.

Section 2.3 Character of Power and Energy - All capacity and/or energy delivered pursuant to this tariff shall be three-phase, 60-cycle capacity and/or energy.

Section 2.4 Reactive Power - Neither Party shall be obligated to deliver reactive power to the other Party or to receive reactive power from the other Party when to do so may introduce detrimental operating conditions on the system of either Party.

ARTICLE III

SERVICE TO BE RENDERED

Section 3.1 Coordination Sales - This tariff establishes a framework under which DLC may sell and a Customer may purchase capacity and/or energy from time to time for their mutual benefit. Additional terms and conditions applicable to such transactions are established by the following attached service schedules:

Service Schedule	Type of Service
A	Negotiated Capacity and/or Energy
B	Emergency Energy

DLC will file with the Commission a Service Agreement signed by each customer who takes service under the tariff.

Section 3.2 Relationship to Other Agreements - This tariff does not govern and shall not affect sales or transmission of capacity and/or energy under any other agreement between the Parties.

Section 3.3 Delivery and Transmission Arrangements - All deliveries of capacity and/or energy shall be made at the points of delivery as agreed to by the Parties. Unless otherwise mutually agreed upon when a transaction is arranged, DLC shall be responsible for making all arrangements necessary for transmission of capacity and/or energy provided hereunder to the points of delivery and for all costs, including losses associated with such transmission, and the Customer shall be responsible for all such arrangements and costs for the transmission of capacity and/or energy from the points of delivery.

Section 3.4 Scheduling - All capacity and/or energy shall be delivered on a scheduled basis in accordance with the applicable service schedule. Scheduling requests shall be initiated by the Customer. Except by mutual agreement, schedules shall be set according to DLC's standard scheduling procedures; provided that DLC shall use reasonable efforts to accommodate a Customer's requests for nonconforming schedules or schedule changes. All schedules shall be in whole megawatt quantities unless modified by mutual agreement to reflect losses. Each Party shall provide to the other Party the names and/or positions of persons authorized to coordinate transaction schedules on its behalf.

Section 3.5 Emission Allowances - Service Schedules A and B shall be deemed to include the cost of emission allowances which are utilized in the production of electric energy under provisions of the Federal Clean Air Act. The terms and conditions for the supply of such allowances shall be as set forth in Appendix 90CAAA, attached to the tariff and shall be effective from time to time as filed with and approved by the FERC.

Section 3.6 Facilities - Services rendered shall not require DLC to construct or install any new facilities.

ARTICLE IV

GENERAL PROVISIONS

Section 4.1 Rate Schedule Changes - DLC shall have the right unilaterally at any time to make application to the FERC, pursuant to Section 205 of the Federal Power Act and the FERC's applicable rules and regulations, for changes in any of the rates, terms or conditions of this tariff. Any such changes in this tariff of a term of one year or less shall not affect transactions agreed to by the Parties prior to the date such changes become effective.

Section 4.2 Credit Appraisal Criteria - DLC has the right to request the following information from any Customer applying for service under this tariff:

(a) current financial statements, annual reports, other publicly available reports and filings;

(b) a bank reference and trade references; and

(c) verification of the Customer's solvency.

The Customer may elect to provide one of the following guarantee of payment options in lieu of providing requested financial data:

(a) an irrevocable letter of credit acceptable to DLC;

(b) a security interest in collateral found by DLC to be acceptable; or

(c) a guarantee by a person or another entity who satisfies DLC's credit appraisal criteria.

Should a Customer fail to meet DLC's credit appraisal criteria and should a Customer fail to provide one of the guarantee payment options above, DLC may refuse service until such time as DLC is assured, to DLC's sole satisfaction, of the Customer's ability to pay.

Additionally, DLC may request any other information that DLC determines to be reasonably required to evaluate the Customer's application and/or continued eligibility for service.

The above steps are necessary to prudently review the credit worthiness of new customers before DLC commits significant resources to a sale.

Section 4.3 Billing - The Customer shall compensate DLC for all purchases in accordance with the terms of the applicable service schedule in effect at the time of delivery. All bills for coordination sales provided under this tariff shall be issued on a calendar month basis, by the 5th working day following the calendar month to which they apply. All bills shall be due and payable within 15 days after receipt; provided that, in no event shall any payment be due before the 20th day of the billing month. If the due date of a payment is a Saturday, Sunday or Federal legal holiday, the bill shall be paid on or before the next following business day. Interest on any unpaid amounts shall accrue at the then prime rate (or comparable rate) per annum of Manufacturers Hanover Trust Company from the due date of the bill until the date of receipt of payment.

Section 4.4 Defaults - Upon the failure of a Customer to pay all amounts as to which there is no dispute within 30 days of the date on which a payment is due, the Customer is in default and (a) DLC may immediately cease making coordination sales to the Customer under this tariff until the default is cured; (b) the Customer shall not contest or object to the suspension of its right to schedule energy hereunder; (c) DLC may terminate its obligations under this tariff; (d) DLC may initiate any regulatory or legal proceeding necessary to terminate the Customer's service under this tariff and to obtain payment of all amounts due; and (e) DLC may exercise any other remedy available at law or in equity. If it becomes necessary to terminate the customer service, DLC will file the appropriate termination notices with all regulatory agencies having jurisdiction.

Section 4.5 Liability - DLC shall not be liable to a Customer, or its customers, in the event DLC is prevented, in whole or in part, from making any coordination sales by any cause beyond DLC's reasonable control, including but not limited to, outages or interruptions due to weather, accidents, equipment failures, repairs, inspections, strikes, civil unrest, injunctions or actions or inactions of any governmental authority having jurisdiction. If DLC's performance has been prevented by such an event, it shall promptly and diligently attempt to remove the cause of its failure to perform, except that DLC shall not be obligated to agree to any settlement of a strike or labor disturbance which, in its opinion, may be inadvisable or detrimental. DLC shall continue to perform after such cause has been removed. DLC shall have no liability to a

Customer or its customers for any direct or indirect, incidental, consequential, special, loss of use, loss of revenue or loss of profit or any other damages which may arise from any cause, however arising.

Section 4.6 Indemnity - Each Party agrees to defend, indemnify and hold harmless the other Party against all claims, liability, loss, damage or expense of any other entity caused by, or resulting from, negligent acts or omissions of the indemnifying Party, its employees or agents.

Section 4.7 Records - The Parties shall maintain records of all transactions for a period of at least three years after the cancellation or termination of this tariff. Each Party shall make such records available for inspection and audit by the other Party at reasonable times and places at the other Party's request; provided, however, that all bills for sales made under this tariff shall become final for all purposes, and not subject to audit or adjustment, on the one-year anniversary of their issuance dates.

Section 4.8 Successors and Assigns - This tariff shall be binding upon the Parties, their successors and assigns, on and after its effective date. Service under this tariff shall not be assigned in whole or in part by either Party to any other entity without the prior written consent of the other Party, which shall not be unreasonably withheld.

Section 4.9 Rights Restriction - This tariff is not intended to, and shall not create rights of any type whatsoever in favor of any person, corporation, association or entity other than the Parties, and the obligations assumed herein are solely for the use and benefit of such Parties.

Section 4.10 Waivers - Any waiver at any time by either Party of its rights with respect to failure to comply with the terms of this tariff or with respect to any other matter arising in connection with this tariff shall not be deemed a waiver with respect to any subsequent failure to comply with such matters or any other matter. Any delay in asserting or enforcing any right under this tariff shall not be deemed a waiver of such right.

Section 4.11 Notices - All notices provided to DLC under this tariff shall be addressed as follows:

Vice President - Power Supply Group
Duquesne Light Company
411 Seventh Avenue
Pittsburgh, Pennsylvania 15219

DLC may designate an alternate representative or change the position and address each as specified above by written notice to the Customer.

Section 4.12 Regulation - This tariff is subject to acceptance for filing by the FERC.

Section 4.13 Effective Date; Termination - This tariff shall become effective on the date as assigned by the FERC. Until terminated, service under this tariff shall continue in full force and effect and, following termination, the provisions of this tariff related to Billing, Liability, Indemnity and Records shall survive until the Parties' obligations thereunder have been fully discharged.

Section 4.14 Article and Section Headings - The headings contained in this tariff are used solely for convenience and are not intended to be used in any manner in the interpretation of this tariff.

SERVICE SCHEDULE A

NEGOTIATED CAPACITY AND/OR ENERGY

SECTION 1 - DURATION

1.1 This Service Schedule A, a part of the Coordination Sales Tariff, shall continue in effect throughout the duration of the Coordination Sales Tariff, unless and until changed pursuant to the tariff.

SECTION 2 - SERVICES TO BE RENDERED

2.1 A Customer may purchase Negotiated Capacity and/or Energy from DLC for the purpose of obtaining a supply of power during the period covered by a commitment. It is intended to provide both the Customer and DLC with a wide range of flexibility in structuring transactions which are mutually beneficial, including negotiated degrees of firmness, reserve responsibility, capacity and energy charges and variable time durations.

SECTION 3 - CONDITIONS OF SERVICE

3.1 A Customer may request the number of megawatts and the period for which it desires to reserve Negotiated Capacity. DLC shall, based upon its sole judgment, promptly indicate the extent of its ability and willingness to make the requested reservation and the capacity charge, if any, which will be applicable. Any request, acknowledgment of such request, offer and/or acceptance of any offer given orally shall be confirmed in writing within five (5) business days following the oral request, acknowledgment, offer or acceptance, unless mutually agreed otherwise by the parties.

3.2 The degree of firmness of the Negotiated Capacity, which may range from firmness equivalent to DLC's native requirements services to non-firm service, shall be mutually agreed upon by both Parties at the time the power is reserved. Capacity classified as non-firm shall, at a minimum, be treated by DLC as having a higher degree of reliability than sales to other systems which do not involve a sale of capacity.

3.3 During the period that firm Negotiated Capacity has been reserved as provided above, it shall be the responsibility of the Customer to schedule in advance, the deliveries of energy associated therewith and of DLC to deliver such energy in amounts up to the number of megawatts reserved.

3.4 The Negotiated Capacity billing demand for any period shall be equal to the number of megawatts reserved for such period as Negotiated Capacity.

SECTION 4 - COMPENSATION

4.1 Compensation for the supply of Negotiated Capacity and/or Energy shall be at the following rates:

4.11 Capacity generated by DLC:

a. Up to $132,360/MW-year for periods of up to one (1) year;

b. Up to $11,030/MW-month for periods of three (3) through eleven (11) months;

c. Up to $2,545/MW-week for periods of one (1) through twelve (12) weeks;

d. Up to $509/MW-day for periods of less than one (1) week; provided, however, this element of the charge for any one (1) week shall total no more than the product of $2,545 times the highest average number of megawatts delivered in any hour during the week; or

e. Up to $31.80/MW-hour for periods of less than one (1) day; provided, however, this element of the charge for one (1) day shall be no greater than $509 times the highest average number of megawatts delivered in any one (1) hour during the day or $2,545 times the highest average number of megawatts delivered in any one hour in a consecutive seven (7) day period.

4.12 Energy Charge

a. The energy charge for all megawatt hours generated and delivered by DLC under this Service Schedule A shall be DLC's Incremental Costs (IC) plus an adder of up to 10% of IC. The IC for SO_2 allowances shall be determined as provided for in Appendix 90CAAA attached hereto.

b. Upon request by a Customer, an estimate of energy charges will be given prior to scheduling of energy for any given day, and the Customer will be notified of any significant changes to that price.

4.13 Transmission Charges

a. When required, transmission and related ancillary services may be arranged for by the Customer pursuant to the prevailing DLC Open Access Transmission Tariff, FERC Docket OA-96-56-000.

b. Transmission required for DLC to supply capacity and/or energy to the Customer under this schedule will be priced pursuant to the prevailing DLC Open Access Transmission Tariff, FERC Docket OA-96-56-000.

The Transmission Price for Non-Firm Point-To-Point Transmission Service shall be up to the sum of the applicable charges set forth below:

1. Monthly delivery: $1.63/KW of Reserved Capacity per month.

2. Weekly delivery: $0.38/KW of Reserved Capacity per week.

3. Daily delivery: $0.054/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4. Hourly delivery: The basic charge in no event shall exceed $2.23/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5. Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own transactions, the Transmission Provider must offer at the same

time the same discounted Non-Firm Point-to-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any non-firm transmission discounts must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

SERVICE SCHEDULE B

EMERGENCY ENERGY

SECTION 1 - DURATION

1.1 This Service Schedule B, a part of the Coordination Sales Tariff, shall continue in effect throughout the duration of the Coordination Sales Tariff, unless and until changed pursuant to the Tariff.

SECTION 2 - SERVICES TO BE RENDERED

2.1 Emergency Energy is non-firm energy made available from time to time by DLC from generating capacity on its system or from energy purchased from another entity when an emergency exists on the system of the Customer. An emergency is a breakdown or other contingency involving either sources of power or transmission facilities, or both, which impairs or jeopardizes the Customer's ability to meet its system requirements.

2.2 The Customer may request the provision of Emergency Energy by specifying to DLC the amount of energy it desires to purchase and the period for which it desires the energy. DLC shall furnish Emergency Energy in such amounts and for such periods as, in its sole judgment, it can supply or purchase.

2.3 DLC may curtail, restrict or discontinue delivery of Emergency Energy whenever, in its sole judgment, such curtailment, restriction or discontinuance is necessary in order to meet the requirements of its native load customers and/or other customers. Notice of such curtailment, restriction or discontinuance shall be made by expeditious means to the Customer as far in advance as practicable, and the Customer shall promptly comply with the decision of DLC.

SECTION 3 - COMPENSATION

3.1 The rates for Emergency Energy generated by DLC shall be the greater of:

3.11 a. $100 per megawatt-hour; or

b. 110% of DLC's Incremental Costs (IC). The IC for SO_2 allowances shall be determined as provided for in Appendix 90CAAA attached hereto.

3.12 Transmission Charges

a. When required, transmission and related ancillary services may be arranged for by the Customer pursuant to the prevailing DLC Open Access Transmission Tariff, FERC Docket OA-96-56-000.

b. Transmission required for DLC to supply capacity and/or energy to the Customer under this schedule will be priced pursuant to the prevailing DLC Open Access Transmission Tariff, FERC Docket OA-96-56-000.

The Transmission Price for Non-Firm Point-To-Point Transmission Service shall be up to the sum of the applicable charges set forth below:

1. Monthly delivery: $1.63/KW of Reserved Capacity per month.

2. Weekly delivery: $0.38/KW of Reserved Capacity per week.

3. Daily delivery: $0.054/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above *times the highest amount in kilowatts of Reserved Capacity in any day* during such week.

4. Hourly delivery: The basic charge in no event shall exceed $2.23/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5. Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own transactions, the Transmission Provider must offer at the same time the same discounted Non-Firm Point-to-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any non-firm transmission discounts must be posted on the OASIS

pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

Service Agreement
Duquesne Light Company
Coordination Sales Tariff

Agreement made this _____day of _____ 19__, by and between the Duquesne Light Company (DLC) and the _____, a _____ corporation (hereinafter 'the Customer'). In consideration of the mutual covenants and agreements herein, and intending to be legally bound, the Parties hereby agree as follows:

1. DLC shall supply services under its Coordination Sales Tariff dated _____ and accepted by FERC Letter Order dated _____ at Docket No._____.

2. The Customer shall pay DLC for the services rendered in accordance with the provisions of its Coordination Sales Tariff as currently on file with FERC, and as currently in effect, or as it may be amended from time to time.

3. This Agreement incorporates by reference all the provisions of DLC's Coordination Sales Tariff as they exist or as they may be amended from time to time.

4. This Agreement is made subject to acceptance of all the provisions hereof by any governmental authority or authorities having jurisdiction, including the FERC, without change or condition unacceptable to DLC.

5. Exhibit A, as currently attached hereto and as it may be amended from time to time, shall provide points of contact for notice, scheduling and billing of transactions under this Service Agreement.

In witness whereof, the undersigned have caused this Agreement to be executed by their duly authorized representatives on the date first written above.

Attest: Duquesne Light Company

_____ By:_____

Title:_____

Attest: Customer

_____ By:_____

Title:_____

1. Any notice given pursuant to this Agreement shall be in writing as follows:

If to DLC:

Vice President - Power Supply Group
Duquesne Light Company
411 Seventh Avenue
Pittsburgh, PA 15219

If to Customer: _____
_____
_____
_____

2. Scheduling under this Agreement will be accomplished between the following dispatch centers:

Duquesne Light Company
Pittsburgh, PA
(412) 471-3832

Customer:

_____
_____
_____
_____

3. Billing for services provided to the purchaser under this Agreement will be coordinated between:

Duquesne Light Company
2839 New Beaver Avenue
Pittsburgh, PA 15233
Attention: Manager, System Operations
(412) 393-8222

Customer:

_____
_____
_____
_____

APPENDIX 90CAAA

Section 1. The calculation of "Out-of-Pocket" and "Incremental" costs shall be deemed to include the cost of emission allowances which are utilized in the production of electric energy under provisions of the federal Clean Air Act, as amended, 42 U.S.C. § 7401 et. seq. (hereinafter referred to as "Clean Air Act").

Section 2. When the Duquesne Light Company (DLC) is the supplying Party, the following guidelines will be implemented for coordination sales requiring the use of emission allowances:

A. Emission Allowances for Coordination Sales

DLC will determine emissions allowance costs on the basis of the emission allowance index published monthly by Emission Exchange Corporation. Both coordination sales pricing and dispatch decisions are based on this index by the inclusion of the appropriate ¢/MMBTU of emission allowance costs into the incremental cost of each affected unit. The appropriate ¢/MMBTU emission allowance cost is based upon the emission rate of the corresponding unit.

B. Election to Supply Emission Allowances

For each transaction, the purchaser shall make an election no later than the beginning of the coordination transaction as to whether it will supply the associated emission allowances or have the allowances supplied by DLC. The cost of allowances supplied by DLC will be billed in the current billing cycle. DLC is indifferent as to the purchaser's election to either supply or pay for emission allowances.

Allowances supplied by the purchaser must be supplied to DLC by December 31 of the current year. If the purchaser fails to supply DLC the allowances by December 31, the purchaser will pay DLC the cost to obtain the allowances plus a 10% adder will be included to

cover those costs which are hard to quantify. If after best efforts DLC cannot obtain the required allowances, the purchaser will reimburse DLC for all fines and penalties occurred under the provisions of the 1990 Clean Air Act Amendments due to the purchaser's failure to supply allowances, plus the cost of any allowances forfeited in future years due to the purchaser's inability to fulfill its commitment and 110% of associated legal fees.

C. **Calculation of Emission Allowances to be Supplied by the Purchaser**

For each hour in which there is a transaction for energy or capacity services, and in which the purchaser is supplying the emissions allowances, DLC will:

(1) identify the generation sources used and the amount of energy or capacity provided by those sources for the transaction;

(2) for those sources requiring emission allowances under the 1990 Clean Air Act Amendments, determine the amount of emission allowances utilized for the transaction using the formula:

[MMBTU sale - MMBTU no sale][SO_2], where MMBTU sale = Million BTU consumed with the transaction, MMBTU no sale = Million BTU consumed without the transaction and [SO_2] = Tons of SO_2 per MMBTU; and

(3) reduce the transaction pricing by the cost of allowances calculated in C(2).

(4) Emission Allowances between 0.001 and 0.449 shall be rounded to zero and Emission Allowances between 0.500 and 0.999 shall be rounded to 1. This rounding method shall apply to both cash and traded allowance type transactions.

Acme Power Marketing, Inc.
ATTN: c/o Patrick Lynch @ Dickstein-Shapiro
2101 L Street, NW,
Washington, DC 20037

AES Power, Inc.
ATTN: Hugh D. Baker, Jr.
1001 North 19th Street,
Arlington, VA 22209

AIG Trading Company
ATTN: Michael A. Goldstein
One Greenwich Plaza,
Greenwich, CT 06830

Alliance Strategies
ATTN: J. Tim Watson
16861 SW Martinazzi Avenue, Suite 203E
Tualatin, OR 97062

Alternate Power Source, Inc.
ATTN: Stephen Tuleja, President
200 Clarendon Street,
Boston, MA 02116

American Power Exchange Corporation
ATTN: Eric Patterson
9040 Executive Park Drive, Suite 315
Knoxville, TN 37923

AMOCO Power Marketing Corporation
ATTN: Frederick T. Kolb
501 Westlake Park Boulevard,
Houston, TX 77079

ANP Energy Direct Company
ATTN: Elaine G. Rollins
10000 Memorial Drive, Suite 500
Houston, TX 77024

Aquila Power Corporation
ATTN: Jerry F. Coffey
2533 North 117th Avenue,
Omaha, NE 68164

Ark Exploration Company (took over NorAm)
ATTN: SEE NoRam

Ashton Energy Corp.
ATTN: Stephen B. Richards, Senior VP
3100 Wilcrest Drive, Suite 220
Houston, TX 77042

Associated Power Services
ATTN: George W. Drake
Two Warren Place, 6120 South Yale, Suite 1200
Tulsa, OK 74136

Astra Power, Inc.
ATTN: Rita Sharp, Vice President
818 Kansas Ave,
Topeka, KS 66601

Audit Pro, INc.
ATTN: James Keene
World Trade Center, Suite 114
San Francisco, CA 94111

Black Creek Hydro, Inc.
ATTN: Martin W. Thompson, V.P.
19515 North Creek Parkway, Suite 310
Bothell, WA 98011

Bonneville Fuels Management Corporation
ATTN: Roger Swenson
50 West 300 South, Suite 600
Salt Lake City, UT 84101

Boyd Rosenne & Associates
ATTN: Mr. Michael K. Boyd
1200 Park Center, 525 South Main Street
Tulsa, OK 74103

Btu Power, Inc.
ATTN: Robert Divers, Vice President
777-108th Avenue NE,
Bellevue, WA 98004

C.C. Pace Energy Servcies
ATTN: Paul Meyers
4375 Fair Lakes Court, Suite 2000
Fairfax, VA 22033

Calpine Power Marketing, Inc.
ATTN: Clifford M. Naeve @ Skadden, Arps, Slate, et al
1440 New York Avenue, NW,
Washington, DC 20005

Camelot Energy Services
ATTN: Dennis M. Lawler
2555 Talbots Lane,
Brookfield, WI 53045

Catex Vitol Electric, Inc.
ATTN: Michael R. Kutsch, President
470 Atlantic Avenue,
Boston, MA 02210

Cenergy, Inc.
ATTN: Thomas J. Lewis, President
1 Main Street, S.E., Suite 600
Minneapolis, MN 55414

Cenerprise, Inc.
ATTN: Stephen J. Beuning, Director
One Main Street, SE, Suite 600
Minneapolis, MN 55414

Chicago Energy Exchange of Chicago, Inc.
ATTN: Gregory E. Elam, President
205 North Michigan Avenue, Illinois Center, Suite 4315
Chicago, IL 60601

Citizens Energy Corporation
ATTN: John P. Williams
530 Atlantic Avenue,
Boston, MA 02210

Citizens Lehman Power LP
ATTN: Joseph C. Bell @ Hogan & Hartson
555 Thirteenth Street, NW,
Washington, DC 20004

Citizens Power and Light Corporation
ATTN: Barry Sheingold, Senior VP
530 Atlantic Avenue,
Boston, MA 02210

CMEX Energy, Inc. (SEE "GLOBAL PETROL")
ATTN: Ron Bates, V.P. Corporate Development
17101 Preston Road, Suite 240
Dallas, TX 75248

CNB/Olympic Gas Services
ATTN: Darin Cook
14 East University Avenue, Suite 213
Gainsville, FL 32601

Coastal Electric Services Company
ATTN: Eric Brown, General Counsel
9 Greenway Plaza,
Houston, TX 77046

CoEnergy Trading Company
ATTN: Glen D. Kinder, President
150 W. Jefferson, Suite 1600
Detroit, MI 48226

Cogentrix Energy Power Marketing, Inc.
ATTN: Dennis W. Alexander
9405 Arrowpoint Boulevard,
Charlotte, NC 28273

ConAgra Energy Services
ATTN: Jean E. Connolly, General Counsel
Nine ConAgra Drive,
Omaha, NE 68102

Conoco Power Marketing, Inc.
ATTN: Gordon E. Goodman, President
600 North Dairy Ashford, Suite PR-2066
Houston, TX 77210

Consolidated Natural Gas (CNG) Power Services Corp
ATTN: Thomas E. Dodd
One Park Ridge Center, P.O. Box 15746
Pittsburgh, PA 15244

Continental Energy Services
ATTN: Paul S. Bahra
37543 East Greenwood,
Northville, MI 48167

Coral Power, Inc.
ATTN: Charles J. McClees, Jr., Esq.
200 North Dairy Ashford, Suite 2236
Houston, TX 77079

Coral Power, L.L.C. (replaces Coral Power, Inc.)
ATTN: Joe Bob Perkins
2 Houston Center, 909 Fannin, Suite 700
Houston, TX 77010

CRSS Power Marketing
ATTN: Timothy Dunne, Pres. & Gen. Counsel
1177 West Loop South, Suite 900
Houston, TX 77027

D.C. Tie, Inc.
ATTN: c/o Peter Brickfield @ Brickfield & Kaufman
600 Watergate Building, Suite 915
Washington, DC 20037

Dartmouth Power Associates, L.P.
ATTN: Mitchell H. Jacobs, Esq., Treasurer
One Energy Road,
Dartmouth, MA 02747

Delhi Energy Services, Inc.
ATTN: Richard Meyer, Senior Attorney
1700 Pacific Avenue, LB-10
Dallas, TX 75201

Destec Power Services, Inc.
ATTN: W. Eric Dennison
2500 Citywest Blvd., Suite 150
Houston, TX 77210

Direct Access Management, LP
ATTN: L. Arthur Doty
RR Box 204,
Salisbury, VT 05769

Direct Electric, Inc.
ATTN: Alan Richards, VP Marketing
140 Beachway Avenue,
Palm City, FL 34990

Duke Energy Marketing Corporation (orig.:ER95-755)
ATTN: Albert V. Carr, Jr., Esq.
422 South Church Street, PB05E
Charlotte, NC 28242

Duke/Loius Dreyfus, L.L.C.
ATTN: Albert V. Carr, Jr., Esq.
422 South Church Street, PB05E
Charlotte, NC 28242

Duke/Louis Dreyfus Energy Services (New England)
ATTN: Ruby H. Melton. Esq.
10 Westport Road,
Wilton, CT 06897

E prime, inc.
ATTN: Davia L. Eves, General Manger
1331 17th Street, Suite 201
Denver, CO 80202

Eastern Power Distribution
ATTN: Mark L. Eisenhower, Senior VP
333 North Fairfax Street,
Alexandria, VA 22314

Eastex Power Marketing, Inc.
ATTN: Don B. Whaley, Vice President
1000 Louisiana, Suite 1100
Houston, TX 77002

Eclipse Energy, Inc.
ATTN: Lisa McElroy, President
333 N. Sam Houston Prkwy East, Suite 210
Houston, TX 77060

ElecTech, Inc.
ATTN: F. Thomas Hillegass
801 North Ninth Street,
Reading, PA 19604

Electrade Corporation
ATTN: Preston D. Head, Jr., President
200 Liberty Street, 23rd Floor, Tower A
New York, NY 10281

Electric Clearinghouse, Inc
ATTN: Molly H. Cook, Contract Admin
13430 Northwest Freeway, Suite 1200
Houston, TX 77040

Energy Alliance Partnership
ATTN: Holly Koeppel @ Consolidated Natural Gas Company
One Park Ridge Center,
Pittsburgh, PA 15244

Energy Marketing Services, Inc.
ATTN: Jeffrey A. Jones, President
355 East Campus View Blvd, Suite 150
Columbus, OH 43235

Energy Resource Management Corp.
ATTN: Ronnie James, President
615 Griswold, Ford Building, Suite 210
Detroit, MI 48226

Energy Resource Marketing, Inc.
ATTN: MaryJane Reynolds @ Morrison & Reynolds
1110 Vermont Avenue, NW, Suite 405
Washington, DC 20005

Energy Services Inc.
ATTN: Noel Shelton
101 E. 8th Street, Suite 240
Vancouver, WA 98660

Energy Transfer Group, Inc.
ATTN: Cliff Harris, President
8080 N. Central Expressway, Suite 650
Dallas, TX 75206

Energy West Power Company, LLC
ATTN: John Tomasello
5614 Stoneridge Drive, Suite 108
Pleasanton, CA 94588

Energyonline, Inc.
ATTN: Richard Albert
4962 El Camino Real, Suite 112
Los Altos, CA 94022

Enerserve, L.C.
ATTN: Jeffrey A. Milford
P.O. Box 54618,
Tulsa, OK 74155

Engelhard Power Marketing, Inc.
ATTN: Arthur A. Dornbusch, II, Esq.
101 Wood Avenue,
Iselin, NJ 08830

Enova Energy Management, Inc.
ATTN: James F. Walsh, III
P.O. Box 1831,
San Diego, CA 92112

Enpower, Inc.
ATTN: Daniel L. Smith, President
3803 Turkey Oak Drive,
Valrico, FL 33594

Enron Power Marketing
ATTN: Steve Kean, Asst. Gen. Counsel
P.O. Box 1188,
Houston, TX 77251

Ensearch Development Corporation (EDC)
ATTN: Peggy J. Banczak, Esq.
1817 Wood Street, Suite 550 West
Dallas, TX 75201

Entergy Power Marketing Corporation
ATTN: Frederick F. Nugent, Esq.
900 S. Shackleford Road, Suite 210
Little Rock, AR 72211

Equitable Resources Marketing Company
ATTN: Boyd L. Henderson, VP & Gen. Coun.
200 West Lake Park Blvd., Suite 900
Houston, TX 77079

FILE CONTINUED