BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3000124

Duquesne Light Company

Statement No. 9

DIRECT TESTIMONY OF ROBERT L. O'BRIEN

Dated: March 28, 2018

TABLE OF CONTENTS

Page

CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your full name and business address.

A. My name is Robert L. O'Brien, and my business address is 1753 Via Mazatlan, Rio Rico, Arizona 85648.

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

A. I am employed by O'Brien Innovative Regulatory Solutions, LLC where I am the Sole Member.

Q. Please summarize your professional experience and educational background.

A. I have been employed in my current position since January 4, 2008 after my retirement from Black & Veatch Corporation ("B&V) where I worked in the Executive Management Services division as a Principal Consultant. Prior to that, I was employed by R.J. Rudden Associates ("Rudden"), where I served as Vice President. In these positions, I have assisted clients in the areas of Strategic Planning, State Regulatory Operations, Financial Planning, Cash Working Capital Calculations, Rate Case Preparation, Revenue Requirement Determination and Revenue Requirement Model Design.

Prior to joining Rudden in 2000, I was employed by Citizens Communications Company (formerly Citizens Utilities Company) ("Citizens") from 1975 to 1999 holding the positions of Vice President, Strategic Planning and Regulatory Affairs for Citizens' Public Utilities Sector (1997 to 1999); Vice President, Corporate Regulatory Affairs (1978 to 1997); and Manager of Special Studies (1975 to 1978). From 1967 to 1975, I was employed as controller by a series of companies engaged in the financial, communications, educational and printing industries. Prior to 1967, I was employed by Ernst & Young where I attained the status of Senior Auditor after four years (including two-years work experience during a 5-year work-study program at the University of Cincinnati). I graduated from the University of Cincinnati in 1965 with a Bachelor of Business Administration, having majored in Accounting. I am a Certified Public Accountant.

Q. Have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory agencies?

A. Yes. I have testified or filed testimony before this Commission many times on behalf of Citizens' water and telephone operations; on behalf of Duquesne Light Company ("Duquesne Light" or the "Company") in its 2006, 2009 and 2013 applications for a general rate increase; on behalf of PECO Energy Company in a 2008 gas rate proceeding and again in the 2010 rate applications for its gas division and its electric division. In addition, I have presented testimony and or testified in over 250 proceedings before state regulatory commissions in Arizona, California, Colorado, Hawaii, Idaho, Illinois, Indiana, Missouri, Montana, Nevada, Ohio, Rhode Island, Tennessee, Vermont and West Virginia on behalf of electric, natural gas, communications, water and wastewater utility companies. Those proceedings involved company-initiated rate increases, commission-ordered rate reviews, purchased energy pass-through proceedings, acquisitions and sales of utility companies, disaster relief requirements and the recovery of acquisition premiums. I have testified concerning all measures of value elements, including deferred income taxes and cash working capital, as well as revenues, operating expenses, income taxes, rate design and rate of return issues. I have also testified in generic proceedings related to income taxes, as well as changes in the regulation of the communications and electric industries.

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

A. I was asked by Duquesne Light to assist it in preparing and presenting a request for a general rate increase for its Pennsylvania electric distribution delivery operations. More specifically, I develop the components of Duquesne Light's overall revenue requirement, and will support certain pro forma ratemaking adjustments for the fully projected future test year ended December 31, 2019 ("FPFTY"), the future test year ended December 31, 2018 ("FTY") and the historic test year ended December 31, 2017 ("HTY"), and portions of the claimed measures of value, including Duquesne Light's cash working capital allowance.

Q. Before discussing the specific adjustments and schedules you are sponsoring, please describe the relationship of your work to that of the other Company witnesses.

A. In general, my assignment was to prepare pro forma adjustments to each of the three test years to obtain total Company pro forma balances for each test year. The total Company values were developed and classified by use of the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts for Mr. Gorman to use in his Jurisdictional Separation Study ("JSS") which determines the pro forma earnings at present rates and the revenue increase required for the Company's Pennsylvania jurisdictional distribution assets and his related Cost of Service Study ("COSS"). As a starting point, I used the actual, budgeted and/or projected data for each year provided by Mr. Ankrum. In addition, I developed, working with Company personnel, pro forma adjustments based on total Company operations. Finally, I provided the total Company pro forma measures of value and operating revenues and expenses for the HTY, FTY and FPFTY to Mr. Gorman who, through a JSS for each test year, determined the allocated jurisdictional amounts correctly assigned to the Pennsylvania jurisdiction for the Company's distribution operations and also a COSS for the FPFTY.

Q. Are you sponsoring all or portions of any exhibits in this proceeding?

A. Yes. Together with other Company witnesses, I am sponsoring portions of DLC Exhibits 2, 3 and 4, which comprise Duquesne Light's principal accounting exhibits for the FPFTY, FTY and the HTY respectively. As explained by Mr. Ankrum (DLC St. No. 2), Duquesne Light's Controller, the base data for the FPFTY in DLC Exhibit 2 were derived, for the most part, from Duquesne Light's capital and operating forecasts for the twelve months ended December 31, 2019; the corresponding data for the FTY in DLC Exhibit 3 were taken from Duquesne Light's budgets, books and records for the year ended December 31, 2018 and finally the data for the HTY in DLC Exhibit 4 from the actual data for the year ended December 31, 2017. In addition, I am responsible for the responses provided to certain of the Commission's standard data filing requirements.

Q. Will you be discussing DLC Exhibit 2, DLC Exhibit 3 and DLC Exhibit 4?

A. Yes, I will. However, because Duquesne Light is basing its proposed rate increase on the adjusted FPFTY (December 31, 2019) data, I will focus my comments on Section C (Measures of Value/Rate Base) and Section D (Operating

Income/Revenues and Expenses) of DLC Exhibit 2. My testimony regarding DLC Exhibit 3, which is Duquesne Light's FTY (December 31, 2018) and DLC Exhibit 4 which is Duquesne Light's HTY (December 31, 2017) are organized in essentially the same format as DLC Exhibit 2, will briefly address the pro forma adjustments and any area that requires additional comment or information.

Q. How is the balance of your testimony structured?

A. In Section II, I present an overview of Duquesne Light's FPFTY revenue requirement and explain, in summary fashion, how the claimed measures of value, pro forma present rate revenues, operating expenses, depreciation and taxes were determined. Section III of my testimony provides a more detailed description of the individual components comprising Duquesne Light's requested measures of value for the FPFTY, while Section IV discusses the derivation, including appropriate ratemaking adjustments, of Duquesne Light's revenue and expense claims for the FPFTY. Finally, Section V contains the presentation of the FTY and the HTY data.

II. OVERVIEW OF DUQUESNE LIGHT'S FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

Q. Please explain how the Company's FPFTY December 31, 2019 measures of value were determined.

A. First, to determine FPFTY-end utility plant in service, the Company began with the closing plant balances at December 31, 2017, added the budgeted capital expenditures that are projected to close to plant in service during twelve months ended December 31, 2018, subtracted the appropriate plant retirements and made any reclassifications or adjustments which resulted in the plant in service balances at December 31, 2018. The same procedures were followed using plant closings through December 31, 2019 which resulted in the plant in service balances at December 31, 2019. The accumulated depreciation at December 31, 2019 was determined in a similar fashion, using the closing balances at December 31, 2017 plus the budgeted and or pro forma depreciation expense, amortization of net salvage and the plant retirements through December 31, 2018 and for the FPFTY. The accumulated deferred income taxes ("ADIT") credit includes an amount for the federal ADIT, net of an offset for the federal income tax previously paid by the Company on the receipt of contributions-in-aid-of-construction ("CIAC"). The claimed levels of materials and supplies, customer deposits and customer advances for construction are based on 13-month historic averages for the period ended December 31, 2017, and working capital was calculated using lead-lag study procedures. Each of these components and the other elements shown on DLC Exhibit 2, Schedule D-1, page 3 of 3, column 1, lines 1 to 13 of the measures of value will be described later in my testimony. This total Company data, as described by Mr. Gorman, are then allocated to the Pennsylvania Jurisdiction as shown in column 2.

Q. How were the revenues at present rates for the FPFTY derived?

A. Revenues at present rates were derived by adjusting the forecasted revenues for Duquesne Light's electric operations for the twelve months ending December 31, 2019 to reflect the removal of surcharge revenues; to reflect changes in data from the time the initial revenues were developed; to reflect the annualization of customers to year-end levels in the FPFTY and to reflect the other pro forma revenue adjustments as described in connection with those adjustments which are summarized in DLC Exhibit 2, Schedule D-5.

Q. How were the claimed operating expenses for the FPFTY determined?

A. The pro forma FPFTY expenses were calculated using Duquesne Light's forecast for the twelve months ended December 31, 2019 as a starting point. Those expenses, which were prepared based on business activities and related cost elements such as payroll, employee benefits, etc., were distributed to FERC accounts using the distribution actually experienced by the Company during the year ended December 31, 2016. Adjustments were then made to the forecast data including annualization and normalization adjustments in accordance with established Commission ratemaking practices. These adjustments are summarized on DLC Exhibit 2, Schedule D-3 pages 1 and 2 and are described in connection with the specific schedules included in DLC Exhibit 2. Each pro forma adjustment was then included in the appropriate FERC accounts.

Q. Please describe how the taxes-other-than-income ("TOTI") were determined for the FPFTY.

A. Those amounts were determined by using forecasted amounts for the twelve months ended December 31, 2019, with pro forma adjustments to payroll taxes to reflect the impact of the changes to FPFTY salaries and wages and other adjustments to reflect known and measurable changes, as shown on DLC Exhibit 2, Schedule D-16.

Q. Please describe the calculation of depreciation expense for the fully projected future test year.

A. The pro forma depreciation expense for the FPFTY was determined by FERC account using the average of plant in service balances at December 31, 2018 and December 31, 2019 times the depreciation rates determined by Mr. Spanos in his depreciation study as described in his testimony (DLC St. No. 10) or by using depreciation rates based on Company data for intangible, leasehold and transportation plant. This was then adjusted to reflect the use of the year-end plant at December 31, 2019. The five-year amortization of net salvage was added, by FERC account to determine the total depreciation and amortization expense for the FPFTY as described in more detail in connection with Schedule D-17 of Exhibit DLC 2.

Q. How were income taxes calculated?

A. Income taxes were calculated using the regulatory procedures normally followed by the Commission, including the use of synchronized interest expense; the flow-through of certain tax deductions for State income tax calculation; the normalization of the federal method difference for accelerated depreciation and other normalized deductions as explained by Mr. Simpson in his testimony (DLC St. No. 11). The income tax expense for the FPFTY for total Company operations at present rates and for the distribution operations at proposed revenue levels is shown on DLC Exhibit 2, Schedule D-18, page 1 of 3. The income tax expense, as explained by Mr. Simpson in DLC Statement No. 11, was calculated using the provisions and rates under the Tax Cuts and Jobs Act ("TCJA").

Q. Please describe how the pro forma revenue increase and revenues at proposed rates were established.

A. Each of the total Company forecasted amounts and pro forma adjustments, which will be described in testimony related to the specific filing schedule or requirement, were used to determine the total Company pro forma measures of value, revenues at present rates and expenses. These total Company amounts were provided to Mr. Gorman and used by Mr. Gorman as the basis for the JSS which determined the fully distributed costs and the revenue requirement for the Company's Pennsylvania distribution operations. The summary results for the Company's jurisdictional distribution operations are presented in DLC Exhibit 2, Schedule D-1 pages 1 to 3.

Q. What is the overall required increase in annual revenues for the Company's jurisdictional distribution operations for the FPFTY?

A. As shown on DLC Exhibit 2, Schedule D-1, page 1 of 3, column 2, line 2 and also on line 20 of DLC Exhibit 2, Schedule D-1, page 2 of 3, the proposed increase in annual operating revenues is $81.595 million. Mr. Gorman will testify regarding the calculations related to the distribution revenue increase, including a description of how several existing revenue surcharges were included in base rates.

Q. What is contained in DLC Exhibit 2, Schedule B?

A. Schedule B contains Schedules B-1 to B-8 which present the Company's financial data for the FPFTY are sponsored by Messrs. Ankrum, Simpson, Milligan and Moul as indicated on each schedule.

III. MEASURES OF VALUE

A. Plant In Service

Q. Please describe Schedule C-1 of DLC Exhibit 2.

A. Schedule C-1 summarizes the measures of value for the FPFTY for the total Company and the Pennsylvania jurisdiction, the pro forma returns at present rates for the total Company and the Pennsylvania jurisdiction and the pro forma return at proposed rates for the Pennsylvania jurisdiction. The data for the total Company are supported by me and the data for the Pennsylvania jurisdiction will be described and supported by Mr. Gorman. As shown on line 1, the total Measures of Value for the total Company is $2.558 billion (column 1, line 1) billion and is $1.926 billion (column 2, line 1) for the Pennsylvania jurisdiction. The net operating income and earned rate of return at present rates for the total Company and the Pennsylvania jurisdiction are shown on lines 2 and 3 in columns 1 and 2 respectively. Finally, the pro forma return at proposed rates for the Pennsylvania jurisdiction of $155.3 million (line 4), that is required to attain the target rate of return of 8.06%, shown on line 5.

Q. Please describe Schedule C-2 of DLC Exhibit 2.

A. Schedule C-2 contains 4 pages and presents the Company's claimed FPFTY utility plant in service.

Q. How was the utility plant in service of $4.558 billion shown on Schedule C-2, page 1, column 3, line 7 determined?

A. That amount represents the estimated plant in service balance at December 31, 2019 and is based on utility plant in service at December 31, 2017 plus budgeted and forecasted capital expenditures estimated to be closed to plant in the FTY and the FPFTY, less the FTY and FPFTY estimated retirements and pro forma adjustments to the FTY and FPFTY plant. The plant balances at December 31, 2019 by FERC account are shown on page 2 with the detail for plant additions, retirements and adjustments for the year ended December 31, 2019 shown on pages 3 and 4. The total plant in service of $4.558 billion is entered on DLC Exhibit 2, Schedule D-1, page 3 of 3 at column 1, line 1 for the total Company.

Q. Please describe what is contained on Schedule C-2, page 2.

A. Page 2, column 2, presents the year-end plant balances for the FPFTY by FERC account and summarized by functional plant category. The total plant in service at December 31, 2019 of $4.552 billion shown on line 41 in column 2 is brought forward by functional plant category to page 1, column 1, lines 1 to 4.

Q. What is shown on page 3 of Schedule C-2?

A. Page 3 shows the plant balances and activity by FERC account for the FPFTY. Column 2 contains the balances at December 31, 2018 while plant additions for the FPFTY are show in column 3. Plant retirements for the FPFTY are shown in column 4 and reclassifications and adjustments are shown in column 5. The FPFTY balance at December 31, 2019 of $4.552 billion is shown in column 6 on line 51 and is reflected on pages 1 and 2 of Schedule C-2.

Q. Please describe the amounts in column 5 for plant reclassifications.

A. Column 5 of page 3 contains the reclassification of plant additions related to the Company's Smart Meter program from separate line items (lines 48, 49 and 50) to inclusion into the appropriate plant accounts, 303, 370 and 397 respectively. This reclassification reflects the Company's decision to stop the Smart Meter surcharge (except for reconciliation requirements) and include the related FPFTY revenue, expense, plant, accumulated depreciation and other related elements in base rates. The plant additions through December 31, 2018 have been included in the appropriate accounts (303, 370 and 397) in column 2 as has the accumulated depreciation which will be described in connection with Schedule C-3, page 3. These reclassifications are required since the Company, as described by Mr. Ogden in his testimony (DLC St. No. 15), is rolling the Smart Meter surcharge revenue into base revenue and including recovery for the related net investment and expenses in establishing its base rates in this proceeding.

Q. Please describe the adjustments in column 5 on page 3.

A. The adjustments on lines 6 and 7 reflect a reclassification resulting from work by Mr. Spanos in his depreciation study which requires a change between plant accounts 352 and 353 in the recording of $830,000 of plant additions from what the Company included in its forecast. The adjustments on lines 40, 41, 44 and $1.820 million on line 43 ($871,000 of the amount on line 43 is from the Smart Meter reclassification) are the result of adjustments in plant retirements included in the Company's forecast as recommended by Mr. Spanos after completing his depreciation study. The Company has reflected these recommended changes in its presentation.

Q. What is contained on Exhibit DLC 2, Schedule C-2, page 4?

A. This schedule contains the pro forma adjustment to reflect capital expenditures for development of cloud-based information systems that were not included in the

Company's capital expenditure budgets but are required on a going forward basis. The support for this adjustment is provided by Mr. Ankrum in his testimony (DLC St. No. 2). The adjustment will be described in more detail in connection with Schedule D-11.

Q. What is the total plant in service pro forma for at the end of the FPFTY?

A. The total plant in service for the Company in the FPFTY is $4.558 billion as shown on Schedule C-2, page 1 of 4, column 3, line 7 and also on Exhibit 2, Schedule D-1, page 3, column 1, line 1.

B. Accumulated Depreciation

Q. What is the purpose of Schedule C-3 of DLC Exhibit 2?

A. This schedule, consisting of 4 pages, presents the accumulated provision for depreciation at December 31, 2019 by FERC account. Duquesne Light's accumulated depreciation at December 31, 2019 is $1.506 billion as summarized on page 1, column 4, line 7 of Schedule C-3 and then carried forward to page 3, column 1, line 2 of Schedule D-1.

Q. Please describe page 1 of DLC Exhibit 2, Schedule C-3.

A. This page shows the accumulated depreciation balance by FERC plant category at the end of the FPFTY. These balances include the accumulated depreciation at December 31, 2018 plus depreciation expense, amortization of average net salvage, less retirements, less cost of removal and adjustments which are reflected on DLC Exhibit 2, Schedule C-3, on page 3 in columns 3 to 10 by FERC account.

Q. What is contained on pages 2 to 4 of Schedule C-3?

A. Page 2 shows the pro forma accumulated depreciation for the FPFTY by FERC account. Page 3 contains eleven columns showing the changes to the FPFTY accumulated depreciation balances by FERC account from December 31, 2018 (column 2) to December 31, 2019 (column 11). Column 3 shows the depreciation expense for 2019 while column 4 shows the plant retirements. Columns 5 to 10 show other charges and credits to the accumulated depreciation for 2019. Page 4 shows the accumulated depreciation adjustment related to the adjustment to plant shown on DLC Exhibit C-2, page 4.

Q. What is the balance for accumulated depreciation at the end of the FPFTY?

A. That amount is $1.506 billion shown on DLC Exhibit 2, Schedule C-3, page 1, column 4, line 7 and also on DLC Exhibit 2, Schedule D-1, page 3, column 1, line 2.

C. Cash Working Capital

Q. What is set forth on Schedule C-4, page 1, of DLC Exhibit 2?

A. This is a summary of the Cash Working Capital ("CWC") calculations, which are detailed on pages 2 to 10 of this schedule. The total of $59,997 million shown on line 6 is included in Duquesne Light's claimed measures of value for the total Company, as shown on DLC Exhibit 2, Schedule D-1, page 3 of 3, column 1, line 4. The CWC amount for the PA Jurisdictional business is $38.621 million as shown in column 2.

Q. Please describe page 2 of Schedule C-4.

A. Page 2 summarizes the derivation of Duquesne Light's revenue collection lag and overall operating expense payment lag. The revenue lag days of 59.85 days is shown on line 1; the expense lag days for each of the expense components appear on lines 2 to 6 and totaled on line 7; and the composite O&M expense lag days of 27.76 days is shown on line 8. The net lag in the collection of revenue of 32.09

days (59.85 – 27.76) shown on line 9 is then multiplied by the average daily operating expense balance on line 10 to arrive at the base CWC amount of $19.862 million for operating expenses shown on line 11. The average daily operating expense balance of $619,000 on line 10 was determined by dividing the total pro forma annual operating expenses of $226.095 million on line 7, column 2, which excludes uncollectible accounts expense and purchased power costs, by the number of days in a year, 365. The other components of CWC are shown on lines 12 to 14 and will be described in connection with my discussion of related supporting schedules. The calculation of the working capital for power purchased shown on lines 16 to 19 is shown separately so it can be assigned directly to the purchased power activity by Mr. Gorman and not included in the determination of working capital for the PA jurisdictional operations.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The total revenue lag days shown on line 21 of 59.85 days were determined by dividing the average month-end accounts receivable balances for the thirteen months ended December 31, 2017 shown in column 2 on line 17 into the annual revenue billed during the 12 months ended December 31, 2017, as shown in column 3 on line 17. This results in an accounts receivable turnover rate of 8.56 (column 4, line 17), which is equivalent to 42.64 lag days (365 days divided by the 8.56 accounts receivable turnover rate), as shown in column 5 on line 17. This is referred to as the collection lag or the payment portion of the revenue lag. The payment portion of the revenue lag is added to (1) the 2.0-day lag between the meter reading day and the day bills are recorded as revenue and accounts receivable by the Company and (2) the 15.21 day service period lag, which is the time from the mid-point of the service period until the meter reading date, generating a total revenue lag of 59.85 days, as shown on line 21.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the days in an average month (365 days divided by 12, or 30.42 days) divided by 2, or 15.21 days.

Q. What is shown on page 4?

A. Page 4 shows the monthly revenue by class of service for the years ended December 31, 2015 through 2017.

Q. Please describe page 5 of Schedule C-4.

A. Schedule C-4, page 5, shows the calculation of the expense lags for specific expense categories used in the CWC calculation as shown on Schedule C-4, page 2, column 3, lines 3 to 6. Lines 1 to 5 reflect the payroll expense lag. The payroll amounts reflect the forecasted payroll amounts for the FPFTY as shown on Schedule D-7. The lag periods for the payment of union and non-union payroll are shown separately to reflect Duquesne Light's actual payment cycles for each classification. Lines 6 and 7 show the lag in the payment of pension costs for the FPFTY. The lag period is calculated using a mid-point of July 1 and the payment date shown on line 6 in column 1. This results in an average payment lead of 124.0 days, which was applied to the pro forma pension expense from Schedule D-9, page 1, line 11 and shown on line 4 of Schedule C-4, page 2 of 10.

Q. How did you develop the lag days associated with the purchased energy costs shown on line 13 of Schedule C-4, page 5?

A. Effective June 1, 2013, Duquesne Light began to purchase power for its default-service customers through a Supply Master Agreement. The payment terms under this contract result in a lag-day component of 33.88 days which is used for the purchased energy lag-days. This includes a service period lag of 15.21 days; a bill processing lag of 8.67 days and a payment lag of 10 days. The 33.88 payment lag days results in a net lead of 26.32 days when subtracted from the revenue lag days of 59.80 calculated on DLC Exhibit C-4, page 3 and shown on line 21. The 26.32 payment lead days is used to calculate the cash working capital requirement related to the purchased energy of $14.452 million shown on DLC Exhibit C-4, page 2 on lines 16 to 19. These amounts have been removed from the operating expenses summarized on lines 3 to 7 and are shown separately so they can be removed by Mr. Gorman from the PA Jurisdictional CWC calculation. As shown on Mr. Gorman's JSS, this amount is assigned directly to the Supply sector and is not included in his determination of the PA Jurisdictional distribution revenue requirement.

Q. Please describe how you determined the payment lag associated with other operating and maintenance expenses shown on line 6 of page 2.

A. The summary of the average payment lag for all remaining expenses listed as other expenses on line 6, is set forth on lines 14 to 18 of page 5 of Schedule C-4. These amounts were derived from data for the four months shown on page 6 of Schedule C-4. More specifically, I requested that the Company provide a listing of all cash disbursements during each of the four months selected in a format that would show the payee, the date the service was provided or the invoice date, the amount of the disbursement, the type of payment, the date the payment cleared the bank, the account to which the disbursement was charged and certain other data. Each month's listing contained thousands of cash disbursements.

Q. How did you utilize the data provided by the Company?

A. I used the total data provided by the Company for each month, calculated the number of days it took each disbursement to clear the bank from the invoice or service date and calculated the dollar days (the amount of the actual disbursement times the number of days the payment took to clear the bank) and sorted the disbursements by amount. I then eliminated disbursements that should not be included in a CWC calculation.

Q. What disbursements did you eliminate from the balances used on page 6 of Schedule C-4?

A. First, using the data for February 2017 as an example, referring to line 1 of page 6, I started with a total number of cash disbursements (exclusive of expenditures recorded "below-the-line" which are not charged to utility operations) of 2,598 (column 1) and a total dollar amount of those disbursements of $100.549 million (column 2) which produced a total dollar days of $1.536 billion (column 3). This resulted in expense payment lag days of 15.28 days (column 4). I then removed all disbursements under $1,000 since those amounts, while significant in number, would not have a meaningful impact on the overall lag-day calculation. Next, I removed all disbursements charged to asset and liability accounts, except charges to accounts payable. The results of these two removals provided the balances on line 2 which provided a base number of lag days for the other disbursements. While the number of disbursements dropped significantly from 2,598 to 469 and the dollar amounts also decreased significantly as show in columns 2 and 3 on lines 1 and 2, there was no significant movement in the expense lag-days as shown in column 4. In the next steps I removed disbursements for accounts payable, remaining negative amounts in two of the months and also all disbursements in excess of $350,000 since they are not likely to represent normal monthly operating expenses. The final result for February 2017, shown on line 3, is 42.44 lag-days. A similar process was followed for the months of May, August and November 2017 with the lag-days for each month shown on lines 6, 9 and 12 in column 4. The totals for the four months are included on lines 13 to 15 which result in 41.69 expense lag-days for other disbursements as shown on line 15, column 4. These data are summarized on page 5, lines 14 to 18 and the average of 41.69 lag-days is reflected on page 2 of 11, column 3, line 6.

Q. Please explain how the average prepayments of $8.978 million included on line 12 of Schedule C-4, page 2 were determined.

A. That amount is calculated on page 10 of Schedule C-4 and represents the thirteen-month average of actual amounts for each month end from December 2016 to December 2107. As shown on page 10, the prepayments in question comprise 24 different items, ranging from commission assessments to insurance.

Q. **How did you determine the lag days for the tax expense component of working capital shown on page 7 of Schedule C-4 and brought forward to page 2 on line 13?**

A. The calculations on page 7 of Schedule C-4 use the pro forma tax expense at proposed rates shown in column 1 and the net revenue lag days for each tax as shown in column 4. The result of the multiplication of those components is shown in column 3 and used as the working capital related to the taxes paid by the Company. The net payment lag days for each of the taxes are calculated on page 9 of Schedule C-4.

Q. **Please describe the calculation of the interest expense lag shown on page 8 and included on page 2, line 14 of Schedule C-4.**

A. This calculation measures the lag associated with the semi-annual payment of interest on outstanding debt. The pro forma interest expense is the amount resulting from the synchronized interest calculation using the pro forma measures of value and the weighted cost of debt included in the requested rate of return. The daily interest expense amount of $147,000, calculated on line 5, is multiplied by the net payment lag of 31.40 shown on line 8 for a reduction to the working capital allowance of $4.605 million, as shown on line 9 and included on page 2 at line 14.

Q. **What is presented on page 9 of Schedule C-4?**

A. As noted previously, this page provides the calculations of the net payment lag days for the tax expense components of Duquesne Light's CWC allowance. The type of tax and the payment schedule for that tax are shown in the description column with the actual payment dates reflected in column 1. The payment lead or (lag) from the midpoint of the year is shown in column 3. The pro forma payment amount for each tax is shown in column 4 on the line with the name of the tax. For example, the federal income tax amount, pro forma at proposed revenue levels for the total Company, of $32.618 million is shown on line 1 in column 4. The payment amounts required are reflected for each tax on the dates shown in column 1 and the weighted lead (lag) for each payment is calculated in column 5 for each tax. The payment lead (lag) days are calculated and shown on the total line for each tax. These days are compared to the lag days for revenue shown in column 7 and the net payment lag is shown in column 8 and also reflected on page 7 of Schedule C-4.

Q. Why are separate calculations made for the various categories of tax expense?

A. This is necessary because each of the tax expense items has separate payment dates. For example, as shown on page 9 of Schedule C-4, 25 percent of the estimated federal income tax liability is due on April 15, June 15, September 15 and December 15 of each year. The tax payment dates and percentages due for other tax expense items are not the same. Using a separate calculation for each tax expense provides a matching of the cash requirement for payment of those expenses with the anticipated cash from revenues.

Q. What is shown on Schedule C-4, page 10?

A. This page shows the calculation of the average prepaid expenses included in the CWC which was described earlier in my testimony.

Q. What is the total amount of CWC included in the claimed measures of value?

A. That amount is the $59.997 million shown on Schedule C-4, page 1, line 6 and on Schedule D-1, page 3 of 3, column 1, line 4.

D. Materials and Supplies

Q. Please describe Schedule C-5.

A. Schedule C-5 reflects the Materials and Supplies for the FPFTY based on the thirteen-month average from December 31, 2016 to December 31, 2017 of $23.523 million as shown on line 16. The distribution of the average to various functions is shown on lines 17 to 22.

E. Accumulated Deferred Income Taxes

Q. What is the purpose of Schedule C-6?

A. Schedule C-6 shows the December 31, 2019 balance of accumulated deferred income taxes ("ADIT") that is deducted in the determination of the measures of value. The ADIT shown on line 6 of $669.799 million reflects the federal income tax that must be deferred in compliance with the normalization provisions concerning the use of accelerated tax depreciation on FPFTY plant balances. The ADIT balance also reflects the normalization of the tax repair deductions and Section 263A deductions as permitted by the Commission. The accelerated tax depreciation and other tax deductions used in the determination of taxable income for federal and state income tax expense calculations are reflected on Schedule D-18, pages 1 and 2 of 3. These amounts are supported in the testimony of Mr. Simpson

Q. What is the amount of ADIT used in the measures of value?

A. The amount for the total Company is $669.799 million as shown on line 6 of Schedule C-6 and on line 11 of page 3 of 3 of Schedule D-1 in column 1.

F. Customer Deposits

Q. Please explain the data concerning customer deposits on Schedule C-7 that was deducted from the claimed measures of value on Schedule D-1, page 3.

A. The amount for customer deposits shown in column 1 reflects the average month-end balance for the thirteen months ended December 31, 2017. The amount for the interest expense paid to customers on the customer deposits is shown in column 2. The customer deposit amount is reflected as a reduction to the measures of value and the interest expense is shown as an operating expense for the FPFTY.

Q. Where are these amounts of customer deposits and interest shown?

A. The amount of customer deposits for the total Company is a deduction of $10.824 million, as shown on line 15 of Schedule C-7 and on Schedule D-1, page 3 of 3, line 9, column 1. In addition, the calculated interest expense related to these customer deposits of $290,000 is included in the Company's operating expenses as shown on DLC Exhibit 2, Schedule D-3, page 2 of 2, column 18, line 55.

G. Capitalized Pension Adjustment

Q. Please describe DLC Exhibit 2, Schedule C-8.

A. This schedule shows the calculation of the capitalized pension adjustment which, based on the Commission's acceptance of a settlement provision in the Company's 2013 rate case, Docket No. R-2013-2372129, the Company can include in its measures of value. The amount to be included in as a rate base adjustment is, "...the amount necessary to adjust the SFAS 87 capitalized pension amounts to equal accumulated capitalized pension contributions, net of applicable deferred income taxes, from January 2007 forward." (Settlement in Docket No. R-2013-2372129). Following the conditions of the settlement, the schedule shows the capitalized pension contributions in column 1 and the amount of the ASC 715 pension capitalized in column 2. The difference in column 3, $105.839 million, is the amount for the capitalized pension adjustment included in the measures of value for the FPFTY.

Q. What is the adjustment to include the capitalized pension adjustment in rate base for the FPFTY?

A. As shown on DLC Exhibit 2, Schedule 8, column 3, line 15, the amount is $105.839 million. This amount is also shown on DLC Exhibit 2, Schedule D-1, page 3 of 3, column 1, line 6.

H. Customer Advances for Construction

Q. How was the FPFTY amount for Customer Advances for Construction ("CAC") determined?

A. The CAC for the FPFTY was determined using the 13-month average for the months ended December 31, 2016 to December 31, 2017 as shown on DLC Exhibit 2, Schedule C-9.

Q. What is the CAC amount included in the Measures of Value for the FPFTY?

A. The amount is a deduction to measures of value of $1.839 million as shown on line 10 in column 1 of Schedule D-1, page 3 of 3. This is the same amount deducted from the Total PA Jurisdiction as shown in column 2.

Q. What is the Company's claimed measures of value in this proceeding?

A. Duquesne Light's claimed measures of value, or rate base, for the FPFTY equals $2.558 billion, as shown on line 13, page 3 of 3, column 1 of Schedule D-1 for the total Company and $1.926 billion for the Pennsylvania jurisdictional measures of value shown on Schedule D-1, page 3 of 3, column 2, line 13, which will be supported by Mr. Gorman.

IV. REVENUES AND EXPENSES

Q. What is shown on Schedule D-1 of DLC Exhibit 2?

A. Schedule D-1, which is supported by myself and Mr. Gorman, contains three pages showing the calculation of the total Company and Pennsylvania jurisdictional measures of value (rate base) on page 3, the total Company and Pennsylvania jurisdictional revenue, expense and operating income on page 2 and the Pennsylvania jurisdictional revenue requirement including the measures of value, revenues and expenses at present rates, the revenue increase required and the revenues and expenses at proposed rates. The Pennsylvania jurisdictional revenue increase that is calculated by Mr. Gorman is $81.595 as shown on page 2, line 20 and brought forward to page 1, column 2, line 2.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the revenues and expenses by major FERC account classification. It begins with the Company's forecasted revenues and expenses for the FPFTY in column 1, and then annualizes and/or normalizes those amounts through adjustments summarized in column 2. The pro forma data in column 3 are summarized and brought forward to Schedule D-1, page 2, column 1 and used in the determination of the required revenue increase. The various revenue adjustments in column 2 are shown on Schedule D-3 and listed by adjustment on Schedule D-5, and the expense adjustments are summarized on Schedule D-3 and described in more detail on the separate adjustment schedules beginning with Schedule D-6 through Schedule D-11.

Q. Please describe Schedule D-3.

A. Schedule D-3 summarizes the various adjustments that were made to the forecast revenue and expense data to derive the pro forma present rate revenues that appear in column 3 of Schedule D-2 and are included in the adjusted amounts that are carried forward to Schedule D-1. The FPFTY forecasted amounts are shown in column 1 on page 1 and the revenue adjustments are shown in columns 2 to 6 on page 1. The various expense adjustments are reflected in columns 7 to 10 of page 1 and in columns 13 to 18 of page 2 of Schedule D-3. Each of the pro forma adjustments will be described in connection with the specific schedule supporting the adjustment.

A. Revenue Adjustments

Q. Please describe Schedule D-5.

A. Schedule D-5 presents a summary of the separate pro forma adjustments to revenue for the FPFTY. Each of these adjustments will be described in detail in connection with the separate calculation of the adjustment shown on Schedules D-5A to D-5C.

Q. Please describe the adjustment calculated on Schedule D-5A, which is shown on Schedule D-5 in column 3.

A. This adjustment removes revenue recovered through surcharges as shown on lines 1 to 9 and summarized on lines 33 to 36. Related costs and expenses are also removed from other sections of the presentation for the FPFTY. The forecasted revenue amounts are shown in columns 2 and 3 with the related gross receipts tax amounts in column 4 and the net amounts in column 5. The total adjustment to revenue of $26.439 million on line 33 is shown on Schedule D-5, column 3, line 1. In addition, the schedule shows the total amounts for four surcharges that are being included in base rates in the FPFTY. These are the Smart Meter, DSIC, Retail Market Enhancement and State Tax Adjustment surcharges in the amounts shown in columns 1 and 2 on lines 10 to 31 and totaled on line 32 in the amount of $52.161 million. The revenue from these four surcharges is being included as part of the Company's revenue at present rates and is not part of the requested revenue increase. This is confirmed by the revenue data on Schedule D-5, line 2. The total surcharge revenue at present rates shown on Schedule D-5, column 1, line 2 is $78.600 million. Once the surcharge revenue of $26.439 million shown in column 3 on line 2 is removed, the remaining $52.161 shown in column 9, line 2 of Schedule D-5 is included as pro forma adjusted at present rates. Mr. Ogden describes how these surcharge revenues are included in the base rates for the FPFTY in his testimony (DLC St. No. 15).

Q. What is the adjustment on Schedule D-5B which is included on Schedule D-5 in column 4?

A. This adjustment shows the calculation of revenue lost from energy efficiency and conservation activities of the Company and its customers for the years 2020 to 2022 and the average for those years which is included as an adjustment to the FPFTY.

Q. Please describe the calculations on Schedule D-5B.

A. Schedule D-5B contains variable revenue levels for 2019 to 2022 by customer category on lines 1 to 5. Lines 6 to 20 show the revenue reductions for each year 2020 to 2022 (columns 3, 4 and 5 respectively) compared to the revenue included in the FPFTY base data in column 2. The total difference for each year is shown in column 6 on lines 10, 15 and 20 respectively. Line 21 shows the total lost revenue and line 23 has the average for the three years.

Q. Have you determined these lost revenue amounts?

A. The revenue loss amounts I am presenting were based on forecasts by Mr. Mobley in his testimony (DLC St. No. 3) and calculations made by Mr. Ogden in his testimony (DLC St. No. 15).

Q. Why should this adjustment be included in this proceeding?

A. This adjustment reflects the reductions in revenue that the Company expects to experience related to the reductions in load required to meet the provisions of Act 129 of 2008 and other efficiencies in customer usage that the Company has been experiencing and will continue to experience through the period the rates set in this proceeding will be in effect. The Company must be able to recover these lost revenues during the period base rates set in the FPFTY are in effect or the Company will not have the opportunity to earn the rate of return authorized in this proceeding. For example, while the revenues projected for 2019, the FPFTY, reflect these lost revenues for 2019, the additional lost revenues that will occur in 2020, 2021 and 2022 will reduce the Company's revenue and earnings levels. Including the average lost revenue amounts determined by Mr. Mobley and Mr. Ogden for those years will provide the Company the opportunity to offset those lost revenues.

Q. What is the adjustment you are proposing for the average lost revenue?

A. The adjustment is the average for the 3-year period of $8.179 million as shown on Schedule D-5B in column 6 on line 23.

Q. Please describe adjustment D-5C.

A. This adjustment annualizes revenues for the projected number of customers at the end of the FPFTY compared to the average number of customers for the FPFTY. Line 1 shows the distribution and generation revenue for each customer classification for the FPFTY. These total revenues are reduced by the commodity revenues on line 2 and the resulting non-commodity revenues are shown on line 3. These non-commodity revenues are divided by the average number of customers for the test year on line 4 to determine the average non-commodity revenue per customer on line 5. The average non-commodity revenue, or margin on line 5 was then multiplied by the difference between the average number of customers (line 4) and the number of customers at the end of the FPFTY (line 6) which difference is shown on line 7, yielding the revenue annualization adjustment shown on line 8. For example, the average margin revenue per customer for the residential customer in column 1 on line 5 of $556 per year was multiplied by the increase in the number of customers of 1,172 on line 7 for an annualization adjustment for residential customers of $652,000 as shown on line 8. The total annualization adjustment of $542,000 for all customer classes is shown on column 5, line 8 and also in column 6 on Schedule D-5C.

B. Operating Expense Adjustments

Q. Does the Company budget its operating expenses by FERC account?

A. No, as mentioned previously, it does not. Rather, the Company budgets its operating expenses by cost element or business activity, such as payroll, employee benefits, rent, etc.

Q. How were the FPFTY data restated by FERC account for purposes of preparing this rate application?

A. The recorded FERC balances for the 12 months ended December 31, 2016 were analyzed to develop a chart showing charges for each cost element within each FERC account. After this process was completed, I then distributed the forecasted FPFTY charges by cost elements to the FERC accounts using the ratios experienced in 2016. For example, I determined how much of the payroll cost center expense in 2016 was charged to each FERC account in 2016 and then distributed the FPFTY forecasted payroll to FERC accounts based on those ratios. This process was used for each cost element category to transform the FPFTY expense by cost element forecast to a FERC account-based forecast.

Q. Why was it necessary to transform the FPFTY cost category forecast to a FERC-account based forecast?

A. Essentially for two basic reasons. First, the Company's annual reports to the Commission are presented on a FERC-account basis and having the FPFTY forecast presented in the same format facilitates a comparison of the FPFTY forecast data to prior years' experience. Second, it was necessary to have the FPFTY data available by FERC account for use by Mr. Gorman in his Jurisdictional Separation Study and also for use in his Cost of Service Study.

Q. Is this the same procedure you used in the last rate case for the Company?

A. Yes. Consistent with the procedures used in the last rate case, I removed the expenses that are recovered through surcharges and those expenses that are charged below-the-line from the Cost Elements before they were distributed to the FERC accounts. This process clearly shows that expenses recovered through surcharges and also those that are charged below-the-line are not included in the Company's revenue requirement in this application.

Q. Have you prepared a schedule showing the total expenses by Cost Element for the FPFTY and the removal of the expenses recovered through surcharges as well as the expenses that are charged below-the-line?

A. Yes, I have. Exhibit RLO-1 to my testimony shows expenses by Cost Element for the years 2015 through the FPFTY. The total expenses for the FPFTY are shown in column 5 in the amount of $260.181 million on line 49. From this total amount, the expenses recovered by surcharge (column 6) in the amount of $23.533 million; the expenses charged below-the-line (column 7) in the amount of

$2.727 million are removed leaving a net expense for the FPFTY of 233.901 million as shown on line 49 in column 8. The amount of each Cost Element distributed to FERC accounts and therefore included in the FPFTY expenses is the amount in column 8, after the removal of the expenses recovered through surcharges and the expenses charged below-the-line. A similar procedure was used for the FTY and HTY as reflected on Exhibits RLO-2 and RLO-3 to my testimony which will be described later in my testimony.

Q. In your opinion, does this process result in a fair presentation of the Company's FPFTY forecast expenses by FERC account?

A. Yes, it does.

Q. Were each of the pro forma adjustments reflected on Schedule D-3 also charged to the appropriate FERC accounts?

A. Yes, they were.

Q. Are the various pro forma expense adjustments presented on Schedule D-3 shown by the type of expense and also by the FERC account distribution?

A. Yes, they are. The expense categories are identified in the headers of the columns on pages 1 and 2 of Schedule D-3 and each adjustment is described in connection with a separate schedule showing its derivation. These adjustments are shown by FERC expense category on Schedule D-3 and also on the Section D summary schedules.

Q. What is contained on Schedule D-6A, page 1 of 2?

A. Schedule D-6A contains adjustments to remove the expenses, by cost element, related to each of the revenue surcharges removed in adjustment D-5A discussed earlier. The major differences in the amounts for each surcharge reflect the fact that the revenue amounts include gross receipts taxes which are removed in the taxes other than income adjustment. There are also some minor differences resulting from true-up recording periods. The surcharge expense amounts are shown by CE on lines 1 to 13 and by FERC account on lines 14 to 19. The total of $23.598 million is shown on Schedule D-5A, line 37.

Q. **Do these expenses include expenses related to the surcharges that are being rolled-into the base rates in Duquesne Light's application?**

A. No. Those expenses are included in the FPFTY operating expenses and are not removed from the cost elements as the remaining surcharge related expenses are in this schedule.

Q. **Please describe the adjustment contained on Schedule D-6 A, page 2 of 2.**

A. This adjustment shows the supply expense and related gross receipts taxes that are removed from the establishment of the FPFTY base rate revenue requirement. The forecast is included in column 3 and in column 4, since there is no adjustment for lines 1 and 2 the amounts are the same. The adjustment shown on lines 4 to 6 reflects the removal of a cash working capital allowance included in billed revenue but not part of external payments for commodity sold. After adding the costs for sales for resale on line 8, the total cost is shown in column 4 on line 9 and brought forward to Schedule D-3, page 1 in column 7 on line 19. The adjustment to reflect the total cost of $200.405 in column 4 on line 9 of this schedule is shown on line 10.

Q. Please describe Schedule D-7.

A. Schedule D-7 consists of two pages and shows the calculation of the FPFTY annualization adjustments for salaries and wages ("S&W"). Page 1, column 2 contains the FPFTY forecast data summarized by FERC account categories showing a total to be expensed of $78.181 million on line 16, columns 2 and 4. Column 5 shows the annualization adjustment of $1.780 million distributed to the FERC expense categories, while column 6 lists the pro forma amounts for salaries and wages expense, totaling $79.961 million as shown on line 16 and an annualization adjustment to increase S&W of 2.277 percent as shown on line 17. The adjustment of $1.780 million in column 3 on line 16 is reflected on Schedule D-3, column 4 on lines 19 through 24.

Q. How was the annualization adjustment derived?

A. The calculation is shown on page 2 of Schedule D-7. In short, the adjustment annualizes forecast S&W expense to reflect the number of employees at the end of the FPFTY and certain pay rate increases to become effective during the FPFTY. More specifically, I have annualized a union pay rate increase forecasted to be effective on October 31, 2019 (lines 4 to 6 in column 2) based upon historic pay increases and the increase for non-union employees which will be effective on January 1, 2020 (lines 4 to 6 in column 3). As shown on line 6, each of these adjustments reflects the portion of these S&W increases that was not included in the FPFTY forecast. These adjustments seek to capture the S&W expense that Duquesne Light will incur at the end of the FPFTY.

Q. Please explain the calculations on lines 12 to 18 of Schedule D-7, page 2.

A. These calculations would normally provide an annualization for an increase in the number of employees during the FPFTY. However, since the FPFTY forecast included most of the new hires for the FPFTY at the beginning of the FPFTY, they are already included in the budget for a full year and therefore the annualization adjustment for new hires in the FPFTY is zero as shown on line 18.

Q. What is the total pro forma adjustment for S&W for the FPFTY?

A. The amount is $1.780 million, which is an adjustment of 2.277 percent as shown on lines 21 and 22 respectively.

Q. Please describe Schedule D-8 of DLC Exhibit 2.

A. Schedule D-8 shows the adjustment to normalize rate case expense. The Company incurred approximately $282,000 on this filing through December 31, 2017 (line 3) and has estimated an additional $1.690 million to complete the case. This total, $1.972 million (line 6) is normalized over a period of 3.0 years as shown on lines 7 and 8, which results in a total estimated normalized cost per year for this case of $657,000 as shown on line 8. This results in a reduction of $143,000 from the $800,000 forecasted expense as shown on lines 10 and 9 respectively.

Q. Why are you using a 3-year period for the normalization of the rate case expenses related to this proceeding?

A. As of now, the Company plans to file its next rate increase application before April 2021 using a FPFTY ended December 31, 2022. This will be three years after new rates in this proceeding are expected to be effective. The normalization period of 3 years reflects this period

Q. Please describe Schedule D-9 of DLC Exhibit 2.

A. Schedule D-9 reflects the calculation of the pension cost adjustment for the FPFTY. The adjustment reflects a three-year average of the expense component of contributions that the Company will make to its pension funds during the three years ending December 31, 2019, December 31, 2020 and December 31, 2021, which are supported by the testimony of Mr. Ankrum. The total for these three years is $30.0 million as shown on line 4 which results in a pro forma FPFTY amount for the pension contribution of $10.0 million as shown on line 6. Since a portion of these pension costs are capitalized, the Company has reduced this average contribution amount by 50 percent to reflect the portion of the pension contribution that will be expensed. The amount to be expensed in the FPFTY, $5.0 million, is shown on line 9. The $5.0 million on line 11 is the amount included in the Company's FPFTY forecasted expenses which results in an adjustment of $0.0 million as shown on line 13 and therefore no adjustment to the forecast pension expense is included on Schedule D-3, page 1, column 10, line 26.

Q. What is presented on Schedule D-10 of DLC Exhibit 2?

A. Schedule D-10 calculates an adjustment to the Company's forecasted uncollectible expenses. Lines 1 to 6 develop a five-year average rate of net uncollectible accounts charged off to total tariff revenue for the 2013-2017 period, which is then used in determining the level of uncollectible expense at pro forma proposed rates, as shown in the reference column on line 22 of Schedule D-2. It is also used to adjust the amount of uncollectible expense in the forecast for the FPFTY to conform to the five-year average for the charge offs. The resulting 1.250 percent shown on line 6 in column 5 of Schedule D-10 is used on line 8 with the pro forma revenues at present rates for the FPFTY shown on line 7 to calculate the pro forma uncollectible expense of $10.471 million shown in column 5 on line 9.

Q. What is the total uncollectible expense for the FPFTY proposed by the Company?

A. The total pro forma amount for uncollectible expense at present rates for the FPFTY is $10.471 million which is a net increase of $1.826 from the forecast as shown on line 11 and brought forward to Schedule D-3 in column 13 on line 55 on page 2. In addition, the 1.250 percent rate is used to provide for uncollectible expenses associated with the required revenue increase as shown on Schedule D-2, line 1.250 in the reference column.

Q. Please describe the adjustment contained on Schedule D-11.

A. This adjustment reflects the capitalization for development of cloud-based information systems required by Duquesne Light as described in the testimony of Mr. Ankrum (DLC St. No. 2). The implementation costs associated with these cloud-based information systems are budgeted as operating expenses as incurred in accordance with applicable accounting guidance. Column 1 shows expenditures during the years 2016 to 2019 while column 2 shows the year when the projects from those expenditures were or are to be completed and placed in service. Column 3 reflects the total plant while column 4 shows the depreciation expense and column 5 the accumulated depreciation at the end of each year. Finally, column 6 shows the net plant at the end of the FPFTY.

Q. What are the specific adjustments related to the investment in these systems?

A. First, the Company is adding $5.177 million to plant in service (column 2, line 7) which is shown on DLC Exhibit 2, Schedule C-2, page 1, column 2, line 1. Second, the Company is adding $1.325 million to accumulated depreciation (column 5, line 7) which is shown on DLC Exhibit 2, Schedule C-3, page 1, column 3, line 1. Third, $1.041 million of expenditures that were included in the Company's 2019 forecast FPFTY expenses is being removed (column 1, line 6) as shown on DLC Exhibit 2, Schedule D-3, page 2, column 14, line 58. Finally, $1.035 million is added to depreciation expense (column 4, line 10) as shown on DLC Exhibit 2, Schedule D-3, page 2, column 14, line 59.

C. Taxes – Other Than Income Taxes

Q. Please describe Schedule D-16 of DLC Exhibit 2.

A. Schedule D-16 contains 2 pages. Page 1 presents a summary of the forecast amounts for the FPFTY (column 3), adjustments to those amounts in column 4, and the pro forma expense amounts in column 5. The calculations for the payroll related changes are made on Schedule D-16, page 2 while the changes in the gross receipts tax ("GRT") are shown on page 1, lines 11 to 18. The calculations for the increase in payroll taxes, as shown on page 2, lines 1 to 4 for FICA expense, use the ratio of tax expense to payroll expense included in the FPFTY forecast times the payroll adjustment for the FPFTY to produce an adjustment to FICA expense for the FPFTY of $206,000 as shown on line 4. The same procedures were followed for the other related payroll tax items. The total pro forma increase of

$235,000 shown on page 2, column 5, line 14. These amounts are then reflected on page 1 in column 4. The adjustment to decrease GRT in column 4 on line 7 of page 1 in the amount of $2,070 million calculated on page 1, lines 11 to 18. The total adjustment is a net decrease of $1.835 million in pro forma FTY expense for taxes other than income shown in column 4 on line 10. The pro forma taxes other than income expense is $53.277 million as shown on Schedule D-16, page 1, line 10, column 5.

Q. Do you make an adjustment to recognize the additional GRT that will be required to be paid by the Company on the revenue increase allowed by the Commission in this proceeding?

A. Yes. As will be described in connection with DLC Exhibit 2, Schedule D-18, page 3, the incremental GRT is recovered through the gross revenue conversion factor ("GRCF") used to determine the amount of revenue required to provide the net income increase found reasonable in this proceeding.

D. Depreciation Expense

Q. Please describe DLC Exhibit 2, Schedule D-17, pages 1 to 3.

A. Schedule D-17 contains the depreciation expense for the FPFTY on page 1, the amortization of the cost of removal on page 2 and the total of the two elements is contained on page 3. The depreciation expense for the year was calculated on Schedule D-17, page 1, column 6 using the average of plant balances at December 31, 2018 (column 3) and December 31, 2019 (column 4) times the depreciation rates shown in column 2). The pro forma annualized depreciation expense shown in column 7 was calculated using the same depreciation rates in column 2 times the year-end December 31, 2019 plant balance.

Q. How were the depreciation rates in column 2 determined?

A. All of the rates, except the rates on lines 3, 14, 15, 35, 38 and 42 were determined by Mr. Spanos and supported in his testimony (DLC St. No. 10). The other rates, mainly for intangible, leasehold and transportation plant, were determined using Company data for the FPFTY.

Q. What is the amount of depreciation expense included in the Company's expense claim for the FPFTY?

A. The amount is $170.681 million as shown on DLC Exhibit 2, Schedule D-17, column 7, line 51.

Q. Please describe the calculation of the average net salvage amortization shown on page 2 of DLC Exhibit 2, Schedule D-17.

A. This schedule shows the 5-year average for the net salvage that is included as an amortization expense and also as an addition to the accumulated depreciation shown on DLC Exhibit 2, schedule C-3, page 3, column 7.

Q. What is the total for depreciation and net salvage amortization expense for the FPFTY?

A. The total is $182.778 million as shown on DLC Exhibit 2, Schedule 17, page 3, column 7, line 51.

E. Income Taxes

Q. Please describe the income tax calculation shown on DLC Exhibit 2, Schedule D-18.

A. This schedule calculates the pro forma income tax expense for the FPFTY pro forma at present rates for the total Company with pro forma adjustments in columns 2 to 5 and for the PA Jurisdiction at present rates, on the proposed increase and at proposed revenue levels in columns 6 to 9. Page 2 contains various elements used in the calculation of income taxes such as state and Federal tax depreciation, repair deductions, cost of removal and deferred income tax expense for both transmission and distribution operations. Finally, page 3 shows the calculation of the gross revenue conversion factor ("GRCF") which is used to calculate the revenue increase required once the amount of net operating income increase is determined.

Q. Who is responsible for the calculations and the data contained on Schedule D-18?

A. I am responsible for all of the calculations on Schedule D-18, Mr. Simpson and Mr. Gorman have reviewed them and agree with the calculations on page 1 of the schedule. With regard to the data, I have provided the data related to the total Company shown in columns 2 to 5, Mr. Simpson provided the data related to the separate tax components for both total Company and PA Jurisdictional operations and Mr. Gorman provided the data related to the PA Jurisdictional operations shown in columns 6 to 9.

Q. Do the income tax calculations use the tax rate and other requirements of the Tax Cut and Jobs Act of 2017 ("TCJA")?

A. Yes, they do. As further described by Mr. Simpson in his testimony (DLC St. No. 11), the tax calculations us the 21% tax rate and other elements of the TCJA.

Q. What is contained on page 2 of DLC Exhibit 2, Schedule D-18?

A. Page 2 contains the tax depreciation and other tax elements used in the calculation of income tax expense on page 1 of Schedule D-18 for the total Company in columns 2 to 4 and for the PA Jurisdictional operations in column 5.

Q. Please describe page 3 of Schedule D-18.

A. Page 3 shows the calculation of the GRCF on lines 1 to 10 of 1.515790, which includes provision for uncollectible expenses, the GRT and various assessments on revenue which results in an effective composite income tax rate of 26.805% of gross revenue. The GRCF for just income taxes of 1.406314 is calculated on lines 13 to 18 with a composite income tax rate of 28.892%.

V. FUTURE TEST YEAR AND HISTORIC TEST

Q. Please describe the process used to prepare the pro forma FTY and HTY presentation contained in DLC Exhibit 3 and DLC Exhibit 4 respectively.

A. The basic process was the same as described in connection with DLC Exhibit 2, including the preparation of a Jurisdictional Separation Study based on the FTY and HTY data, except that I used budgeted data for the FTY and actual recorded data for the HTY as the starting point for each exhibit. As with the FPFTY, I reviewed the budgeted and recorded data and, where appropriate, made pro forma adjustments. In addition, I used data from DLC Exhibit 2 as the basis for several of the pro forma amounts used in DLC Exhibits 3 and 4. Mr. Gorman will testify to the Jurisdictional Separation Study and the results which are applicable to the FTY and HTY (DLC St. No. 14).

Q. What assumptions did you make to determine what pro forma adjustments would be necessary for the FTY and HTY?

A. I included pro forma adjustments that reflected the annualization and normalization of FTY and HTY elements and also adjustments for future events that have impacted the FPFTY. The pro forma adjustments for the FTY and HTY are numbered consistent with the adjustments for the FPFTY. For example, the adjustment for salaries and wages is on Schedule D-7 in all three test years to facilitate reference between the FPFTY, the FTY and the HTY. Where there is no adjustment required for the FTY or the HTY it will simply show that it is not applicable.

Q. Referring now to DLC Exhibit 3, for the FTY, what is contained on Schedules B-1 to B-8?

A. These schedules contain forecast financial data for the year ended December 31, 2018 and are supported by Messrs. Ankrum, Simpson, Milligan and Moul as indicated on each schedule.

Q. Please describe Schedules B-6 to B-8.

A. This contains the pro forma capital structure and rate of return used for the FTY. As shown on lines 1 to 4, the Company is using the capital structure and cost rates for the FPFTY which represents the Company's expected capital structure at FPFTY end and I believe should be used for the FTY presentation as well as for the FPFTY. Schedules B-7 and B-8 reflect the same data as shown for the FPFTY.

Q. Please describe Schedule C-1.

A. Schedule C-1, which will be supported by me and Mr. Gorman, shows the measures of value and pro forma return at present rates for the total electric utility and for the Pennsylvania jurisdiction. In addition, it shows the pro forma return at proposed rates for the Pennsylvania jurisdiction.

Q. What is contained in Schedule C-2?

A. Schedule C-2 contains 4 pages and shows the utility plant in service balances at December 31, 2018 as well as the additions, retirements and adjustments for the year ended December 31, 2018. Page 1 a summary of the recorded plant, adjustments and pro forma plant by major FERC plant category. Page 2 contains the projected plant balances pro forma by FERC account at December 31, 2018 while page 3 shows the plant additions, retirements and reclassifications for the year 2018. Page 4 reflects any adjustments to plant. The total pro forma plant in service at the end of the FTY, $4.340 billion is shown on line 7 of Schedule C-2, page 1 and also on Schedule D-1, page 3, column 1, line 1 for the total Company. The PA Jurisdiction plant amount is $3.323 billion as shown in column 2 on line 1.

Q. Please describe Schedule C-3.

A. Schedule C-3 contains 4 pages and presents the accumulated depreciation at December 31, 2018. These pages reflect pro forma balances by FERC account following the same procedures used in the FPFTY. The accumulated depreciation at the end of the FTY is $1.394 billion as shown on line 7 and also on Schedule D-1, page 3, column 1, line 2 for the total Company. The PA Jurisdiction accumulated depreciation amount is $1.096 billion as shown in column 2 on line 2.

Q. What is contained in Schedule C-4?

A. Schedule C-4 contains 10 pages that show the calculation of the CWC allowance for the FTY of $64.633 million (line 6) and also on Schedule D-1, page 3, column 1, line 4.

Q. Please describe page 2 of 10 of Schedule C-4.

A. Page 2 provides a summary of the calculations for each of the elements of the CWC for the FTY. The expenses in column 2 and those included in the determination of the lead-lag amounts for taxes and interest are the pro forma amounts for the FTY while the prepayment amount is the thirteen-month average through December 31, 2017. The resulting $64.633 million of CWC shown on line 19 is brought forward to Schedule D-1, page 3 in the calculation of the measures of value. In addition, the CWC amount for the generation expense calculated on lines 16 to 18 is assigned to the Supply sector by Mr. Gorman in his JSS and is not included in the distribution sector.

Q. Please describe pages 3 to 10 of Schedule C-4.

A. These pages show the calculations of various leads and lags and working capital requirements for the FTY following the same procedures used for the FPFTY as described in connection with DLC Exhibit 2, Schedule C-4. While the amounts for the FTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same and were described in connection with the same DLC Exhibit 2 schedules.

Q. What is contained on Schedule C-5?

A. Schedule C-5 shows the 13-month average month end balance for the period December 2016 to December 2017 for plant materials and operating supplies. The 13-month average of $23.523 million is shown on line 22 in column 2 and also on Schedule D-1, page 3, column 1, line 5.

Q. Please describe the calculations on Schedule C-6.

A. These calculations present the ADIT for the FTY. The procedures followed are the same as those utilized for the ADIT calculation at the end of the FPFTY except that year-end December 31, 2018 balances were used. The resulting ADIT of $668.450 million for the FTY is shown on line 6 and also on Schedule D-1, page 3, column 1, line 11.

Q. Please describe the data presented on Schedule C-7.

A. Schedule C-7 shows the 13-month average month end balance for the period December 2016 to December 2017 customer deposits in column 1 and also for the 12-month interest expense related to those customer deposits in column 2. The 13-month average of $10.824 million is shown on line 15 in column 1 and also on Schedule D-1, page 3, column 1, line 9. The interest expense of $290,000 is shown in column 2 on line 14 and also included on Schedule D-3, page 2, column 19, line 51 as an adjustment to FTY expenses.

Q. Please describe Schedule C-8.

A. Schedule C-8 shows the FTY amount for the capitalized pension adjustment. As with the presentation for the FPFTY, the amount of $105.839 million in column 3 on line 25 is the capitalized pension adjustment and also included on Schedule D-1, page 3, column 1, line 6.

Q. Please describe Schedule C-9.

A. This schedule shows the average for Customer Advances for Construction ("CAC") for the 13 months ended December 31, 2017. This balance, $1.839 million is shown on line 16 of Schedule C-9 and is a deduction from the measures of value.

Q. What is presented on Schedule D-1?

A. Schedule D-1, contains the jurisdictional distribution amounts which will be supported by Mr. Gorman and shows the net operating income at present rates for the FTY, the pro forma revenue deficiency and the pro forma required revenue level for the Pennsylvania Jurisdiction. I support the total company amounts shown in Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows revenue and expenses recorded for the FTY, pro forma adjustments and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5 and explained in connection with other supporting schedules to be described later in my testimony.

Q. Did you prepare a schedule showing that the Cost Element expenses related to surcharge expenses and below-the-line expenses were removed from the

Cost Element expenses before using the FTY expenses in determining total Company or jurisdictional related expenses?

A. Yes, I did. The schedule is included as Exhibit RLO-2 to my testimony and with the addition of a column reducing FTY operating expenses for the reclassification of expenses to purchased energy, it is similar to Exhibit RLO-1 for the FPFTY. The net expenses shown in column 8 reflect the base for expenses in the FTY.

Q. Please describe Schedule D-3.

A. Schedule D-3 contains two pages which present a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes-other than income taxes. Each of the adjustments will be described in connection with the specific schedule containing the calculation of the adjustment.

Q. Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the FTY recorded revenue. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5C.

Q. Please describe the adjustment on Schedule D-5A.

A. This adjustment, as with the adjustment to the FPFTY, removes the surcharge revenues from the FTY. Surcharge related expenses were removed from the Cost Elements before those Cost Element amounts were used as a base for the expense adjustments in the FTY.

Q. What is adjustment on Schedule D-5B?

A. This adjustment shows the calculation of revenue losses from activities of the Company and its customers for the years 2020 to 2022 and the average for those years. This adjustment is described in connection with the adjustment to the FPFTY.

Q. Please describe the adjustment on Schedule D-C.

A. This adjustment annualizes revenues for customer growth during the FTY. The process utilized is as described in connection with the same adjustment for the FPFTY on DLC Exhibit 2, Schedule D-5C.

Q. Are the adjustments on Schedule D-6A pages 1 and 2 similar to the adjustments included in DLC Exhibit 2 and described in connection with the schedule presented in that exhibit?

A. Yes, they are.

Q. Please describe Schedule D-7.

A. Schedule D-7 annualizes salaries and wages for the FTY. Page 1 shows the budgeted amounts in column 2 and the pro forma adjustment in column 5 by FERC expense category. Page 2 shows the calculation of the annualization adjustment, which follows the same procedures described in connection with the FPFTY using the data from FTY for the wage increases. There was no adjustment to annualize numbers of employees on page 2, lines 12 to 18 because the level of employees was relatively constant during the FTY.

Q. Are the adjustments on Schedules D-8, D-9, D-10, D-11 and D-16 similar to the adjustments included in DLC Exhibit 2 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

Q. Please describe Schedule D-17.

A. Schedule D-17 presents adjusted depreciation and average cost of removal net of salvage amortization expense for FTY with depreciation expense annualized using plant balances at the end of the FTY and depreciation rates for the FTY supported by Mr. Spanos.

Q. Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the FTY reflecting the total Company revenue, expenses and measures of value included in the pro forma present rate data for the total Company and for the PA Jurisdictional operations at present and proposed revenue levels. As with the FPFTY, these data and calculations are sponsored by me, Mr. Simpson and Mr. Gorman.

Q. Have you reviewed the effects of the tax reform on the Company's projected costs and return on investment for 2018?

A. Yes. As Mr. Simpson has explained in his testimony (DLC St. No. 11), the Company has calculated its income tax claim for each of the FTY and FPFTY on the revised tax rates and deductions included in the Tax Cuts and Jobs Act ("TCJA"). The FTY in this case corresponds to 2018, the first year that the TCJA is effective.

Exhibit RLO-4 contains 3 pages and shows the return on measures of value of 6.97% based upon normalization and adjustments to revenues and expenses for the PA Jurisdiction for the FTY as shown on DLC Exhibit 3, Schedule D-1, page 1 of 3, column 1, line 15. This rate of return results in a 4.79% return to equity for the FTY as shown on Exhibit RLO-4, page 1, line 24. Using the equity percent in the FTY capital structure of 52.82% shown on line 25 results in a return on equity of 9.08% on line 26. These results include all of the effects of lower tax rates and flowback of excess deferred income taxes included and required by the TCJA.

Q. **Have you made any adjustments to remove any of the ratemaking adjustments to the PA Jurisdiction amounts shown in column 2 of Exhibit RLO-4?**

A. Yes. Several of the ratemaking adjustments included in DLC Exhibit 3 for the FTY are designed to annualize the effect of increases in costs during the year or to reflect ratemaking adjustments to the data for the purpose of setting prospective rates for future application. In order to calculate an expected achieved return in 2018 after reflection of the lower tax costs it is appropriate to remove these adjustments.

Q. **Please describe Exhibit RLO-4.**

A. Exhibit RLO-4 contains 3 pages. Page 1 contains 6 columns showing data from DLC Exhibit 3 in columns 1 and 2, adjustments in columns 3, 4 and 5 and adjusted FTY results in column 6. Pages 2 and 3 contain explanations of the adjustments shown in columns 3, 4 and 5 and on lines 23 and 25using the letter references next to each adjustment.

Q. **Please explain the adjustments on Exhibit RLO-4.**

A. **Adjustment A**, shown on page 2 of Exhibit RLO-4, lines 1 to 13, changes the components of the Cloud adjustment shown on DLC Exhibit 3, Schedule D-11 to reflect only those that would be in place during the FTY. For example, the removal of the $2.022 million that is scheduled to be capitalized in 2019 results in a capitalized amount in the FTY of $3.155 million as shown on lines 2 to 4. The remaining portions of Adjustment A reflect components necessary to show the Cloud adjustment for the FTY. Since the total Company adjustment for the Cloud capitalization is included as distribution, no further allocation is necessary.

Adjustment B on lines 11 to 13 removes the adjustment for the lost revenue as described in connection with DLC Exhibit 3, Schedule 5-B since the FTY lost revenue is included in the FTY budget and the adjustment recognizes future activity. The total Company adjustment for the revenue loss is included as distribution and therefore no further allocation is necessary.

Adjustment C on lines 14 to 16 removes the annualization of revenue for increases in customer levels at the end of the FTY. Since the total Company adjustment for the revenue annualization is included as distribution, no further allocation is necessary.

Adjustment D on lines 17 to 19 removes the annualization of salaries and wages expense for rate changes during the FTY. The amount of the total Company adjustment for salaries and wages is reduced by the salaries and wages factor from the JSS as shown on lines 18 and 19 and the $1.449 million is removed from the distribution expenses.

Adjustment E on lines 20 to 22 removes the pro forma adjustment to normalize pension expense for the FTY. The removal or the $11.434 million normalization adjustment results in a FTY expense for the total Company of $18.6 million which was included in the FTY budget. The budget amount of $18.6 million reflects the expense portion of the Company's contribution commitment for the year 2018. This amount had been replaced by the lower three-year average for the years 2018 through 2020 for prospective rate-making purposes as shown on DLC Exhibit 3, Schedule D-9. The necessary adjustment to restore the total Company expense to the $18.6 million for 2018 is $11.434 million. The amount of the $11.434 million is reduced to the distribution only by the salaries and wages JSS factor on line 21 of $9.554 million shown on line 22.

Adjustment F on lines 23 to 27 removes the annualization of depreciation expense calculated on Schedule 17, page 3 of 3. The total Company adjustment of $5.965 million in column 2 on line 27 is reduced by allocation factors for each classification of plant from the JSS to provide the adjustment for the Distribution business to $4.853 million.

Adjustments G, H and I reflect the gross receipts, State income and Federal income taxes respectively. These tax adjustments reflect amounts from the adjustments to revenues and expenses discussed herein. Finally, Adjustment J shows the use of the equity ratio from the FTY capital structure in place of the FPFTY used in the Company's claim.

Adjustment J refers to the use of the equity ratio from the capital structure in the FTY.

Adjustment K shows the reduction in synchronized interest expense used in the tax calculation that results from the change in rate base and the change in the weighted cost of debt from the FPFTY used in the Company's claim and the weighted cost of debt for the FTY, as shown on lines 28 to 34.

Q. What operating income before taxes results for 2018, after such adjustments?

A. As shown on Exhibit RLO-4, column 6, line 21, the operating income after the adjustments is $131.969 million, an increase of $3.667 million over the as filed amount of $128.302 million shown in column 2 on line 21.

Q. Have all effects of the TCJA in 2018 been reflected in this calculation?

A. Yes.

Q. What overall return on measures of value and return on equity will result for Duquesne Light at current rates for the FTY of 2018, after reflection of lower taxes under TCJA?

A. The pro forma returns at present rates included in DLC Exhibit 3 are 6.97% as an overall return on measures of value (Exhibit RLO-4, column 2, line 22) and 9.08% return on equity (Exhibit RLO-4, column 2, line 26). After the adjustments discussed previously in my testimony, the overall return on measures of value is 7.18% (Exhibit RLO-4, column 6, line 22) with a resulting return on equity of 9.46% (Exhibit RLO-4, column 6, line 26).

Q. What conclusion do you reach based upon these calculations?

A. These calculations provide a reasonable estimate of the return on equity that Duquesne Light will achieve in 2018 at its current rates after reflection of the TCJA. A return on equity of 9.46% is well below the Company's claim of

10.95% supported by the testimony of Mr. Moul (DLC St. No. 12). Furthermore, it is reasonably close but still below the 9.55% authorized return on equity for gas utilities under the DSIC. As a result, I conclude that the TCJA will not cause Duquesne Light to earn an excessive return in 2018.

Q. **Referring now to DLC Exhibit 4, for the HTY, what is contained on Schedules B-1 to B-8?**

A. These schedules contain forecast financial data for the year ended December 31, 2017 and are supported by Messrs. Ankrum, Simpson, Milligan and Moul.

Q. **Please describe Schedule B-9.**

A. This contains the pro forma capital structure and rate of return used for the HTY. As shown on lines 1 to 4, the Company is using the capital structure and cost rates for the FPFTY which represents the Company's expected capital structure at FPFTY end and I believe should be used for the HTY presentation as well as for the FPFTY.

Q. **Please describe Schedule C-1.**

A. Schedule C-1, which will be supported by me and Mr. Gorman, shows the measures of value and pro forma return at present rates for the total electric utility and for the Pennsylvania jurisdiction. In addition, it shows the pro forma return at proposed rates for the Pennsylvania jurisdiction.

Q. **What is contained in Schedule C-2?**

A. Schedule C-2 contains 4 pages and shows the utility plant in service balances at December 31, 2017 as well as additions, retirements and adjustments for the year ended December 31, 2017. Page 1 shows a summary of the recorded plant, adjustments and pro forma plant by major FERC plant category. Page 2 contains the plant balances pro forma by FERC account at December 31, 2017. Page 3 shows the plant additions, retirements and reclassifications for the year 2017 while adjustments to plant are reflected on page 4 of Schedule C-2. The total pro forma plant in service at the end of the HTY, $4.118 billion is shown on line 7 of Schedule C-2, page 1, column 4 and also on Schedule D-1, page 3, column 1, line 1 for the total Company.

Q. Please describe Schedule C-3.

A. Schedule C-3 contains 4 pages and presents the accumulated depreciation at December 31, 2017. These pages reflect the pro forma balances by FERC account following the same procedures used in the FPFTY for the HTY. The accumulated depreciation at the end of the FTY is $1.311 billion as shown in column 4 on line 7 and also on Schedule D-1, page 3, column 1, line 2 for the total Company.

Q. What is contained in Schedule C-4?

A. Schedule C-4 contains 10 pages that show the calculation of the CWC allowance for the HTY of $35.337 million (line 6) and also on Schedule D-1, page 3, column 1, line 4.

Q. Please describe page 2 of 10 of Schedule C-4.

A. Page 2 provides a summary of the calculations for each of the elements of the CWC for the HTY. The expenses in column 2 and those included in the determination of the lead-lag amounts for taxes, interest and preferred dividends are the pro forma amounts for the HTY while the prepayment amount is the thirteen-month average through December 31, 2017. The resulting $35.337

million of CWC shown on line 19 is brought forward to Schedule D-1, page 3 in the calculation of the measures of value. In addition, the CWC amount for the generation expense calculated on lines 16 to 18 is assigned to the Supply sector by Mr. Gorman in his JSS and is not included in the distribution sector.

Q. Please describe pages 3 to 10 of Schedule C-4.

A. These pages show the calculations of various leads and lags and working capital requirements for the HTY following the same procedures used for the FPFTY as described in connection with DLC Exhibit 2, Schedule C-4. While the amounts for the HTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same and were described in connection with the same DLC Exhibit 2 schedules.

Q. What is contained on Schedule C-5?

A. Schedule C-5 shows the 13-month average month end balance for the period December 2016 to December 2017 for plant materials and operating supplies. The 13-month average of $23.523 million is shown on line 16 in column 3 and also on Schedule D-1, page 3, column 1, line 5.

Q. Please describe the calculations on Schedule C-6.

A. These calculations present the ADIT for the HTY. The procedures followed are the same as those utilized for the ADIT calculation at the end of the FPFTY except that year-end December 31, 2017 balances were used. The resulting ADIT of $633.127 million for the HTY is shown on line 6 and also on Schedule D-1, page 3, column 1, line 11.

Q. Please describe the data presented on Schedules C-7.

A. Schedule C-7 shows the 13-month average month end balance for the period December 2016 to December 2017 customer deposits in column 1 and also for the 12-month interest expense related to those customer deposits in column 2. The 13-month average of $10.824 million is shown on line 15 in column 1 and also on Schedule D-1, page 3, column 1, line 9. The interest expense of $290,000 is shown in column 2 on line 14 and also included on Schedule D-3, page 2, column 19, line 51 as an adjustment to HTY expenses.

Q. Please describe Schedule C-8.

A. Schedule C-8 shows the HTY amount for the capitalized pension adjustment. As with the presentation for the FPFTY, the amount of $102.839 million in column 3 on line 25 is total amount for the capitalized pension adjustment.

Q. Please describe Schedule C-9.

A. This schedule shows the average for Customer Advances for Construction ("CAC") for the 13 months ended December 31, 2017. This balance, $1.839 million is shown on line 16 of Schedule C-9 and is a deduction from the Measures of Value.

Q. What is presented on Schedule D-1?

A. Schedule D-1, contains the jurisdictional distribution amounts which will be supported by Mr. Gorman and shows the net operating income at present rates for the HTY, the pro forma revenue deficiency and the pro forma required revenue level for the Pennsylvania Jurisdiction. I support the total company amounts shown in Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows revenue and expenses recorded for the HTY, pro forma adjustments and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5 and explained in connection with other supporting schedules to be described later in my testimony.

Q. Did you prepare a schedule showing that the Cost Element expenses related to surcharge expenses and below-the-line expenses were removed from the Cost Element expenses before using the HTY expenses in determining total Company or jurisdictional related expenses?

A. Yes, I did. The schedule is included as Exhibit RLO-3 to my testimony and with the addition of a column reducing HTY operating expenses for the reclassification of expenses to purchased energy, it is similar to Exhibit RLO-1 for the FPFTY and Exhibit RLO-2 for the FTY. The net expenses shown in column 8 reflect the base for expenses in the HTY.

Q. Please describe Schedule D-3.

A. Schedule D-3 contains two pages which present a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes-other than income taxes. Each of the adjustments will be described in connection with the specific schedule containing the calculation of the adjustment.

Q. Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the HTY recorded revenue. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5C.

Q. Please describe the adjustment on Schedule D-5A.

A. This adjustment, as with the adjustment to the FPFTY, removes the surcharge revenues from the HTY. Surcharge related expenses were removed from the Cost Elements before those Cost Element amounts were used as a base for the expense adjustments in the HTY.

Q. What is adjustment on Schedule D-5B?

A. This adjustment shows the calculation of revenue lost from conservation and energy efficiency activities of the Company and its customers for the years 2020 to 2022 and the average for those years. This adjustment is described in connection with the adjustment to the FPFTY.

Q. Please describe the adjustment on Schedule D-5C.

A. This adjustment annualizes revenues for customer growth during the HTY. The process utilized is as described in connection with the same adjustment for the FPFTY on DLC Exhibit 2, Schedule D-5C.

Q. Please describe Schedule D-7.

A. Schedule D-7 annualizes salaries and wages for the HTY. Page 1 shows the budgeted amounts in column 2 and the pro forma adjustment in column 5 by FERC expense category. Page 2 shows the calculation of the annualization adjustment, which follows the same procedures described in connection with the

FPFTY using the data from HTY for the wage increases. There was no adjustment to annualize numbers of employees on page 2, lines 12 to 18.

Q. Are the adjustments on Schedules D-8, D-9, D-10, D-11 and D-16 similar to the adjustments included in DLC Exhibit 2 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

Q. Please describe Schedule D-17.

A. Schedule D-17 presents adjusted depreciation and cost of removal net of salvage amortization expense for HTY annualized for plant amounts at the end of the HTY.

Q. Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the FTY reflecting the total Company revenue, expenses and measures of value included in the pro forma present rate data for the total Company and for the PA Jurisdictional operations at present and proposed revenue levels. As with the FPFTY, these data and calculations are sponsored by me, Mr. Simpson and Mr. Gorman.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

Duquesne Light Company
Operating Expense
By Cost Element

Actual 2015 to 2017
Budget FTY (12/31/18) & FPFTY (12/31/19)

Line #	Acct #	Account Description	[1] 2015 Actual	[2] 2016 Actual	[3] HTY 2017 Actual	[4] FTY 2018 Projected	[5] FPFTY 12/31/19 Pro Forma	[6] PRO FORMA FPFTY Removal of Surcharge Expenses	[7] PRO FORMA FPFTY Remove Below-the-Line Expenses	[8] PRO FORMA FPFTY FPFTY 12/31/19 Forecast Sum [5] to [8]
1	10	STRAIGHT-TIME LABOR	51,927	55,668	55,489	71,347	75,472	(437)	(202)	74,833
2	11	OVERTIME LABOR	6,885	6,334	6,317	5,310	5,963			5,963
3	12	PAID FOR TIME NOT WORKED	8,735	9,844	8,611	(2,623)	(2,615)			(2,615)
4	-	Total S&W to Expense	67,547	71,846	70,417	74,034	78,820	(437)	(202)	78,181
5	15	INCENTIVE COMPENSATION -	4,073	5,140	7,615	7,798	7,969	(15)	(17)	7,937
6	50	MISC EMPLOYEE BENEFITS	11,719	10,570	11,735	13,702	11,722			11,722
7	60	PENSION COSTS	18,602	18,600	18,606	18,600	5,000			5,000
8		Subtotal Labor and Fringes	101,941	106,156	108,373	114,134	103,511	(452)	(219)	102,840
9	14	BUILDING RENTS	3,205	3,273	3,385	3,428	3,428			3,428
10	20	STORES ISSUES AND RETURNS	2,411	2,281	2,144	-	-			-
11	23	MATERIALS PURCHASED	2,988	2,669	2,352	4,739	4,983	(32)	(1)	4,950
12		Subtotal Materials	5,399	4,950	4,496	4,739	4,983	(32)	(1)	4,950
13	24	UTILITIES	2,197	1,906	1,837	2,004	2,004			2,004
14	30	TRANSPORTATION/WORK EQUIPMENT	2,898	2,822	2,559	2,612	2,559			2,559
15	40	PHONE SRVCS (LOCAL,LD,TOLLFREE	2,437	2,136	1,826	1,883	1,928			1,928
16	42	OTHER LEASES	-	-	7	-	-			-
17	43	SOFTWARE LEASES	1,204	1,317	3,409	4,566	4,876			4,876
18	44	INSURANCE	5,555	5,520	5,344	5,837	6,075			6,075
19	45	MOBILE PHONE / PAGER COSTS	1,946	1,527	1,561	1,568	1,593			1,593
20	46	TAXES - OTHER THAN INCOME	-	-	-					-
21	49	REGULATORY ASSESSMENTS & FEES	2,467	2,782	2,950	3,037	3,037			3,037
22	51	EMPLOYEE EXPENSES	1,423	2,113	1,826	2,370	2,412	(33)	(47)	2,332
23	-	-	-	-	-	-	-			-
24	52	COMMUNITY RELATIONS	35	-	-	2,290	2,291		(2,291)	-
25	53	SURCHARGE REVENUE OFFSETS	62,245	57,804	55,948	34,276	24,355	(23,555)		800
26	54	POLE ATTACHMENT FEES	1,769	1,760	1,749	1,760	1,760			1,760
27	55	FIBER LEASE & SONET NETWORK	3,181	3,154	3,134	4,033	5,942			5,942
28	56	DATACOM SERVICE FEE	1,918	1,918	1,917	1,918	958			958
29	57	OUTSIDE ENGINEERING SERVICES	593	334	309	419	419			419
30	58	HARDWARE/SOFTWARE MAINTENANCE	5,552	7,100	7,706	9,526	10,552	-		10,552
31	59	PROFESSIONAL SERVICES	77,139	68,617	65,393	67,562	91,638	(20,418)	(120)	71,100
32	-	-	-	-	-	-	-			-
33	61	TRANSMISS LINE/MICROWAVE RENT	1,703	2,943	3,212	-	-			-
34	65	UNCOLLECTIBLE ACCOUNTS	16,570	15,746	10,598	12,236	12,507	(3,862)		8,645
35	66	DEFERRED COSTS	(52,774)	(47,086)	(50,952)	(31,120)	(24,823)	24,823		-
36	67	CUSTOMER REIMBURSEMENTS	(1,123)	(851)	(1,429)	(917)	(928)			(928)
37	70	SS & UNEMPLOYMENT	-	-	-	-	-			-
38	71	TEMPORARY LABOR	145	16	46	-	-			-
39	72	MAILING COSTS	9	7	10	13	15			15
40	75	MEMBERSHIP DUES	485	587	759	906	940	(16)	(31)	893
41	76	BUSINESS MEALS	391	157	107	381	511	(8)	(18)	485
42	79	-	-	-	-	-	-			-
43	80	ALLOCATION CONSTRUCT INDIRECT	-	-	-	-	-			-
44	88	SUBSIDIARY REIMBURSEMENTS	(3,073)	(2,919)	(2,706)	(2,330)	(2,362)			(2,362)
45	90	AFUDC	-	-	-	-	-			-
46	91	AFUDC	-	-	-	-	-			-
47	98	BALANCES TRANSFERRED FORWARD	-	-	-		-			-
48	99	MISCELLANEOUS	(1,381)	1,394	1,905	266	-			-
49		**Subtotal Expenses**	**244,056**	**245,183**	**235,279**	**247,397**	**260,181**	**(23,553)**	**(2,727)**	**233,901**

O'Brien Testimony - Attachments As Filed 3-28-18 — **260,181**

RRM FPFTY As Filed 3-28-18

WP CC Exp'Cost Center Expense (A1 T70)

Duquesne Light Company
Operating Expense
By Cost Element
Actual 2015 to 2017
Projected and Pro Forma FTY Ended 12-31-18

Exhibit RLO-2
Witness: O'Brien

Line #	Acct #	Account Description	[1] 2015 Actual	[2] 2016 Actual	[3] HTY 2017 Actual	[4] FTY 2018 Forecast	[5] FTY 2018 Forecast	[6] PRO FORMA FTY Removal of Surcharge Expenses	[7] Remove Below-the-Line Expenses	[8] FTY 2018 Budget [7-8-9-10]
1	10	STRAIGHT-TIME LABOR	51,927	55,668	55,489	71,347	71,347	(527)	(197)	70,623
2	11	OVERTIME LABOR	6,885	6,334	6,317	5,310	5,310			5,310
3	12	PAID FOR TIME NOT WORKED	8,735	9,844	8,611	(2,623)	(2,623)			(2,623)
4	-	Total S&W to Expense	67,547	71,846	70,417	74,034	74,034	(527)	(197)	73,310
5	15	INCENTIVE COMPENSATION -	4,073	5,140	7,615	7,798	7,798	(26)	(17)	7,755
6	50	MISC EMPLOYEE BENEFITS	11,719	10,570	11,735	13,702	13,702			13,702
7	60	PENSION COSTS	18,602	18,600	18,606	18,600	18,600			18,600
8		Subtotal Labor and Fringes	101,941	106,156	108,373	114,134	114,134	(553)	(214)	113,367
9	14	BUILDING RENTS	3,205	3,273	3,385	3,428	3,428	-		3,428
10	20	STORES ISSUES AND RETURNS	2,411	2,281	2,144	-	-			-
11	23	MATERIALS PURCHASED	2,988	2,669	2,352	4,739	4,739	(33)	(1)	4,705
12		Subtotal Materials	5,399	4,950	4,496	4,739	4,739	(33)	(1)	4,705
13	24	UTILITIES	2,197	1,906	1,837	2,004	2,004			2,004
14	30	TRANSPORTATION/WORK EQUIPMENT	2,898	2,822	2,559	2,612	2,612			2,612
15	40	PHONE SRVCS (LOCAL,LD,TOLLFREE	2,437	2,136	1,826	1,883	1,883			1,883
16	42	OTHER LEASES	-	-	7	-	-			-
17	43	SOFTWARE LEASES	1,204	1,317	3,409	4,566	4,566			4,566
18	44	INSURANCE	5,555	5,520	5,344	5,837	5,837			5,837
19	45	MOBILE PHONE / PAGER COSTS	1,946	1,527	1,561	1,568	1,568			1,568
20	46	TAXES - OTHER THAN INCOME	-	-	-					
21	49	REGULATORY ASSESSMENTS & FEES	2,467	2,782	2,950	3,037	3,037			3,037
22	51	EMPLOYEE EXPENSES	1,423	2,113	1,826	2,370	2,370	(33)	(47)	2,290
23	-	-	-	-	-					
24	52	COMMUNITY RELATIONS	35	-	-	2,290	2,290		(2,290)	-
25	53	SURCHARGE REVENUE OFFSETS	62,245	57,804	55,948	34,276	34,276	(34,080)		196
26	54	POLE ATTACHMENT FEES	1,769	1,760	1,749	1,760	1,760			1,760
27	55	FIBER LEASE & SONET NETWORK	3,181	3,154	3,134	4,033	4,033			4,033
28	56	DATACOM SERVICE FEE	1,918	1,918	1,917	1,918	1,918			1,918
29	57	OUTSIDE ENGINEERING SERVICES	593	334	309	419	419			419
30	58	HARDWARE/SOFTWARE MAINTENANCE	5,552	7,100	7,706	9,526	9,526	(1,544)		7,982
31	59	PROFESSIONAL SERVICES	77,139	68,617	65,393	67,562	67,562	(25,128)	(106)	42,328
32	-	-	-	-	-	-	-			-
33	61	TRANSMISS LINE/MICROWAVE RENT	1,703	2,943	3,212					
34	65	UNCOLLECTIBLE ACCOUNTS	16,570	15,746	10,598	12,236	12,236	(3,805)		8,431
35	66	DEFERRED COSTS	(52,774)	(47,086)	(50,952)	(31,120)	(31,120)	31,120		-
36	67	CUSTOMER REIMBURSEMENTS	(1,123)	(851)	(1,429)	(917)	(917)			(917)
37	70	SS & UNEMPLOYMENT	-	-	-	-	-			-
38	71	TEMPORARY LABOR	145	16	46	-	-			-
39	72	MAILING COSTS	9	7	10	13	13			13
40	75	MEMBERSHIP DUES	485	587	759	906	906	(16)	(29)	861
41	76	BUSINESS MEALS	391	157	107	381	381	(8)	(16)	357
42	79	-	-	-	-	-	-			-
43	80	ALLOCATION CONSTRUCT INDIRECT	-	-	-	-	-			-
44	88	SUBSIDIARY REIMBURSEMENTS	(3,073)	(2,919)	(2,706)	(2,330)	(2,330)			(2,330)
45	90	AFUDC	-	-	-	-	-			-
46	91	AFUDC	-	-	-	-	-			-
47	98	BALANCES TRANSFERRED FORWARD	-	-	-	-	-			-
48	99	MISCELLANEOUS	(1,381)	1,394	1,905	266	266			266
49		**Subtotal Expenses**	**244,056**	**245,183**	**235,279**	**247,397**	**247,397**	**(34,080)**	**(2,703)**	**210,614**

O'Brien Testimony - Attachments As Filed 3-28-18
RRM FTY As Filed 3-28-18
WP CC Exp'Cost Center Expense (A1 T70)

Duquesne Light Company
Operating Expense
By Cost Element
Actual 2014 to 2016
Budget HTY Ended December 31, 2017

Exhibit RLO-3
Witness: O'Brien

Line #	Acct #	Account Description	[1] 2015 Actual	[2] 2016 Actual	[3] HTY Ended 12/31/17	[4] HTY Ended 12/31/17	[5] HTY Ended 12/31/17	[6] PRO FORMA HTY: Removal of Surcharge Expenses	[7] PRO FORMA HTY: Below-the-Line Expenses Removed	[8] PRO FORMA HTY: Ended 12/31/17 [7 - 8 - 9 -10]
1	10	STRAIGHT-TIME LABOR	51,927	55,668	55,489	55,489	55,489	(367)		55,122
2	11	OVERTIME LABOR	6,885	6,334	6,317	6,317	6,317			6,317
3	12	PAID FOR TIME NOT WORKED	8,735	9,844	8,611	8,611	8,611	(45)		8,566
4		Total S&W to Expense	67,547	71,846	70,417	70,417	70,417	(412)	-	70,005
5	15	INCENTIVE COMPENSATION -	4,073	5,140	7,615	7,615	7,615	(7)		7,608
6	50	MISC EMPLOYEE BENEFITS	11,719	10,570	11,735	11,735	11,735			11,735
7	60	PENSION COSTS	18,602	18,600	18,606	18,606	18,606			18,606
8		Subtotal Labor and Fringes	101,941	106,156	108,373	108,373	108,373	(419)	-	107,954
9	14	BUILDING RENTS	3,205	3,273	3,385	3,385	3,385	-		3,385
10	20	STORES ISSUES AND RETURNS	2,411	2,281	2,144	2,144	2,144			2,144
11	23	MATERIALS PURCHASED	2,988	2,669	2,352	2,352	2,352	(3)		2,349
12		Subtotal Materials	5,399	4,950	4,496	4,496	4,496	(3)	-	4,493
13	24	UTILITIES	2,197	1,906	1,837	1,837	1,837			1,837
14	30	TRANSPORTATION/WORK EQUIPMENT	2,898	2,822	2,559	2,559	2,559			2,559
15	40	PHONE SRVCS (LOCAL,LD,TOLLFREE	2,437	2,136	1,826	1,826	1,826			1,826
16	42	OTHER LEASES	-	-	7	7	7			7
17	43	SOFTWARE LEASES	1,204	1,317	3,409	3,409	3,409	-		3,409
18	44	INSURANCE	5,555	5,520	5,344	5,344	5,344			5,344
19	45	MOBILE PHONE / PAGER COSTS	1,946	1,527	1,561	1,561	1,561			1,561
20	46	TAXES - OTHER THAN INCOME			-	-	-			-
21	49	REGULATORY ASSESSMENTS & FEES	2,467	2,782	2,950	2,950	2,950			2,950
22	51	EMPLOYEE EXPENSES	1,423	2,113	1,826	1,826	1,826	(17)		1,809
23			-	-	-	-	-			-
24	52	COMMUNITY RELATIONS	35	-	-	-	-			-
25	53	SURCHARGE REVENUE OFFSETS	62,245	57,804	55,948	55,948	55,948	(43,055)		12,893
26	54	POLE ATTACHMENT FEES	1,769	1,760	1,749	1,749	1,749			1,749
27	55	FIBER LEASE & SONET NETWORK	3,181	3,154	3,134	3,134	3,134			3,134
28	56	DATACOM SERVICE FEE	1,918	1,918	1,917	1,917	1,917			1,917
29	57	OUTSIDE ENGINEERING SERVICES	593	334	309	309	309			309
30	58	HARDWARE/SOFTWARE MAINTENANCE	5,552	7,100	7,706	7,706	7,706	-		7,706
31	59	PROFESSIONAL SERVICES	77,139	68,617	65,393	65,393	65,393	(19,658)		45,735
32			-	-	-	-	-			-
33	61	TRANSMISS LINE/MICROWAVE RENT	1,703	2,943	3,212	3,212	3,212			3,212
34	65	UNCOLLECTIBLE ACCOUNTS	16,570	15,746	10,598	10,598	10,598	(4,982)		5,616
35	66	DEFERRED COSTS	(52,774)	(47,086)	(50,952)	(50,952)	(50,952)	43,176		(7,776)
36	67	CUSTOMER REIMBURSEMENTS	(1,123)	(851)	(1,429)	(1,429)	(1,429)			(1,429)
37	70	SS & UNEMPLOYMENT	-	-	-	-	-			-
38	71	TEMPORARY LABOR	145	16	46	46	46			46
39	72	MAILING COSTS	9	7	10	10	10			10
40	75	MEMBERSHIP DUES	485	587	759	759	759	-		759
41	76	BUSINESS MEALS	391	157	107	107	107	-		107
42	79		-	-	-	-	-			-
43	80	ALLOCATION CONSTRUCT INDIRECT	-	-	-	-	-			-
44	88	SUBSIDIARY REIMBURSEMENTS	(3,073)	(2,919)	(2,706)	(2,706)	(2,706)			(2,706)
45	90	AFUDC	-	-	-	-	-			-
46	91	AFUDC	-	-	-	-	-			-
47	98	BALANCES TRANSFERRED FORWARD	-	-	-	-	-			-
48	99	MISCELLANEOUS	(1,381)	1,394	1,905	1,905	1,905			1,905
49		Subtotal Expenses	244,056	245,183	235,279	235,279	235,279	(24,958)	-	210,321

O'Brien Testimony - Attachments As Filed 3-28-18
RRM HTY As Filed 3-28-18
WP CC Exp'Cost Center Expense (A1 T70)

Duquesne Light Company
Before The Pennsylvania Public Utility Commission
Future Test Year - 12 Months Ended December 31, 2018
($ in Thousands)

Comparative Return on Equity for 2018

Line No	Description	Factor Or Reference	[1] FTY in Exhibit 3 Total Company	[2] FTY in Exhibit 3 PA Jurisdiction for Distribution		[3] Adjustments		[4] Adjustments		[5] Adjustments		[6] Adjusted FTY for Distribution
			D-1, P 2 & 3 [1]	D-1, P 2 & 3 [2]								Sum [2] to [5]
1	Plant in Service		$ 4,340,323	$ 3,323,052		$ (2,022)	A					$ 3,321,030
2	Accumulated Depreciation		(1,393,630)	(1,095,831)		833	A					(1,094,998)
3		L 1 + L 2	2,946,693	2,227,221		(1,189)		-		-		2,226,032
4	Other Rate Base Elements		(487,118)	(387,705)								(387,705)
5	Measures of Value	L 3 + L 4	$ 2,459,575	$ 1,839,516		$ (1,189)		$ -		$ -		$ 1,838,327
	Total Operating Revenues											
6	Total Sales Revenues		$ 868,762	$ 500,269		$ 8,179	B	$ (628)	C	$ -		$ 507,820
7	Other Revenues - Off System Sales		1,400	-								-
8	Other Operating Revenues		15,189	11,666								11,666
9	Total Revenues	Sum L 6 to L 8	885,351	511,935		8,179		(628)		-		519,486
	Total Operating Expenses											-
10	Salaries & Wages	0 8356	75,044	62,707		(1,449)	D					61,258
11	Pension Expense	0.8356	7,167	5,989		9,554	E					15,543
12	Other O&M Expenses		341,008	103,818								103,818
13	Depreciation & Amortization Expense	0.8297	173,450	143,911		(631)	A	(4,853)	F			138,427
14	Taxes Other Than Income Taxes	0 0590	54,559	36,387		483	G	(37)	G			36,833
15	Total Operating Expenses	Sum L 10 to L 14	651,228	352,812		7,957		(4,890)		-		355,879
16	Operating Income Before Taxes	L 9 - L 15	234,123	159,123		222		4,262		-		163,607
	Income Taxes											
17	State	9 99%	33,420	23,577		22	H	426	H	(165)	K	23,860
18	Federal	18 90%	11,815	7,244		42	I	806	I	(313)	K	7,779
19	Total Income Taxes	L 17 + L 18	45,235	30,821		64		1,231		(478)		31,638
20	Total Operating Expenses	L 16 + L 19	696,463	383,633		8,021		(3,659)		(478)		387,517
21	Total Operating Income	L 9 - L 20	$ 188,888	$ 128,302		$ 158		$ 3,031		$ 478		$ 131,969
22	Earned Rate of Return - %	L 21 / L 5		6 97%								7 18%
23	Weighted Cost of Debt	K		2 18%	K							2 18%
24	Earned Return to Equity	L 22 - L 23		4 79%								5 00%
25	Equity Component of Capital Structure	B-7, [1], L 7		52 82%	J							52 82%
26	Return on Equity	L 24 / L 25		9 08%								9 46%

Duquesne Light Company
Before The Pennsylvania Public Utility Commission
Future Test Year - 12 Months Ended December 31, 2018
($ in Thousands)

NOTES TO ADJUSTMENTS

Line #	Adjust #	Description	[1] Factor or Reference Exhibit 3 FTY	[2] Amount	[3] Amount	[3] Total
1	A	**Remove portion of Cloud Adjustment that relates to 2019**				
		PLANT				
2		Total Plant addition for Cloud Adjustment	C-2, P-1, [3], L 1 and D-11 [3], L 6		$ 5,177	
3		Total Approved to be closed to plant by 12-31-18	D-11, [3], L 5		3,155	
4		Adjustment to remove Cloud Adjustment	L 3 - L 2			$ (2,022)
		ACCUMULATED DEPRECIATION				
5		Total Accumulated Depreciation for Cloud Adjustment	C-3, P-1, [3], L 1 and D-11, [5] L 6		$ (1,325)	
6		Total Approved Accumulated Depreciation at 12-31-18	D-11, [5] L 5		(492)	
7		Adjustment to remove portion accumulated in 2019	L 6 - L 5			$ 833
		DEPRECIATION/AMORTIZATION EXPENSE				
8		Depreciation Expense included in 2018 pro forma expenses	D-3, P-2, [1], L 55		$ 1,035	
9		Depreciation in 2018 for capitalized Cloud Expense	D-11, [4], L 5		404	
10		Adjustment to decrease Pro Forma 2018 expense	L 9 - L 8			$ (631)
	B	**REMOVE LOST REVENUE ADJUSTMENT**				
11		Remove Pro Forma adjustment for lost revenue over budget amount	D-5B, [6], L 22		$ (8,179)	
12		Amount of PF adjustment occurring in 2018	None		-	
13		Adjustment to increase 2018 PF revenue	L 12 - L 11			$ 8,179
	C	**REMOVE REVENUE ANNUALIZATION ADJUSTMENT**				
14		Pro Forma adjustment for lost revenue over budget amount	D-5C, [6], L 8		$ 628	
15		Amount of PF adjustment for course-of-the-year activity	None		-	
16		Adjustment to increase 2018 PF revenue	L 15 - L 14			$ (628)
	D	**REMOVE SALARY & WAGE ANNUALIZATION**				
17		Reverse Total Company Adjustment for S&W	D-7, P-1, [5], L 16		$ (1,734)	
18		S&W Allocator to Distribution	JSS S&W Factor for Dist		83 560%	
19		Reduction for Distribution portion of S&W annualization adjustment	L 17 * L 18			$ (1,449)

($ in Thousands)

NOTES TO ADJUSTMENTS

Line #	Adjustment #	Description	[1] Factor or Reference Exhibit 3 FTY	[2] Amount	[3] Amount	[3] Total
	E	**REVERSE PENSION ADJUSTMENT**				
20		Reverse Pension Adjustment for Total Company	D-9, [5], L 15		$ 11,434	
21		S&W Allocator to Distribution	JSS S&W Factor for Dist		83 560%	
22		Increase Distribution portion of Pension Expense	L 20 * L 21			$ 9,554
	F	**REMOVE DEPRECIATION EXPENSE ANNUALIZATION**			**JSS Factor**	
23		Intangible Plant	D-17, P 3, L 4, [7] - [6]	$ 2,475	0 9135	$ 2,261
24		Transmission Plant	D-17, P 3, L 16, [7] - [6]	699	-	-
25		Distribution Plant	D-17, P 3, L 32, [7] - [6]	1,578	1 0000	1,578
26		General Plant	D-17, P 3, L46, [7] - [6]	1,213	0 8356	1,014
27		Distribution Adjustment	Sum L 23 to L 26	$ 5,965		$ 4,853
	G	**Reflect Change in Gross Receipts Tax on Revenue Change at 5.90% times Line 10**				
	H	**Reflect State Income Tax Expense on Change in Taxable Income on Line 17 times tax rate of 9.99%**				
	I	**Reflect Federal Income Tax Expense on Change in Taxable Income on Line 17 and less State Income Tax on Line 18 times tax rate of 18.90% (1.0000 - .0999 = .9001 * .2100 = .1890)**				
	J	**Reflects use of Equity ratio for the FTY**	B-7, [1], L 7		52 82%	
	K	**Reflects use of Weighted Debt Cost for the FTY in calculation of interest expense for the income tax expense calculation and in determination of ROE**			2 18%	
28		Measures of Value	Attach D, P-1, [2], L 5			$ 1,839,516
29		Weighted Cost of Debt in Claim	B-6, [5], L 1		2 09%	
30		Weighted Cost of Debt in FTY	Update for FTY		2 18%	
31		Change in Weigted Cost of Debt	L 30 - L 29			0 0009
32		Change in Interest Expense	L 28 * L 31			$ 1,656
33		Reduction in State Income Tax	L 32 * [2], L 33		9 99%	$ 165
34		Reduction in Federal Income Tax	L 32 * [2], L 34		18 90%	$ 313

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3000124

Duquesne Light Company

Statement No. 10

DIRECT TESTIMONY OF JOHN J. SPANOS

CONCERNING DEPRECIATION

Date: March 28, 2018

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming).

Q How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986, following graduation from college.

Q. What is your position in the firm?

A. I am a Senior Vice President.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. Will you outline your experience in the field of depreciation?

A. I have 32 years of depreciation experience which includes expert testimony in over 270 cases before approximately 40 regulatory commissions, including the Pennsylvania Public Utility Commission. Please refer to Appendix A for my qualifications.

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the utility plant of Duquesne Light Company.

Q. Have you prepared exhibits presenting the results of your studies?

A. Yes. Exhibit JJS 1 presents the results of the depreciation study as of December 31, 2017. Exhibit JJS 2 presents the results of the depreciation study as of December 31, 2018. Exhibit JJS 3 presents the results of the depreciation study as of December 31, 2019. In addition, I am responsible for the responses to the following filing requirements pertaining to depreciation under Section 53.53(a)(1) of the Commission's regulations: V-A-2, V-B-1, V-B-2, V-C-1, V-D-1, V-D-2 and V-E-1 which present summaries of the study results as of the historic test year end, December 31, 2017, future test year end, December 31, 2018 and the fully forecasted future test year end, December 31, 2019.

Q. Please describe Exhibits JJS 1, JJS 2 and JJS 3.

A. Exhibit JJS 1, titled "2017 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2017," includes the results of the depreciation study as related to the original cost at December 31, 2017. The report also includes the detailed depreciation calculations. Exhibit JJS 2, titled "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018," includes the results of the depreciation study as related to the estimated original cost at December 31, 2018. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations. Exhibit JJS 3, titled "2019 Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2019," includes the results of the depreciation study as related to the estimated original cost at December 31, 2019.

Q. What was the purpose of your depreciation study?

A. The purpose of the depreciation studies was to estimate the annual depreciation accruals related to utility plant in service for ratemaking purposes and, using Commission-approved procedures, to estimate the Company's book reserve at December 31, 2017, December 31, 2018 and December 31, 2019.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent electric base rate proceeding in Docket No. 2013-2372129.

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line, remaining life method of depreciation. For Accounts 391, 393, 394, 395, 397 and 398, the claim is based on the straight line, remaining life method of amortization. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. All depreciable accounts utilize the methods and procedures based on the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1983 and remaining lives consistent with the equal life group procedure for plant installed in 1983 and in later years.

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1983.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. There average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please describe briefly the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1983 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for many years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve utilized by the company in its last base rate proceeding.

Q. How was the book reserve used in the calculation of annual depreciation?

A. The book reserve by account was allocated to vintages to determine original cost less accrued depreciation by vintage. The total annual accrual is the sum of the results of dividing the original costs less accrued depreciation by the vintage composite remaining lives.

Q. How was the book reserve at December 31, 2018 estimated?

A. The book reserve at December 31, 2018, by account, was projected by adding estimated accruals, salvage and the amortization of net salvage, and subtracting estimated retirements and cost of removal from the book reserve at December 31, 2017. Annual accruals were estimated using the annual accrual rates calculated as of December 31, 2017. For most accounts, salvage and cost of removal were estimated by (1) expressing actual salvage and cost of removal as a percent of retirements by account, for the most recent five-year period, and (2) applying those percentages to the projected retirements by account. For the purpose of calculating the annual accruals, the projected book reserve by account was allocated to vintages based on calculated accrued depreciation at December 31, 2018.

Q. Has a service life study of the Company's electric utility property been performed?

A. No, not for this filing, because this Commission's regulations only require service life studies to be prepared every 5 years. The Company's most recent service life study was performed using data through 2014. That service life study is the basis for the service lives I used to calculate annual accruals.

Q. Briefly outline the procedure used in performing the service life study.

A. The service life study consisted of assembling and compiling historical data from the records related to the electric utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as large service centers, substation structures, and office buildings within Accounts 352, 361 and 390.1. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the electric plant through 2014. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. What was the source of these data?

A. They were assembled from Company records related to its utility plant in service.

Q. Were the methods used in the service life study the same as those used in other depreciation studies for electric utility plant presented before this Commission?

A. Yes. The methods are the same ones that have been presented previously for Duquesne Light Company and for other electric companies before the Pennsylvania Public Utility Commission and that have been accepted by the Commission in its past orders concerning electric utilities.

Q. What approach did you use to estimate the lives of significant structures such as substation buildings, office buildings and service centers?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. Has your firm used this approach in other proceedings before this Commission?

A. Yes, we have used the life span technique on many occasions before the Pennsylvania Public Utility Commission.

Q. What are the bases for the probable retirement years that you have estimated for each structure?

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar structures. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, analysis of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the structure's life span.

Q. Are the factors considered in your estimates of service life presented in Exhibit JJS 2?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages III-4 through III-6 of Exhibit JJS 2.

Q. Please outline the contents of Exhibit JJS 2.

A. Exhibit JJS 2 is presented in seven parts. Part I, Introduction, sets forth the scope and basis of the study. Part II, Estimation of Survivor Curves, includes a description of the

Iowa Curves and the formulation of the retirement rate method. Part III, Service Life Considerations, and Part IV, Calculation of Annual and Accrued Depreciation, include a description of the judgment utilized for life parameters and the explanation of depreciation procedures.

Part V, Results of Study, presents a description of the results and summaries of the depreciation calculations. Part VI, Service Life Statistics, presents the graphs and tables which relate to the service life study. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations by account.

Table 1, pages V-4 and V-5, presents the estimated survivor curve, the original cost at December 31, 2018, and the book reserve and calculated annual depreciation for each account or subaccount of Electric Plant. Table 2, pages V-6 and V-7, presents the bring-forward to December 31, 2018, of the book depreciation reserve as of December 31, 2017. Table 3 on page V-8 sets forth the calculation of the annual accruals used in the bring-forward. Table 4, page V-9, presents the experienced and estimated net salvage by function during the five-year period, 2014 through 2018.

The section beginning on page VI-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VII-1 presents the depreciation calculations related to original cost. The tabulations on pages VII-2 through VII-120 present the calculation of annual depreciation by vintage by account for each depreciable group of utility plant.

Q. Please outline the contents of Exhibit JJS 3.

A. Exhibit JJS 3 includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of December 31, 2019. The descriptions and explanations presented in Exhibit JJS 2 are also applicable to the depreciation calculations presented in Exhibit JJS 3. The graphs and tables related to service life presented in Exhibit JJS 2 also support the service life estimates used in Exhibit JJS 3 inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of December 31, 2019, are organized and presented in the same manner as those as of December 31, 2018.

Q. Please outline the contents of Exhibit JJS 1.

A. Exhibit JJS-1 includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of December 31, 2017. The descriptions and explanations presented in Exhibit JJS 2 are also applicable to the depreciation calculations presented in Exhibit JJS 1. The graphs and tables related to service life presented in Exhibit JJS 2 also support the service life estimates used in Exhibit JJS 1, inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of December 31, 2017, are organized and presented in the same manner as those as of December 31, 2018.

Q. Please use an example to illustrate the manner in which the study is presented in Exhibit JJS 2.

A. I will use Account 365.01, Overhead Conductors and Devices, as my example; inasmuch as it is one of the larger depreciable groups and represents 13 percent of the original cost of depreciable utility plant as of December 31, 2018.

The retirement rate method was used to analyze the survivor characteristics of this group. The life table for the 1964-2014 experience band is presented on pages III-73 through III-

78 of Exhibit JJS 2. The life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 48-R1, on page III-72.

The calculation at December 31, 2018, is presented on pages III-168 and III-169 of Exhibit JJS 2 and is based in part on the bring-forward of the book reserve. The tabulation in Exhibit JJS 2 sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to the table on page III-4 in Exhibit JJS 2.

Q. Do you believe Exhibit JJS 2 reflects the appropriate survivor curves for Duquesne Light Company to be adopted in this proceeding?

A. Yes, I do. The methods and procedures utilized in the development of survivor curves are consistent with past practices for Duquesne Light Company and Pennsylvania ratemaking regulations. The service life study was completed as of December 31, 2014.

Q. Do you believe that the annual depreciation rates and the related depreciation expense claims should be adopted in this proceeding?

A. Yes, I do. The depreciation rates and expense claims are based on appropriate survivor curves and the depreciation procedures are the same as those approved in past filings before this Commission.

Q. In what manner is net salvage incorporated in the depreciation calculations?

A. As stated on page I-4 of Exhibit JJS 2, no adjustment for net salvage was made to the calculated annual depreciation amounts. The total calculated annual depreciation set forth on page II-4 of Exhibit JJS 1, page V-5 of Exhibit JJS 2 and on page II-4 of Exhibit JJS 3 should include an addition for the amortization of negative net salvage in accordance with the practice of this Commission. The amortization is based on experience during the period 2013 through 2017 for the calculation as of December 31, 2017, and on experience during the period 2014 through December 31, 2017, plus estimates for the twelve months of 2018 for the calculation as of December 31, 2018.

The amortization for the December 31, 2019 calculation is based on experience during the period 2015 through December 31, 2017, plus estimates for the period January 2018 through December 2019. The amounts of the five-year amortizations are calculated in Table 2 on page II-5 of Exhibit JJS 1, in Table 4 on page V-9 of Exhibit JJS 2 and in Table 4 on page II-8 of Exhibit JJS 3.

Q. Does this complete your testimony at this time?

A. Yes, it does.

<u>**Appendix A**</u>

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. **Please state your name.**

A. My name is John J. Spanos.

Q. **What is your educational background?**

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. **Do you belong to any professional societies?**

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. **Do you hold any special certification as a depreciation expert?**

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. **Please outline your experience in the field of depreciation.**

A. In June, 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June, 1986 through December, 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January, 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July, 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December, 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and in April 2012, I was promoted to my present position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC). In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso

Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas

Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company and Northern Illinois Gas Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. **Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?**

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal

Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. **Have you had any additional education relating to utility plant depreciation?**

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. **Does this conclude your qualification statement?**

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Co.	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Co.	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Co.	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Co.	Depreciation
18.	2003	FERC	ER-03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
32.	2005	IL CC	05-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	FERC		Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Co.	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Co.	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Co.	Depreciation
47.	2006	NC Util Cm.		Pub. Service Co. of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS082, ETC. AL	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Co.	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co.-Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Co.	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Co.	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	09-	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Co.	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Co.	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Co.	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Co.	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Co.	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Co.	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Co.	Depreciation
119.	2010	IN URC		Northern Indiana Public Serv. Co. - NIFL	Depreciation
120.	2010	IN URC		Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	Lancaster, City of – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
130.	2011	Il CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Co.	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation
133.	2011	FERC	2011-2232243	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Hanover, Borough of – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Co.	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
153.	2012	TX PUC		Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Co.– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Co.	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Co.	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation

	Year	Jurisdiction	Docket No.	Client Utility	Subject
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Co. – PEPCO	Depreciation
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Co.	Depreciation
167.	2013	FERC	ER13- -0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13- -0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Co.	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14-	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Hanover, Borough of – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	Suez Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Commission	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Co. – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Co. – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC		Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UT&C	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Oklahoma, Public Service Company of	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER17-___	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC		SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
276.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3000124

Duquesne Light Company

Statement No. 11

DIRECT TESTIMONY OF MATTHEW L. SIMPSON

Dated: March 28, 2018

I. INTRODUCTION AND QUALIFICIATIONS

Q. Please state your full name, business affiliation and business address.

A. My name is Matthew L. Simpson. I am the Director, Tax at Duquesne Light Company ("Duquesne Light" or "Company"). The Company's business address is 411 Seventh Avenue, Pittsburgh PA 15219.

Q. How long have you worked at Duquesne Light?

A. I have been with Duquesne Light since May 2011.

Q. What are your current responsibilities?

A. In general, I oversee and manage the overall tax function for DQE Holdings, LLC ("DQE") and its subsidiaries, including Duquesne Light Holdings, Inc. ("DLH") and its wholly owned subsidiary, Duquesne Light. I am responsible for ensuring the accuracy and completeness of the Company's income tax provision for its financial statements and regulatory filings. I am also responsible for all tax compliance filings with the various taxing authorities as well as managing audit examinations.

Q. What are your qualifications, work experience and educational background?

A. I am a Certified Public Accountant and an active member of both the American Institute of Certified Public Accountants and Pennsylvania Institute of Certified Public Accountants. Prior to joining Duquesne Light, I held the position of Tax Director at a large multi-national construction company headquartered in Pittsburgh, PA. Before joining private industry, I held various positions in public accounting firms where I managed compliance and advisory services for clients in various industries, including the energy, construction and manufacturing sectors. I hold a Bachelor of Science Degree in Accounting from Penn State University as well as a Master of Science Degree in Taxation that I received from Robert Morris University in Pittsburgh.

Q. **Have you previously testified before this or any other regulatory agency?**

A. I provided written testimony to the Pennsylvania Public Utility Commission for Duquesne Light Company's 2013 rate filing, Docket No. R-2013-2372129. I have also provided written testimony to the Federal Energy Regulatory Commission, Docket No. ER13-1220-000, related to a Monthly Deferred Tax Adjustment charge.

Q. **What is the purpose of your direct testimony regarding Duquesne Light's request for increased rates?**

A. The purpose of my testimony is to describe and explain Duquesne Light's tax expense and related tax information.

Q. **Are you sponsoring any exhibits as part of your direct testimony?**

A. Yes, I am. I am co-sponsoring Duquesne Light's Income Statement as it relates to taxes and the Balance Sheet as it relates to deferred and prepaid taxes. The specific schedule references are DLC Exhibit 2 (FPFTY), Exhibit 3 (FTY) and Exhibit 4 (HTY), Schedules B-1, B-2, B-5, C-6, D-16 and D-18. I am sponsoring all the Data Filing Requirements and Schedules concerning Taxes. Please see Exhibit MLS-1 to my testimony for the listing of data filing requirements that I am sponsoring. My name is at the top of each data filing requirement that I sponsor.

Q. Please explain how these exhibits were prepared?

A. All were prepared either by me or under my direction or supervision. They were prepared in accordance with Commission requirements and Internal Revenue Service procedures and guidance.

Q. Does your testimony address the impact of tax reform legislation, known as the Tax Cuts and Jobs Act of 2017 (TCJA), signed into law in December 2017?

A. Yes. Among other things, the TCJA lowers the corporate income tax rate from 35% to 21%, eliminates bonus depreciation for regulated utilities, and provides for the continuation of rate normalization requirements for accelerated depreciation benefits. I will address the impacts of the new tax law on the Company's income tax expense and related calculations throughout my testimony.

II. TAX CALCULATIONS

A. INCOME TAXES

Q. Please discuss the Company's claim for income taxes.

A. Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the flow through of accelerated tax depreciation and other accelerated tax deductions when computing current state income taxes, and the normalization method for accelerated depreciation used in the calculation of Federal income taxes.

Q. Could you explain Duquesne Light's income tax expense for the HTY?

A. For the HTY the Company has used its December 31, 2017 financial statement information to calculate its current and deferred income tax expense. The tax expense calculations were made in accordance with federal and state laws, using a federal tax rate of 35% and a Pennsylvania tax rate of 9.99%.

Q. Could you explain the Company's income tax expense calculation for the FPFTY and FTY?

A. The calculation of federal and state income tax expense is reflected on Schedule D-18 within DLC Exhibit 2 (FPFTY) and DLC Exhibit 3 (FTY). These calculations begin with revenue at present and pro forma rates, reduced by operating expenses at present and pro from rates and further reduced by synchronized interest expense to arrive at base taxable income on line 7. The synchronized interest expense deduction is calculated by multiplying the average debt cost times the debt ratio times the rate base to synchronize the interest deduction to the portion of the rate base financed by debt. State tax deductions related to property are made to arrive at state taxable income on line 17. The statutory state corporate net income tax rate (9.99%) was then applied to compute the pro forma state income tax expense shown on line 18. To compute current federal income tax expense, the base taxable income on line 7 was reduced by the calculated current state income tax expense on line 18 and by the federal tax deductions related to property shown on lines 19 through 27 to arrive at the federal taxable income shown on line 28. The Company applied the lower federal statutory corporate rate of 21%, as per the TCJA, to compute the pro forma current federal income tax expense. Federal deferred income taxes on line 33 were also computed at the lower corporate statutory tax rate of 21%. In addition, the deferred income tax expense calculation was reduced to reflect the flow through of excess deferred income taxes (EDIT) due to the reduction in the federal corporate income tax rate from 35% to 21% as per the

TCJA. No state deferred income taxes have been reflected as the tax benefits of accelerated deductions are flowed-through to customers.

Q. Please describe the Company's use of accelerated tax depreciation methods in computing its federal tax depreciation?

A. The Company uses accelerated depreciation. From 1971 to 1980 the Company elected to calculate tax depreciation under the provisions of the Class Life Asset Depreciation Range ("ADR") as provided by the Revenue Act of 1971. From 1981 to 1986 the Company elected to calculate tax depreciation under the Accelerated Cost Recovery System ("ACRS") as provided by the Economic Recovery Tax Act of 1981. From 1987 to the present the Company has elected to calculate tax depreciation under the provisions of the Modified Accelerated Cost Recovery System ("MACRS") as originally provided by the Tax Reform Act of 1986 and as modified in subsequent Acts. Prior to 2018, the tax law allowed for additional bonus depreciation deductions. However, with the enactment of the TCJA, regulated utilities are no longer permitted to take bonus depreciation in computing their annual accelerated tax depreciation deductions.

Q. Please comment on the deferred income taxes of accelerated depreciation presented in your tax expense.

A. In this rate case, Duquesne Light is reflecting deferred income taxes resulting from the adherence to IRS normalization rules and use of accelerated federal tax depreciation associated with Post -1969 Public Utility Property under the following depreciation methods: General Depreciation Rules (pre-1971), Class Life ADR (1971-1980), ACRS (1981-1986), MACRS (1987-Present).

Duquesne Light's continued entitlement to the use of accelerated depreciation provision on Post -1969 Public Utility Property for federal income tax purposes is dependent upon the use of a normalization method of accounting for the resulting deferred income tax activity in determining cost of service (and total accumulated deferred tax balance used in rate base) for rate making.

The Company computes the deferred income taxes used in the cost of service calculation based on the applicable Internal Revenue Service ("IRS") normalization regulations which are primarily based on the original in-service date of the underlying asset. Duquesne Light follows guidance within former IRC Section 167(1) and IRC Section 168(i)(9) in which depreciation timing differences of federal accelerated tax depreciation in excess of the straight line depreciation using the method for calculating the ratemaking depreciation is tax effected at the current federal tax rate. This is implemented by calculating the income tax on the difference between accelerated depreciation and straight line or book depreciation and charging that tax to customers as deferred income taxes. This amount is then added to the accumulated deferred income tax (ADIT) balance, which is deducted from rate base to give customers the benefit of the advance payment of the taxes. When these underlying depreciation timing differences reverse, the customers pay only the taxes based on the higher book depreciation deduction and the ADIT balance is reduced as the Company pays higher taxes to the IRS. Absent normalization accounting for ratemaking purposes, Duquesne Light would be required to use a straight-line method with book lives in determining its depreciation allowance for federal income tax purposes.

In accordance with Commission policy, the benefits of accelerated tax depreciation related to pre-1970 Public Utility Property and state income taxes are flowed through to customers. .

Q. **Would you explain the treatment of cost of removal in the income tax calculation?**

A. In determining the pro forma operating expenses for the cost of service, the customer is charged with removal costs of retired plant through the net negative salvage adjustment. The customer is also entitled to receive the benefit of any reduction of income taxes which results from including this adjustment in the pro forma income tax calculation. Thus, the current tax deduction for cost of removal, net of salvage, has been reflected as a flow-through benefit to the rate payers in each of the test years.

Q. **Are there other items treated as flow-through in the rate-making process used to determine income tax expense?**

A. Yes. Based on prior Commission orders, the income tax and thus rate-reducing benefits of the following items have been flowed through to current ratepayers: (1) the state tax effect of timing differences related to book versus state tax method and life depreciation differences on all vintaged property; (2) the federal tax effect of the cumulative timing differences related to book versus federal tax method and life depreciation differences on pre-1971 vintaged property before the adoption of Class Life Asset Depreciation Range ("CLADR"); (3) the federal tax effect of the cumulative timing differences related to the book versus federal tax life on vintage property during tax years 1971 through 1980, prior to adoption of the Accelerated

Cost Recovery System ("ACRS") / Modified Accelerated Cost Recovery System ("MACRS"); (4) the state income tax effects associated with basis differences between ratemaking balances and the income tax basis of plant,; and (5) the federal and state tax effects of timing differences related to the book versus tax treatment of cost of removal and salvage.

Q Are there any investment tax credits the Company has reflected in the income tax calculations for this rate filing?

A. No. All investment tax credits were fully amortized in 2010.

B. ACCUMULATED DEFERRED INCOME TAXES

Q. Could you explain how you have accounted for deferred income taxes in this filing?

A. Federal accumulated deferred income taxes ("ADIT") related to plant in service are recorded in account 282 and have been deducted from rate base. Consistent with prior rate case filings, it is appropriate to reduce these amounts by the ADIT related to the prepayments on income taxes related to contributions-in-aid of construction. Consistent with my understanding of Commission practices, there is no ADIT balance related to state income taxes on property because the tax benefits of accelerated depreciation are flowed through to customers.

Q. Please explain the Accumulated Deferred Income Taxes reflected on Schedule C-6?

A. The ADIT balance at the end of the respective test year reflects the cumulative deferred income taxes on the Company's property that has been reflected in cost of service, including tax deferrals related to Accelerated Cost Recovery System

("ACRS") and Modified Accelerated Cost Recovery System ("MACRS") property. The applicable ACRS/MACRS legislation provides for normalization of federal tax benefits on post-1980 property. In addition, the Company was required by prior rate settlements to normalize the federal tax benefits associated with tax repairs and Section 263A costs related to ACRS/MACRS property. For the fully projected test year ended December 31, 2019, the incremental deferred tax liability arising from items discussed are calculated on a pro rata basis in accordance with Treasury Regulation Sec. 1.167(l)-1(h)(6)(ii).

Q. Has Duquesne Light implemented an accounting method for 263A costs?

A. Yes. In 2016, Duquesne Light filed an automatic method change to adopt the capitalization of mixed service costs as prescribed by the IRS Industry Directive #5 and reflected a cumulative IRC Section 481(a) "catch up adjustment" of $56 million in its 2016 income tax return.

Q. How did Duquesne Light reflect the income tax benefit of the 263A tax accounting method change in its deferred taxes?

A. Similar to its tax repairs accounting method change from the 2010 Joint Settlement and in accordance with Paragraph 37 of the 2013 Joint Petition for Settlement at Docket No/R-2013-2372129, the Company recorded the IRC Section 481(a) "catch up" adjustment as a reduction to its income tax liability and an offsetting credit to account 282 on its regulated books of account. The recording of this adjustment increased ADIT and reduced the Company's rate base.

Q. How has Duquesne Light provided for tax repairs and 263A costs in the HTY, FTY and FPFTY income tax calculations?

A. The 2010 and 2013 Joint Petition for Settlements stipulated that the ongoing current deduction would be reflected in the same manner as the "catch up" adjustment. Applying the same percentage of tax repairs and 263A costs to total capital additions obtained from the tax accounting method change calculations, an estimate of the current tax repairs and 263A deductions were computed based on this historical percentage applied to the capital additions for each test year. Federal deferred income taxes were computed on the annual tax repair and 263A deductions; resulting in an increase to account 282 – ADIT and reducing the Company's rate base. The state income tax benefit of the tax repairs and 263A deductions related to distribution property is being flowed through to the ratepayers.

Q. How has the Duquesne Light provided for accumulated deferred income taxes related to the pension rate base adjustment?

A. During Duquesne Light's 2010 rate case, the Commission adopted a settlement provision in which the Company would be allowed to include a rate base adjustment for the portion of the 50% of actual pension contributions that is treated as capitalized in the ratemaking process over the amount that is actually capitalized to plant accounts under the SFAS 87 capitalized pension (hereafter referred to as "Capitalized Pension Adjustment") from 2007 forward, net of related accumulated deferred income taxes. The Company has reflected the Capitalized Pension Adjustment amounts as part of its tax plant and has included all tax depreciation and related ADIT in account 282. The effect is that the offset for tax depreciation deductions on the increase in tax plant is already reflected in the Account 282 ADIT deducted from rate base in the Company's test years. The fact that the Commission is allowing the Company to reflect the Capitalized Pension Adjustment in rate base does not change (increase or decrease) the tax position required by the IRS and reflected on the Company's books and tax records. No separate ADIT adjustment is necessary as the deferred tax impacts of the Capitalized Pension Adjustment are already included in the Company's 282 Account and reflected in rate base.

Q. How does the reduction in the federal income tax rate per the TCJA affect Accumulated Deferred Income Tax (ADIT) balances?

A. Deferred income taxes are recorded to reflect higher income tax payments that will be paid to the Internal Revenue Service (IRS) when the tax benefits of current accelerated deductions reverse. As I have explained previously, for ratemaking purposes utilities use straight line or book depreciation to determine the depreciation charges that are included in cost of service. For income tax purposes, utilities can use accelerated tax depreciation methods in computing taxes payable to the IRS. These large early deductions result in reduced taxes payable during the early years of an asset's life followed by increases in taxes payable during later years of the asset's life. Over the asset's life, the same amount of asset deductions are used in computing the Company's income tax expense; it's just the timing of these deductions differs between ratemaking and tax reporting. The income tax effect of the book versus tax timing of the asset's deductions represent a deferred income tax expense. Deferred income taxes are computed at statutory tax rates, included in the Company's income tax expense and collected from customers as part of the utility's cost of service. The cumulative amount of deferred taxes collected are reflected in account 282 – Accumulated Deferred Income Taxes ("ADIT"), which is a reduction to the Company's rate base. As the timing of the accelerated tax deductions reverse, the Company will pay its deferred income taxes at 21%, even though it collected deferred income taxes from customers at a higher tax rate. The difference between the deferred income taxes that will be paid at 21% versus what has been collected from customers represents excess deferred income taxes ("EDIT") that the Company must refund to customers.

Q. How are the excess deferred taxes being refunded to customers?

A. The TCJA requires regulated public utilities subject to the normalization method of accounting to use the average rate assumption method ("ARAM") to reduce its excess deferred income tax reserve. Under this method, the excess deferred income tax reserve is reduced as the timing differences reverse over the remaining life of the asset and returned as an offset to the annual provision for deferred income taxes in the cost service calculation in rate proceedings. The Company is using ARAM to refund excess deferred taxes that have been recorded in account 282 – Accumulated Deferred Income Taxes and which have reduced the Company's rate base.

Q. Has the Company addressed the effects of the TCJA on 2018 in its filing?

A. Yes. The effects of the TCJA for 2018 are reflected in the tax calculation for 2018, the FTY in this case. The effects of the tax reductions are addressed in Mr. O'Brien's testimony (Statement No. 9).

C. CONSOLIDATED TAX ADJUSTMENT

Q. Was a Consolidated Tax Adjustment (CTA) included in the income tax expense claim?

A. No. With the passage of Act 40 of 2016, Pennsylvania joins a majority of states and the federal government in calculating a utility's federal income tax expense on a standalone basis, so that the recoverable tax expense is based on the utility's operations, and not on its affiliates. It is my understanding that Act 40, which added 66 Pa. C.S. §1301.1 to the Public Utility Code, prohibits including a CTA to the Company's income tax expense. However, Section 1301.1(b) also provides that if a consolidated tax expense differential accrues to the utility resulting from applying ratemaking methods employed prior the enactment of the Act, then 50% of the differential shall be used to support reliability or infrastructure construction related to the utility's rate base, with the other 50% used for general corporate purposes. I have included a calculation of a CTA adjustment that would have been computed under prior ratemaking methods in order to identify the differential; which as explained in the testimony of Mr. Morris in Statement No. 4, has been used to support reliability or infrastructure related capital investment. The federal tax rate of 21%, as provided in the TCJA, was used in the CTA calculation. See Exhibit MLS-2.

D. TAXES OTHER THAN INCOME TAXES:

Q. Please explain why there is no PA Capital Stock Tax adjustment.

A. The Pennsylvania capital stock tax has been phased out and thus there is no expense for the capital stock tax. Any change in this tax, or other taxes imposed by

Pennsylvania will be reflected in the State Tax Adjustment Surcharge between rate cases.

Q. Explain the PA gross receipts tax and property tax adjustments.

A. The PA utility gross receipts tax ("GRT") is levied at the rate of 59 mills (5.9%) on the Company's taxable gross receipts. This GRT rate is consistently applied throughout the test years. The public utility realty tax ("PURTA") and locally assessed real estate property taxes were based upon most recent assessments.

Q Does this conclude your direct testimony?

A. Yes, it does.

Item #	Subject Matter
DFR II-D-14	Debt Interest for Income Tax Calculation
DFR II-D-15	Schedule of Taxes Other than Income
DFR II-D-16	Schedule of Current and Deferred Tax Expense
DFR II-D-17	Schedule of Income Tax Refunds
DFR II-D-18	Prepaid and Deferred Income Tax Charges
DFR II-D-19	Federal Corporate Graduated Income Tax Rates
DFR II-D-20	Cost of Removal
DFR II-D-21	Income Tax Gain/Loss Carryovers
DFR II-D-22	Elim of Tax Savings by Payment of Interest on CWIP
DFR II-D-23	Consol. Tax Return Election - §1552
DFR II-D-24	Deferred Taxes Related to Depreciation
DFR II-D-25	Deferred Investment Tax Credits

Duquesne Light Company **EXHIBIT MLS-2**
Calculation of Consolidated Tax Adjustment
In Thousands (000)

	Taxable Income 2014	Taxable Income 2015	Taxable Income 2016	
Tax Loss Companies				
DQE HOLDINGS, LLC	(629)	(838)	(1,513)	
DUQUESNE LIGHT HOLDINGS, INC.	(70,917)	(67,970)	(62,715)	
DUQUESNE LIGHT COMPANY	-	-	(22,964)	
Total Tax Loss	(71,546)	(68,808)	(87,192)	
Tax Positive Companies				
DUQUESNE LIGHT COMPANY	92,932	116,214		
MONONGAHELA LIGHT AND POWER	817	889	837	
DUQUESNE FIBER COMPANY	1,095	360	541	
DES CORPORATE SERVICES, INC.	(4)	2	10	
DQE ENTERPRISES, INC.	59	0	259	
DQE CAPITAL CORPORATION	(3)	(4)	1	
DQE SYSTEMS, INC.	6,810	11,700	10,421	
Total Taxable Income	101,707	129,162	12,069	
Total Consolidated Income/(Loss)	30,161	60,353	(75,122)	
% of Total	91.37%	89.98%	0.00%	
Total Allocated Tax Loss	(65,373)	(61,911)	-	(42,428)
Distribution allocation				61.680% [a]
Loss allocated to Distribution				(26,170)
Federal Tax rate				21.0%
Consolidated Tax Adjustment				(5,496)

[a] Source: Mr. Gorman testimony, Statement #14, Jurisdictional Separation Study Exhibit 6-8A, JSS Factors - FedTax_Pres Distribution percentage

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3000124

Duquesne Light Company

Statement No. 12

DIRECT TESTIMONY OF PAUL R. MOUL

Dated: March 28, 2018

Duquesne Light Company
Direct Testimony of Paul R. Moul
Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used During Construction
B	Beta
B	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
DLH	Duquense Light Holdings, Inc.
DSIC	Distribution System Improvement Charge
EE&C	Energy Efficiency and Conservation Program
FOMC	Federal Open Market Committee
IGF	Internally Generated Funds
G	Growth rate
Lev	Leverage modification
LT	Long Term
M&M	Modigliani & Miller
MPL	Minimum pension liability
OCI	Other Comprehensive Income
POLR	Provider of last resort
PPUC	Pennsylvania Public Utility Commission
R	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
RTO	Regional Transmission Organizations

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
TCJA	Tax Cut and Jobs Act of 2017
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate rate of return that the Pennsylvania Public Utility Commission ("PPUC" or the "Commission") should recognize in the determination of the revenues that Duquesne Light Company ("Duquesne Light" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit PRM-1, which is a multi-page document divided into fourteen (14) schedules.

Q. Based upon your analysis, what is your conclusion concerning the appropriate cost of common equity and rate of return for the Company?

A. My conclusion is that the Company's rate of return on common equity is 10.95%, which is within the range of results of the cost of equity models and includes 0.20% in recognition of the strong performance by the Company in the area of management performance. In determining the rate of return on common equity, the Commission should consider the Company's system security, commitment to safety, infrastructure investment, and high quality of customer service. Moreover, as I will describe below, there will be more risk faced by the Company with the passage of the Tax Cut and Jobs Act of 2017 ("TCJA") signed into law on December 22, 2017. My analysis of the Company and its superior performance, as described in the testimony of Mr. C. James Davis and other Company witnesses should be recognized by the Commission in the rate of return. With this return, I have presented on page 1 of Schedule 1 the weighted average cost of capital, which is 8.06%. The Company's proposed rate of return is shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.49%	4.60%	2.09%
Common Equity	54.51%	10.95%	5.97%
Total	100.00%		8.06%

The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should, if adopted by the Commission, establish a compensatory level of return for the use of capital and provide the Company with the ability to attract capital which is essential to maintaining a safe, reliable and resilient network.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. Duquesne Light is wholly-owned subsidiary of Duquesne Light Holdings, Inc. ("DLH" or the "Parent Company"). The Company provides electric delivery service and provider of last resort ("POLR") service to approximately 590,000 customers in Allegheny and Beaver counties. In 2017, electric sales in MWh for Duquesne Light were comprised of approximately 31% to residential, 48% to commercial, 21% to industrial customers. The Company obtains the energy needs of its customers that use POLR service from third party suppliers.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for an electric utility, such as Duquesne Light. In this regard, I relied on four well-recognized measures of the cost of equity: The Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 10.95%, which is within the range of results of the cost of equity models and reflects 0.20% to recognize the strong performance of Duquesne in the area of management performance.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet increasing capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable (i.e. investment grade) credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. What factors have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of ten (10) electric companies. The criteria that I used to assemble the proxy group will be described later in my testimony. The companies in the electric proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Electric Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Electric Group. I have not measured separately the cost of equity for the individual companies within the Electric Group. By employing group average data, rather than individual Company's analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above, and revealed on page 2 of Schedule 1.

In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, reliance on a single method can provide

[1]Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table, derived from the model results presented on page 2 of Schedule 1, provides a summary of the indicated costs of equity using each of these approaches.

	Electric Group
DCF	10.76%
RP	11.25%
CAPM	11.30%
Comparable Earnings	12.35%

The returns that provide the range of the cost of equity are 10.76% to 11.30% using the market models. From these measures of the cost of equity, I recommend that the Company's rate of return on common equity be set at 10.95%, which is within the range of results reflected in the above table and also reflects 0.20% for strong management performance, as explained in the testimony of Mr. Davis. The testimony of Mr. Davis summarizes the many initiatives that the Company has undertaken, which have produced high quality service. In particular, Mr. Davis has shown that the Company ranks high in customer service and it has done so while maintaining an exceptional safety record. The Company should be granted an opportunity to earn a rate of return on common equity of at least 10.95%. I also believe my recommended cost of equity is appropriate in this case because it makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events that could occur during the rate effective period and the large construction projects underway.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Aside from its traditional responsibility to maintain reliability and comply with the mandates of the Commission, a different set of risks now exists for the electric delivery business in Pennsylvania. The potential expansion of distributed generation will have an increasing influence on the business of electric-delivery utilities. The obligation to serve represents a key risk factor for the local delivery of electricity. The risks facing the electric utilities are clearly different from those that existed in the past. Investors generally are risk-averse, and with increased uncertainty will require compensation for higher risk.

Q. Have these changes brought about increases in the risks facing electric utilities generally?

A. Electric utilities generally are faced with meaningful changes in the fundamentals that affect their operations, while retaining the obligation to serve under cost of service pricing that continues to dominate its business profile. The risk of distributed generation is a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of battery systems, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues. That is to say, the development of distributed generation and local alternative energy has the potential to displace delivery revenue that can impact the incumbent utility's financial profile. This risk is exacerbated by net metering rules that require offsets against distribution rates even though distribution costs may not be reduced as a result of the installation of distributed generation.

The cost to replace aging infrastructure and to enhance reliability and resiliency, and address cyber threats, also adds to the risk of electric delivery utilities, such as Duquesne Light, because these expenditures increase costs without any concomitant increase in revenues, except through regulatory approved rate increases, such as the Distribution System Improvement Charge ("DSIC"). The Company continues to make substantial investments to harden its system and expand its vegetation management practices to reduce the number and duration of storm-related outages experienced by customers. The DSIC contains a variety of limitations that will not eliminate the need for periodic rate cases to cover the significant new investment that is being made by Duquesne Light. Duquesne Light has also been engaged in an energy efficiency and conservation ("EE&C") program, pursuant the programs mandated by Act 129 of 2008, P.L. 1592 ("Act 129"). Reductions in revenues resulting from reductions in usage and demand the Company is required to achieve under its Commission-mandated EE&C program can be reflected only on a prospective basis in base rate cases, which can have an adverse impact on the Company between rate cases.

Q. Are there other specific risk issues facing the Company?

A. Yes. Energy deliveries to commercial and industrial customers, which represent 69% of the Company's energy deliveries, are usually thought to be of higher risk than to residential customers. Success in this segment of the Company's market is subject to the business cycle and pressures from alternative providers. Moreover, external factors also can influence deliveries to these customers, which face competitive pressure on their own operations from other facilities outside the utility's service territory.

In addition, significant efforts to encourage conservation pursuant to the requirements of Act 129 create a risk that Duquesne Light's distribution revenues will likely decline between base rate cases.

Q. You indicated previously that the recent federal income tax law changes will add to the Company's risk. Please explain.

A. There are several major financial consequences that flow from the recent changes in the federal income tax law that will negatively affect the Company. First, a lower federal income tax rate (21% versus 35%) will lower the Company's pre-tax interest coverage and, therefore, will reduce its credit quality and increase risk. For example, page 1 of Schedule 1 shows that with a 21% marginal federal corporate income tax rate, the Company's pre-tax interest coverage will be 4.93 times at its proposed distribution rates. Under the pre-2019 marginal federal corporate income tax rate of 35%, the Company's pre-tax interest coverage would have been 5.81 times. That difference in coverage ratios does not reflect other changes driven by the tax law that may also impact the Company's financial condition and credit quality, such as the flow-back of "excess" accumulated deferred income taxes ("ADIT"). Second, with a lower marginal federal corporate income tax rate, the variability of the Company's returns will increase, which also increases its business risk. When the federal corporate income tax rate was 35%, investors only needed to absorb 65% of any changes in revenues and expenses. This happens because the Company had a tax benefit equal to 35% of any increase in deductible expenses or 35% of any decrease in taxable revenue. At the current federal corporate income tax rate, the tax benefit is reduced to 21% and, therefore, investors will need to absorb 79% of any increase in expenses or reduction in revenue. As a result, lower federal income taxes will make investor returns more volatile than before the tax rate change occurred, and volatility translates into increased business risk to the Company. Third, utilities will require more investor-supplied capital to fund construction programs because the level of deferred taxes will decline, the new tax law eliminates bonus depreciation, and "excess" ADIT created by the reduction in the federal corporate income tax rate will have to be flowed back to customers. This will also impact another credit metric that is important to capital-intensive industries such as electric utilities, namely, internally generated funds as a percentage of construction expenditures. This percentage will decline because of the new lower income tax rate. In response to these financial challenges caused by the new lower federal corporate income tax rate, there may be the need to reduce the percentage of debt in a utility's capital structure to respond to higher business risk and weaker credit quality measures. Indeed, the effects of TCJA have prompted Moody's Investor Services to place some utilities on credit watch with a negative outlook. As noted in the testimony of Mr. Milligan, the Company is proposing to increase its common equity ratio modestly in response to the TCJA tax rate change.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory and to meet growth. Over the next five years (i.e., 2018 through 2022), the Company's total capital expenditures are expected to be approximately $1,519.3 million. These expenditures will represent approximately 52% ($1,519.3 million ÷ $2,941.7 million) of the net utility plant at December 31, 2017. A fair rate of return for the Company represents a key to a financial profile that will provide the Company with the ability to raise the capital, in all market conditions to meet its needs, and to satisfy investor requirements. In the situation where additional capital is required, as shown by the construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. This is especially important for Duquesne Light due to its smaller size and the magnitude of its construction program.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared Duquesne Light to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Electric Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of

Schedule 4.

Q. What criteria did you employ to assemble the Electric Group?

A. The Electric Group companies have the following common characteristics: (i) their stock is traded on the New York Stock Exchange, (ii) they are listed in the "Electric Utility (East)" section of <u>The Value Line Investment Survey</u>, (iii) they are not currently the target of a publicly-announced merger or acquisition and (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony. It would be inappropriate to include a company that is a target of a takeover in a proxy group because the stock price of that company usually does not reflect its underlying fundamentals. My Electric Group obtained from the <u>Value Line Investment Survey</u> consists of the following companies: AVANGRID, Inc., Consolidated Edison, Dominion Energy, Duke Energy, Eversource Energy, Exelon Corp., FirstEnergy Corp., NextEra Energy, PPL Corp., and Public Service Enterprise Group.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for Duquesne Light, the Electric Group, and the S&P Public Utilities?

A. For Duquesne Light, its Long Term ("LT") issuer rating is A3 from Moody's Investors Service ("Moody's") and the corporate credit rating ("CCR") is BBB from Standard & Poor's Corporation ("S&P"). The LT issuer rating by Moody's and the CCR designation by S&P focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The testimony of Mr. James Milligan, the Company's Assistant Treasurer, provides further detail on the Company's credit ratings. For the Electric Group, the average LT issuer rating is Baa1 from Moody's and the average CCR is BBB+ from S&P. For the S&P Public Utilities, the average composite rating is A3 by Moody's and BBB+ by S&P. Many of the financial indicators that I will subsequently discuss are considered during the rating process. In this regard, the Company's credit quality is fairly similar to the Electric Group (e.g. Duquesne's Moody's rating is one notch higher than the Electric Group and its S&P rating is one notch lower).

Q. How do the financial data compare for Duquesne Light, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2012-2016. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, Duquesne Light is much smaller than the average size of the Electric Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. In addition, Duquesne Light serves a concentrated geographic area, and in particular, an urban area that is often more costly to service. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for Duquesne Light.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

There are no market ratios available for Duquesne Light because the Company's stock is not traded. The five-year average price-earnings multiple for the Electric Group was slightly higher than that of the S&P Public Utilities. The five-year average dividend yield was slightly higher for the Electric Group, as compared to the S&P Public Utilities. The average market-to-book ratio for the Electric Group was fairly similar to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm

[2]For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 53.0% for Duquesne Light, 48.2% for the Electric Group, and 44.3% for the S&P Public Utilities. The common equity ratio in 2016 was 46.2% for the Electric Group and reflected a range of common equity ratios from 23.4% to 75.7%. The common equity ratio proposed by Duquesne Light in this case of 54.51%, is within the range of common equity ratios for the Electric Group.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.144 (1.6% ÷ 11.1%) for Duquesne Light, 0.046 (0.4% ÷ 8.7%) for the Electric Group, and 0.022 (0.2% ÷ 9.2%) for the S&P Public Utilities. The earnings variability for Duquesne Light was significantly higher than the Electric Group and the S&P Public Utilities, indicating that the Company has higher risk. And, as I indicated previously, the recent changes in the federal income tax law will likely make these variability statistics higher in the future.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income taxes).[3] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin. The five-year average operating ratios were 70.1% for Duquesne Light, 77.8% for the Electric Group, and 80.4% for the S&P Public Utilities. The operating risk for Duquesne Light is below that for to the Electric Group, and the S&P Public Utilities, thus indicating lower risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC") was 5.79 times for Duquesne Light, 3.56 times for the Electric Group, and 3.15 times for the S&P Public Utilities. The higher interest coverage for Duquesne Light can be traced to its lower proportion of debt in its capital structure. Again, these indicators will decline prospectively with the implementation of the pending federal income tax changes.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings

[3]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for Duquesne Light, the Electric Group, and the S&P Public Utilities. Prospectively, the effective income tax rate will decline and quality of earnings will suffer.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 84.3% for Duquesne Light, 81.3% for the Electric Group, and 79.5% for the S&P Public Utilities. The IGF percentages were fairly similar for Duquesne, the Electric Group, and the S&P Public Utilities. As noted previously, the IGF to construction expenditures will decline with the new lower federal income tax rate.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of .66 as the average for the Electric Group (see page 2 of Schedule

[4]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

3), and .75 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

Q. Please summarize your risk evaluation of the Company and the Electric Group.

A. The risk of Duquesne Light parallels that of the Electric Group in certain respects. However, Duquesne Light is much smaller than the average size of the Electric Group and its earnings are much more variable. The Company's lower financial risk (i.e., higher common equity ratio) provides a partial offset to these high-risk factors. Lower risk indicators for the Company are its operating ratio and interest coverages. Its quality of earnings and IGF to construction has been similar to the Electric Group. On balance, the risk factors average out, indicating that the cost of equity for the Electric Group would provide a reasonable basis for measuring the Company's cost of equity, provided that the rate of return determination reflects the Companies' common equity ratio. As such, the results from the Electric Group provide a reasonable measure of the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for Duquesne Light.

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for Duquesne Light, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed. This procedure is consistent with the procedures used by the Commission in prior rate cases.

Q. Does Schedule 5 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 5 presents Duquesne Light's capitalization and related capital structure at December 31, 2017, the end of the historic test year. Also shown on Schedule 5 is the Duquesne Light's estimated capital structure at December 31, 2018, which is the end of the future test year, and at December 31, 2019, which is the end of the fully projected future test year. During the future test year, the changes in the Company's capital structure are projected to include: (i) the call of four issues of pollution control debt totaling $109.905 million; (ii) the issuance of two traches of long-term debt in the amount of $185 million that occurred on February 1, 2018, and (iii) the Company's projection of retained earnings growth.

Also reflected on Schedule 5 are several adjustments to the capital structure. The first adjustment is related to the call premiums on the early redemption or refunding of high cost long-term debt. The second adjustment relates to the elimination of accumulated Other Comprehensive Income ("OCI").

Q. Please describe the first adjustment.

A. I have adjusted the principal amounts of long-term debt to exclude the amounts used to finance premiums on the early redemption of high cost long-term debt. To do otherwise would deny Duquesne Light the full return on the premiums paid to redeem this high cost capital since additional amounts of capital were issued to pay the call premiums. The amounts issued to finance the call premiums do not increase the Company's rate base. That is to say, no additional rate base was created through additional debt that was necessary to finance these transactions, and therefore an adjustment is required to provide the return necessary to service the additional capital. Hence, Duquesne Light's long-term debt amounts must be adjusted for this disparity in order that the return necessary to service the capitalization is produced from rate base investment times the overall rate of return.

This adjustment is equitable since customers receive the cost savings resulting from these refinancing in the form of a lower overall rate of return, and Duquesne Light recovers all costs incurred in providing these benefits to the customers. To accomplish these savings, the Company paid the debt holders a premium for surrendering its securities prior to maturity. These premiums represented an investment made by Duquesne Light to reduce its overall cost of capital. Since the reduced interest costs are reflected in the lower cost of capital to ratepayers, it is appropriate that the Company recover the costs incurred to produce these savings. This includes both a return of and return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides a return on the premium as a part of the embedded cost rates of capital.

Q. Please explain the second adjustment.

A. The accumulated OCI must be eliminated from the capital structure for ratesetting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI must be excluded from the common equity because it does not represent funds that the Company has used to finance its rate base.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratemaking is prospective, the rate of return should reflect known changes that will occur during the course of the fully projected future test year, at a minimum, and should consider conditions that will exist during the period of time the proposed rates will be effective. As a result, I will adopt the Company's fully projected future test year-end capital structure ratios of 45.49% long-term debt, and 54.51% common equity. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect. Short-term debt has been excluded from these ratios because the Commission's approved practice is to assign short-term debt to CWIP in the calculation of AFUDC. Hence, the cost of short-term debt is capitalized through AFUDC and plays no role in setting base rates. For example, the short-term debt for the fully projected future test year shown on Schedule 5 (i.e., $123 million) is less than the associated CWIP balances of $217.112 million at December 31, 2019. This means that all short-term debt is being used by the Company to finance CWIP.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the debt portion of Duquesne Light's capital structure?

A. Consistency with the capital structure ratios for the Company requires that the embedded cost rates of Duquesne Light's senior securities must also be employed. This procedure is consistent with the ratesetting procedures used by the Commission in prior Duquesne Light rate cases. The determination of the cost of debt is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, the actual embedded cost rate of long-term debt was 4.73% at December 31, 2017. By December 31, 2019, the embedded debt cost rate is estimated to be 4.60%, as shown on page 3 of Schedule 6. The details leading to the development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, are shown on page 4 of Schedule 6. The cost rate, or yield to maturity ("ytm"), used on page 4 of Schedule 6 is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

I will adopt the 4.60% embedded cost of long-term debt at December 31, 2019, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 45.49% long-term debt ratio. In my calculation of the embedded cost of long-term debt, I have recognized the costs associated with the Company's early redemption of high cost debt. As previously explained, it is necessary to compensate Duquesne Light for the costs incurred to lower the embedded debt cost rate which reduces the cost of capital charged to ratepayers. The amortization of gains on long-term debt has also been reflected as part of these costs during the historic test year. Subsequent thereto, the amortization of the gains ended.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among Duquesne Light, the Electric Group, and the

S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group and arrived at a cost of equity of 10.95% for Duquesne Light, which includes 20% in recognition of strong management performance.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe the Discounted Cash Flow model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on page 2 of Schedule 1 for the Electric Group. The DCF return is 10.76%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by dividend receipts. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended January 2018, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e.,

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended January 2018 the average dividend yield was 3.72% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 3.65% and 3.67%, respectively. The trend has been toward higher yields. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.65% for the Electric Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Electric Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds eleven basis points to the six-month average historical yield, thus producing the 3.76% adjusted dividend yield for the Electric Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts, which are those used by investors when pricing common stocks.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner.

Q. How did you determine an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What data for the Electric Group have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 8 and 9. In this regard, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks. Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So, with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio. The historical growth rates were taken from the Value Line publication that provides this data. As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, assigning significant weight to historical performance results in double counting of the historical data. While history cannot be ignored, it is already factored into the analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance. As shown on Schedule 8, the historical growth of earnings per share was in the range of -0.06% to 3.33% for the Electric

Group. Negative growth that occurred in the past is not reflective of investor expectations for the future that encompass positive returns.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes. The constant form of the DCF assumes an infinite stream of cash flows, but investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication suggests that there is no market for this information, because investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Zacks, Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 9 for the Electric Group.

Q. What are the projected growth rates published by the sources you discussed?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Electric Group are 4.83% by IBES/First Call, 5.04% by Zacks, 6.11% by Morningstar, 5.13% by SNL and 6.06%% by Value Line. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What other factors did you consider in developing a growth rate?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[6] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, SNL, and <u>Value Line</u>, represent a reasonable assessment of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 4.83% to 6.11%. Although the DCF growth rates

---

[6] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.75% is a reasonable estimate of investor expected growth within the array of earnings per share growth rates shown by the analysts' forecasts. Indeed, my 5.75% growth rate is obtained from the analysts' growth forecasts that cover a five-year period, which are the growth rates that investors employ for DCF purposes. Improved economic growth argues for a DCF growth rate near the high end of the range. Economic growth is expected to accelerate with the implementation of the new federal corporate income tax provisions.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Electric Group, those average capital structure ratios are 42.95% long-term debt, 0.06% preferred stock, and 56.99% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. Where a firm's capitalization as measured by its stock price diverges from its book value capitalization, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value. A leverage adjustment accounts for this difference between market value and book value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes) the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Electric Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the rate setting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the rate setting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M," provides a return of 7.40% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. In this regard, according to the Barron's issue of February 26, 2018, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 1.99 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 4.71 times book value, and the Dow Jones Industrial index was at 4.35 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.40%, which is the return for the Electric Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 3.36% compensation for having a 54.49% debt ratio, plus 0.00% for having a 0.08% preferred stock ratio. The sum of the parts is 10.76% (7.40% + 3.36% + 0.00%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.76% dividend yield, the 5.75% growth rate, and the 1.25% for the leverage adjustment in order to arrive at the same 10.76% (3.76% + 5.75% + 1.25%) return. I know of no means to mathematically solve for the 1.25% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.25% adjustment is merely a convenient way to compare the 10.76% return computed directly with the Modigliani & Miller formulas to the 9.51% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF -- see page 1 of Schedule 7) based on a market value capital structure. A 9.51% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. What does your DCF analysis show?

A. As explained previously, I have utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the rate setting process rather than the market value equity ratio related to the price of stock.

	D_1/P_0	+	g	+	$lev.$	=	k
Electric Group	3.76%	+	5.75%	+	1.25%	=	10.76%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity. Moreover, the DCF results shown above are representative of investor expected returns for relatively large companies. Duquesne Light is a much smaller company, which makes it riskier. Therefore, the DCF results for the Electric Group understate the return on equity for Duquesne Light. In the current environment of rising interest rates, the DCF method tends to be less responsive (i.e., there is a lag) to changes in those rates. As such, other methods for measuring the cost of equity, e.g. Risk Premium and CAPM, should be emphasized because they respond promptly to change in interest rates.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the risk premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.25%.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 4.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data is shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 11. For the twelve months ended January 2018, the average monthly yield on Moody's index of A-rated public utility bonds was 3.98%. For the six and three-month periods ended January 2018, the yields were 3.85% and 3.83%, respectively. During the twelve-months ended January 2018, the range of the yields on A-rated public utility bonds was 3.79% to 4.23%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.09% on a twelve-month average basis, 1.04% on a six-month average basis, and 1.01% on a three-month average basis. From these averages, 1.00% represents a conservative spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on February 1, 2018, and a yield spread of 1.00%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2018	First	3.8%	4.5%	3.0%	1.00%	4.00%
2018	Second	4.0%	4.7%	3.1%	1.00%	4.10%
2018	Third	4.2%	4.9%	3.3%	1.00%	4.30%
2018	Fourth	4.3%	5.0%	3.4%	1.00%	4.40%
2019	First	4.5%	5.2%	3.5%	1.00%	4.50%
2019	Second	4.6%	5.4%	3.6%	1.00%	4.60%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2017 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2019-2023	5.1%	6.0%	4.1%
2024-2028	5.4%	6.2%	4.3%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. By focusing more on these forecasts, a 4.75% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. In reaching my conclusion as to a prospectively yield on A-rated public utility debt, I have considered the data relied upon by investors.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2017 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 12.

Common Equity Risk Premiums	
Low Interest Rates	7.08%
Average Across All Interest Rates	5.64%
High Interest Rates	4.18%

Based on my analysis of the historical data, the equity risk premium was 7.08% when the marginal cost of long-term government bonds was low (i.e., 2.96%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.22% on average during periods of high interest rates) the spread narrowed to 4.18%. Over the entire spectrum of interest rates, the equity risk premium was 5.64% when the average government bond yield was 5.07%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.08% premium related to periods of low interest rates and the 5.64% premium related to average interest rates across all levels.

Q. What common equity cost rate did you determine based on your risk premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

$$i + RP = k$$

$$\text{Electric Group} \quad 4.75\% + 6.50\% = 11.25\%$$

Indeed, in an environment of rising interest rates, the Risk Premium model provides a direct reflection of the cost of equity that captures higher interest rates.

CAPITAL ASSET PRICING MODEL

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 11.20%. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.66 for the Electric Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the rate setting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[7] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

Where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.41 for the Electric Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada" who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 0.80 for the book value capital structure of the Electric Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.80 for the Electric Group.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended January 2018, the average yield on 30-year Treasury bonds was 2.88%. For the six- and three-months ended January 2018, the yields on 30-year Treasury bonds were 2.82% and 2.82%, respectively. During the twelve-months ended January 2018, the range of the yields on 30-year

[7] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp. 435-452.

Treasury bonds was 2.77% to 3.08%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). Essentially, low interest rates were the product of the policy of the Federal Open Market Committee ("FOMC") in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC ended its bond purchasing program at its policy meeting on October 29, 2014. At its December 16, 2015 meeting, the FOMC increased the federal funds rate range by 0.25 percentage points. On December 14, 2016, the FOMC acted again by raising the Fed Funds rate by one-quarter percentage point. The FOMC also used this occasion to express a more aggressive approach to future increases in interest rates. In addition, the Fed has indicated that it will reduce the size of its balance sheet. FOMC increased the fed funds rate on three occasions in 2017 (i.e., March 15, 2017, June 14, 2017 and December 13, 2017) by one-quarter percentage point each. The Wall Street Journal has also reported that three one-quarter percentage point rate increases are anticipated for 2018 and two one-quarter percentage point rate increases will likely follow in each of the years 2019 and 2020. This buttresses the prospect that higher interest rates are on the horizon.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on February 1, 2018 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.0% to 3.6% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.1% from 2019 through 2023 and 4.3% from 2024 to 2028. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 3.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 11.97% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.96% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 11.96% (11.97% + 11.95% = 23.92% ÷ 2) and the average yield on long-term government bonds of 4.02% (2.96% + 5.07% = 8.03% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 7.94% (11.96% - 4.02%) based on historical data, as shown on page 2 of Schedule 13. For the forecast returns, I calculated a 12.13% DCF return for the S&P 500. Normally, I would also include the Value Line forecast data as part of the market premium calculation. But in this instance, the Value Line result of 7.64% is clearly anomalous. I say this because those forecasts are established by Value Line in a hypothesized economic environment 3 to 5 year hence. In that hypothesized economy, real GDP growth is approximately 2.5%. With the recent passage of the new federal corporate income tax law, GDP is expected to increase from that level. As such, I have suspended use of the Value Line forecast for the purpose of this case. With the forecast return of 12.13%, I calculated a market premium of 8.38% (12.13% - 3.75%) using the S&P 500 forecast data. Indeed, this forecast market premium is more in-line with historical evidence. The market premium applicable to the CAPM derived from these sources equals 8.16% (8.38% + 7.94% = 16.32% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October

15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the capitalization Duquesne Light is just $2,239.4 million as compared to the Electric Group's average capitalization of $42,547.1 million. For my CAPM analysis, I have adopted a mid-cap adjustment of 1.02%, as shown on page 3 of Schedule 13.

Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.80 for the Electric Group, the 8.16% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+	β	x (	$Rm-Rf$)	+	size	=	k
Electric Group	3.75%	+	0.80	x (	8.16%)	+	1.02%	=	11.30%

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risks characteristics would need to realize in order to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the <u>Bluefield</u> case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 11.5% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by <u>Value Line</u> is 13.2% also using values less than 20%, as provided on page 2 of Schedule 15. Using the average of these data my Comparable Earnings result is 12.35%, as shown on page 2 of Schedule 1.

<u>CONCLUSION</u>

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 10.95% for Duquesne Light, which includes 0.20% in recognition of the

Company's strong management performance. My cost of equity recommendation is obtained from a range of results (i.e., 10.76% to 11.25%) and should be considered in the context of the Company's risk characteristics, as well as the general condition of the capital markets, and the strong performance of the Company's management. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

Exhibit PRM-1

DUQUESNE LIGHT COMPANY

EXHIBIT

TO ACCOMPANY

THE DIRECT TESTIMONY

OF

PAUL R. MOUL

CONCERNING
RATE OF RETURN

Exhibit PRM-1

Duquesne Light Company
Index of Schedules

Duquesne Light Company
Proposed Rate of Return
Estimated at December 31, 2019

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.49%	4.60%	2.09%
Common Equity	54.51%	10.95%	5.97%
Total	100.00%		8.06%

Indicated levels of fixed charge coverage assuming that
the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a
28.8921% composite federal and state income tax rate
(10.49% ÷ 2.09%) 5.02 x

Post-tax coverage of interest expense
(8.06% ÷ 2.09%) 3.86 x

Duquesne Light Company

Cost of Equity
as of January 31, 2018

Discounted Cash Flow (DCF)	D_1/P_0 [1]	+	*g* [2]	+	*lev.* [3]	=	*k*				
Electric Group	3.76%	+	5.75%	+	1.25%	=	10.76%				
Risk Premium (RP)	*I* [4]	+	*RP* [5]	=	*k*						
Electric Group	4.75%	+	6.50%	=	11.25%						
Capital Asset Pricing Model (CAPM)	*Rf* [6]	+	*ß* [7]	x (	*Rm-Rf* [8]	) +	*size* [9]	=	*k*		
Electric Group	3.75%	+	0.80	x (	8.16%	) +	1.02%	=	11.30%		
Comparable Earnings (CE)	***Historical*** [10]		***Forecast*** [10]		**Average**						
Comparable Earnings Group	11.5%		13.2%		12.35%						

References
(1) Schedule 08 page 1
(2) Schedule 10 page 1
(3) Schedule 11 page 1
(4) A-rated public utility bond yield comprised of a 3.75% risk-free rate of return (Schedule 14 page 2) and a yield spread of 1.00% (Schedule 12 page 3)
(5) Schedule 13 page 1
(6) Schedule 14 pages 1 & 2
(7) Schedule 11 page 1
(8) Schedule 14 page 2
(9) Schedule 14 page 3
(10) Schedule 15 page 2

Duquesne Light Company
Capitalization and Financial Statistics
2012-2016, Inclusive

	2016	2015	2014	2013	2012	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 2,239 4	$ 2,191 3	$ 2,130 9	$ 2,083 6	$ 1,950 1	
Short-Term Debt	$ -	$ -	$ -	$ -	$ 20 0	
Total Capital	$ 2,239 4	$ 2,191 3	$ 2,130 9	$ 2,083 6	$ 1,970 1	
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	45 9%	46 8%	42 2%	41 7%	39.5%	43 2%
Preferred Stock	1 5%	1 5%	5 1%	5 2%	5.5%	3 8%
Common Equity	52 6%	51.7%	52 7%	53.1%	55.0%	53 0%
	100 0%	100 0%	100 0%	100.0%	100.0%	100 0%
Based on Total Capital						
Total Debt, incl Short Term	45 9%	46 8%	42 2%	41 7%	40.1%	43 3%
Preferred Stock	1 5%	1.5%	5 1%	5.2%	5 5%	3 8%
Common Equity	52.6%	51 7%	52 7%	53 1%	54 4%	52 9%
	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Rate of Return on Book Common Equity	10 2%	10 4%	9 9%	11 3%	13 8%	11 1%
Operating Ratio (1)	73 6%	72 8%	71 5%	66 9%	65 7%	70 1%
Coverage incl AFUDC (2)						
Pre-tax All Interest Charges	5 03 x	4 59 x	5 75 x	6 37 x	7 21 x	5 79 x
Post-tax: All Interest Charges	3 43 x	3 12 x	3 72 x	4 11 x	4 69 x	3 81 x
Overall Coverage All Int & Pfd Div	3 34 x	2 89 x	3 25 x	3 58 x	4 08 x	3 43 x
Coverage excl AFUDC (3)						
Pre-tax All Interest Charges	5 03 x	4 59 x	5 75 x	6 37 x	7 21 x	5 79 x
Post-tax All Interest Charges	3 43 x	3 12 x	3 72 x	4 11 x	4.69 x	3 81 x
Overall Coverage All Int & Pfd Div	3 34 x	2 89 x	3.25 x	3.58 x	4.08 x	3.43 x
Quality of Earnings & Cash Flow						
AFC/Income Avail for Common Equity	0 0%	0 0%	0 0%	0.0%	0 0%	0 0%
Effective Income Tax Rate	39 7%	41 0%	42 7%	42 1%	40.7%	41 2%
Internal Cash Generation/Construction (4)	98 6%	77 1%	90 7%	71.3%	83.7%	84.3%
Gross Cash Flow/ Avg. Total Debt(5)	33 1%	29 8%	32 5%	30.6%	41.9%	33 6%
Gross Cash Flow Interest Coverage(6)	7 94 x	5 88 x	7 76 x	7 00 x	9 15 x	7.55 x
Common Dividend Coverage (7)	3 72 x	3 04 x	3 03 x	2 75 x	1 95 x	2 90 x

See Page 2 for Notes

Duquesne Light Company.
Capitalization and Financial Statistics
2012-2016, Inclusive

Notes:

(1) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(2) Coverage calculations represent the number of times available earnings including AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(3) Coverage calculations represent the number of times available earnings excluding AFUDC (allowance for funds used during construction), as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Company provided data

Electric Group
Capitalization and Financial Statistics (1)
2012-2016, Inclusive

	2016	2015	2014 (Millions of Dollars)	2013	2012	Average
Amount of Capital Employed						
Permanent Capital	$ 41,179 4	$ 38,011 3	$ 36,288 8	$ 33,192 4	$ 31,899 3	
Short-Term Debt	$ 1,367.7	$ 1,430 2	$ 1,191 3	$ 1,050 7	$ 963 3	
Total Capital	$ 42,547 1	$ 39,441 5	$ 37,480 1	$ 34,243 1	$ 32,862 6	
Market-Based Financial Ratios						
Price-Earnings Multiple	20 x	19 x	24 x	20 x	26 x	22 x
Market/Book Ratio	178 0%	167 2%	176 7%	164 8%	163 1%	170 0%
Dividend Yield	3 9%	3 5%	3 8%	4 3%	4 5%	4 0%
Dividend Payout Ratio	76 6%	60 0%	93 3%	82 9%	114 2%	85 4%
Capital Structure Ratios						
Based on Permanent Captial						
Long-Term Debt	52 8%	49 9%	49 1%	52 3%	52 2%	51 2%
Preferred Stock	1 0%	0 7%	0 6%	0 3%	0 3%	0 6%
Common Equity (2)	46 2%	49 4%	50 4%	47 5%	47.5%	48 2%
	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Based on Total Capital						
Total Debt incl Short Term	54 2%	51 6%	50 4%	53 9%	53 7%	52 8%
Preferred Stock	1 0%	0 7%	0 6%	0 2%	0 3%	0 5%
Common Equity (2)	44 9%	47 8%	49 0%	45 8%	46 0%	46 7%
	100.0%	100.0%	100 0%	100 0%	100.0%	100 0%
Rate of Return on Book Common Equity (2)	9 0%	9 2%	8 5%	8 7%	8 2%	8 7%
Operating Ratio (3)	75 5%	76 6%	79 3%	78 2%	79 4%	77 8%
Coverage incl AFUDC (4)						
Pre-tax All Interest Charges	3 85 x	3.89 x	3 65 x	3 52 x	3 23 x	3 63 x
Post-tax All Interest Charges	2 92 x	2 95 x	2 72 x	2 67 x	2 49 x	2 75 x
Overall Coverage All Int & Pfd Div	2 92 x	2 95 x	2 72 x	2 67 x	2 49 x	2 75 x
Coverage excl AFUDC (4)						
Pre-tax All Interest Charges	3.76 x	3 82 x	3.59 x	3 47 x	3 16 x	3 56 x
Post-tax All Interest Charges	2 83 x	2 87 x	2 66 x	2 61 x	2 42 x	2 68 x
Overall Coverage All Int & Pfd Div	2 83 x	2 87 x	2 66 x	2 61 x	2 42 x	2 68 x
Quality of Earnings & Cash Flow						
AFC/Income Avail for Common Equity	5 0%	5 8%	8.4%	4 8%	5 7%	5 9%
Effective Income Tax Rate	32 8%	30 6%	27.3%	32 1%	32 8%	31.1%
Internal Cash Generation/Construction (5)	79 1%	81 3%	92 8%	80 6%	72 6%	81 3%
Gross Cash Flow/ Avg Total Debt (6)	22 2%	22.5%	25 2%	20 6%	22 4%	22 6%
Gross Cash Flow Interest Coverage (7)	6 00 x	5 78 x	5.79 x	5 42 x	6 31 x	5 86 x
Common Dividend Coverage (8)	4 27 x	4 13 x	4 33 x	3 70 x	3 55 x	4 00 x

See Page 2 for Notes

Electric Group
Capitalization and Financial Statistics
2012-2016, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Electric Group includes companies that: (i) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, and (iv) are not engaged in the construction of a nuclear generating plant or have not recently cancelled the construction of a nuclear generating plant.

		Corporate Credit Ratings		Stock	S&P Stock	Value Line
Ticker	Company	Moody's	S&P	Traded	Ranking	Beta
AGR	Avangrid, Inc.	Baa1	BBB+	NYSE	NR	NMF
ED	Consol. Edison	A3	A-	NYSE	B+	0 50
D	Dominion Energy	Baa2	BBB+	NYSE	B	0.65
DUK	Duke Energy	Baa1	A-	NYSE	B	0.60
ES	Eversource Energy	Baa1	A	NYSE	A	0.65
EXC	Exelon Corp.	Baa2	BBB	NYSE	B	0.70
FE	FirstEnergy Corp	Baa3	BBB-	NYSE	B	0.70
NEE	NextEra Energy	Baa1	A-	NYSE	A	0.65
PPL	PPL Corp.	Baa2	A-	NYSE	B	0.75
PEG	Public Serv Enterprise	Baa1	BBB+	NYSE	B+	0.70
	Average	Baa1	BBB+		B+	0.66

Source of Information: Standard & Poor's Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics (1)
2012-2016, Inclusive

	2016	2015	2014 (Millions of Dollars)	2013	2012	Average
Amount of Capital Employed						
Permanent Capital	$ 31,133 4	$ 28,468 3	$ 27,468.3	$ 25,958 6	$ 25,040 3	
Short-Term Debt	$ 1,113 4	$ 930 9	$ 963 9	$ 764 3	$ 659 0	
Total Capital	$ 32,246 8	$ 29,399 2	$ 28,432 2	$ 26,722 9	$ 25,699 3	
Market-Based Financial Ratios						
Price-Earnings Multiple	21 x	20 x	20 x	19 x	16 x	19 x
Market/Book Ratio	191 5%	179 3%	179 1%	164 4%	155 6%	174 0%
Dividend Yield	3 6%	3 7%	3 6%	3.9%	4 1%	3 8%
Dividend Payout Ratio	75 0%	70 0%	73 2%	73 3%	64 2%	71 1%
Capital Structure Ratios						
Based on Permanent Captial						
Long-Term Debt	56 7%	54 9%	53.3%	53 3%	53 7%	54 4%
Preferred Stock	1 8%	1 5%	1 3%	1 1%	1 0%	1 3%
Common Equity (2)	41 5%	43 6%	45.4%	45 7%	45 3%	44 3%
	100 0%	100 0%	100 0%	100 0%	100 0%	100 0%
Based on Total Capital						
Total Debt incl Short Term	58.3%	56 3%	55 0%	54 7%	54 9%	55 8%
Preferred Stock	1 8%	1 5%	1 3%	1.0%	1 0%	1 3%
Common Equity (2)	39 9%	42 2%	43.7%	44 3%	44 2%	42 9%
	100 0%	100 0%	100.0%	100.0%	100 0%	100 0%
Rate of Return on Book Common Equity (2)	9 0%	9 2%	9.6%	9.0%	9 3%	9 2%
Operating Ratio (3)	78 8%	80 4%	81 2%	80 7%	80 7%	80 4%
Coverage incl AFUDC (4)						
Pre-tax All Interest Charges	3 15 x	3 41 x	3 56 x	3 22 x	2 90 x	3 25 x
Post-tax All Interest Charges	2 53 x	2 65 x	2.71 x	2 48 x	2 35 x	2 54 x
Overall Coverage All Int & Pfd Div	2.50 x	2 62 x	2.67 x	2 45 x	2 31 x	2 51 x
Coverage excl AFUDC (4)						
Pre-tax All Interest Charges	3 05 x	3 31 x	3 46 x	3 13 x	2 80 x	3.15 x
Post-tax All Interest Charges	2 43 x	2 55 x	2.62 x	2 39 x	2 25 x	2 45 x
Overall Coverage All Int & Pfd Div	2 40 x	2 52 x	2 58 x	2 36 x	2 21 x	2 41 x
Quality of Earnings & Cash Flow						
AFC/Income Avail for Common Equity	6.4%	6 0%	7.1%	6 4%	7.0%	6 6%
Effective Income Tax Rate	28.1%	31 5%	28.6%	33 2%	30 7%	30.4%
Internal Cash Generation/Construction (5)	78.7%	70 6%	88.7%	83 2%	76 5%	79.5%
Gross Cash Flow/ Avg Total Debt (6)	20 7%	20 0%	22 8%	22 4%	21 8%	21.5%
Gross Cash Flow Interest Coverage (7)	5 54 x	5 39 x	5 66 x	5 46 x	5 44 x	5 50 x
Common Dividend Coverage (8)	5 41 x	4 23 x	4 80 x	4.41 x	4 31 x	4 63 x

See Page 2 for Notes

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2012-2016, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities

	Ticker	Credit Rating [1] Moody's	Credit Rating [1] S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
AGL Resources Inc.	GAS	A2	BBB+	NYSE	A	0.60
Ameren Corporation	AEE	Baa1	BBB+	NYSE	B	0.75
American Electric Power	AEP	Baa1	BBB	NYSE	B	0.70
CMS Energy	CMS	A3	BBB	NYSE	B	0.75
CenterPoint Energy	CNP	A3	A-	NYSE	B	0.85
Consolidated Edison	ED	A2	A-	NYSE	B+	0.60
DTE Energy Co.	DTE	A2	BBB+	NYSE	B+	0.75
Dominion Resources	D	A2	A-	NYSE	B+	0.70
Duke Energy	DUK	A1	BBB+	NYSE	B	0.65
Edison Int'l	EIX	A2	BBB+	NYSE	B	0.70
Entergy Corp.	ETR	Baa1	BBB	NYSE	A	0.70
EQT Corp.	EQT	Baa3	BBB	NYSE	B+	1.20
Exelon Corp.	EXC	A2	BBB	NYSE	B+	0.70
Eversource	NU	Baa1	A-	NYSE	B	0 75
FirstEnergy Corp.	FE	Baa2	BBB-	NYSE	B+	0.70
NextEra Energy Inc.	NEE	A1	A-	NYSE	A	0.75
NiSource Inc.	NI	Baa1	BBB-	NYSE	B	NMF
NRG Energy Inc.	NRG	Ba3	BB-	NYSE	B	1.00
ONEOK, Inc.	OKE	Baa3	BB+	NYSE	A-	0.85
PG&E Corp.	PCG	A3	BBB	NYSE	B	0.65
PPL Corp.	PPL	Baa1	BBB	NYSE	B+	0.70
Pinnacle West Capital	PNW	A3	A-	NYSE	B	0.75
Public Serv. Enterprise Inc.	PEG	A2	BBB+	NYSE	B+	0.75
SCANA Corp.	SCG	Baa2	BBB+	NYSE	A-	0.75
Sempra Energy	SRE	A1	A	NYSE	B+	0.80
Southern Co.	SO	A3	A	NYSE	A-	0.60
TECO Energy	TE	A2	BBB+	NYSE	B	0.85
Wisconsin Energy Corp.	WEC	A1	A-	NYSE	A	0.70
Xcel Energy Inc	XEL	A2	A-	NYSE	B+	0.65
Average for S&P Utilities		A3	BBB+		B+	0.75

Note: [1] Ratings are those of utility subsidiaries

Source of Information: SNL Financial LLC
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Duquesne Light Company
Capitalization and Related Capital Structure Ratios
Actual at December 31, 2017 and Estimated at December 31, 2018 and December 31, 2019

	Actual at December 31, 2017			Estimated at December 31, 2018			Estimated at December 31, 2019		
	Amount	Ratios		Amount	Ratios		Amount	Ratios	
	Outstanding	Excl S-T Debt	Incl S-T Debt	Outstanding	Excl S-T Debt	Incl. S-T Debt	Outstanding	Excl. S-T Debt	Incl S-T Debt
Long-Term Debt	$ 1,096,882,297	47 41%	46 41%	$ 1,173,700,764 (2)	47 43%	46 11%	$ 1,175,738,656 (2)	45 49%	43 42%
Common Equity									
Common Stock	10			10			10		
Capital Surplus	988,426,510			986,264,247			986,264,247		
Retained earnings(1)	228,272,169			314,567,470 (3)			422,793,470 (3)		
Total Common Equity	1,216,698,689	52 59%	51 48%	1,300,831,727	52 57%	51 10%	1,409,057,727	54.51%	52 04%
Total Permanent Capital	2,313,580,986	100 00%	97 89%	2,474,532,491	100 00%	97 21%	2,584,796,383	100 00%	95 46%
Short-term Debt	50,000,000		2 12%	71,000,000		2 79%	123,000,000		4.54%
Total Capital Employed	$ 2,363,580,986		100 01%	$ 2,545,532,491		100 00%	$ 2,707,796,383		100 00%

Notes.

(1) Excluding Accumulated Other Comprehensive Income ("OCI") of

	2017	2018	2019
	$ 266,273	$ 266,273	$ 266,273

(2) Reflects changes in the principal amount of long-term debt of

	2018	2019
Beaver County 1999 Series B due 3/01/31	$ (13,700,000)	
Beaver County 1999 Series C due 8/01/33	(18,000,000)	
Beaver County 1999 Series D due 4/01/31	(44,250,000)	
Ohio Water Development Authority 1999 Series C due 3/01/31	(33,955,000)	
1st Mortgage Bond 3 89% due 2/1/48	60,000,000	
1st Mortgage Bond 4 04% due 2/1/58	125,000,000	
Net change in Loss on Reacquired Debt	1,723,467	$ 2,037,893

(3) Projection of retained earnings

Source of Information Company provided data

Duquesne Light Company
Calculation of the Embedded Cost of Long-Term Debt
Actual at December 31, 2017

Series	Principal Amount Outstanding [1]	Percent to Total	Effective Cost Rate	Weighted Cost Rate [2]
1st Mortgage Bond 4.76% due 2/3/42	$ 200,000,000	17.86%	4.81%	0.86%
1st Mortgage Bond 4.97% due 11/14/43	160,000,000	14.29%	5.01%	0.72%
1st Mortgage Bond 5.02% due 2/4/44	45,000,000	4.02%	5.06%	0.20%
1st Mortgage Bond 5.12% due 2/4/54	85,000,000	7.59%	5.16%	0.39%
1st Mortgage Bond 3.78% due 3/2/45	100,000,000	8.93%	3.81%	0.34%
1st Mortgage Bond 3.93% due 3/2/55	200,000,000	17.86%	3.95%	0.71%
1st Mortgage Bond 3.93% due 7/15/45	160,000,000	14.29%	3.96%	0.57%
1st Mortgage Bond 3.82% due 10/3/47	60,000,000	5.36%	3.87%	0.21%
Beaver County 1999 Series B due 3/01/31	13,700,000	1.22%	4.81%	0.06%
Beaver County 1999 Series C due 8/01/33	18,000,000	1.61%	4.80%	0.08%
Beaver County 1999 Series D due 4/01/31	44,250,000	3.95%	4.55%	0.18%
Ohio Water Development Authority 1999 Series C due 3/01/31	33,955,000	3.03%	4.79%	0.15%
Total Long -Term Debt	1,119,905,000	100.00%		4.45%
Unamortized Call Premium	(23,022,703)			
Long Term- Debt	$ 1,096,882,297			
Annualized Cost	$ 49,829,750			
Amortization of Loss on Reacquired Debt	2,084,666			
Total Cost	$ 51,914,416			4.73%

Notes: [1] Includes current portion of long-term debt.
[2] As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at December 31, 2018

Series	Principal Amount Outstanding [1]	Percent to Total	Effective Cost Rate	Weighted Cost Rate [2]
1st Mortgage Bond 4.76% due 2/3/42	$ 200,000,000	16.74%	4.81%	0.81%
1st Mortgage Bond 4.97% due 11/14/43	160,000,000	13.39%	5.01%	0.67%
1st Mortgage Bond 5.02% due 2/4/44	45,000,000	3.77%	5.06%	0.19%
1st Mortgage Bond 5.12% due 2/4/54	85,000,000	7.11%	5.16%	0.37%
1st Mortgage Bond 3.78% due 3/2/45	100,000,000	8.37%	3.81%	0.32%
1st Mortgage Bond 3.93% due 3/2/55	200,000,000	16.74%	3.95%	0.66%
1st Mortgage Bond 3.93% due 7/15/45	160,000,000	13.39%	3.96%	0.53%
1st Mortgage Bond 3.82% due 10/3/47	60,000,000	5.02%	3.87%	0.19%
1st Mortgage Bond 3.89% due 2/1/48	60,000,000	5.02%	3.91%	0.20%
1st Mortgage Bond 4.04% due 2/1/58	125,000,000	10.46%	4.06%	0.42%
Total Long -Term Debt	1,195,000,000	100.00%		4.36%
Unamortized Call Premium	(21,299,236)			
Long Term- Debt	$ 1,173,700,764			
Annualized Cost	$ 52,087,515			
Amortization of Loss on Reacquired Debt	2,077,706			
Total Cost	$ 54,165,221			4.61%

Notes: [1] Includes current portion of long-term debt.
[2] As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Embedded Cost of Long-Term Debt
Estimated at December 31, 2019

Series	Principal Amount Outstanding (1)	Percent to Total	Effective Cost Rate	Weighted Cost Rate (2)
1st Mortgage Bond 4.76% due 2/3/42	$ 200,000,000	16.74%	4.81%	0.81%
1st Mortgage Bond 4.97% due 11/14/43	160,000,000	13.39%	5.01%	0.67%
1st Mortgage Bond 5.02% due 2/4/44	45,000,000	3.77%	5.06%	0.19%
1st Mortgage Bond 5.12% due 2/4/54	85,000,000	7.11%	5.16%	0.37%
1st Mortgage Bond 3.78% due 3/2/45	100,000,000	8.37%	3.81%	0.32%
1st Mortgage Bond 3.93% due 3/2/55	200,000,000	16.74%	3.95%	0.66%
1st Mortgage Bond 3.93% due 7/15/45	160,000,000	13.39%	3.96%	0.53%
1st Mortgage Bond 3.82% due 10/3/47	60,000,000	5.02%	3.87%	0.19%
1st Mortgage Bond 3.89% due 2/1/48	60,000,000	5.02%	3.91%	0.20%
1st Mortgage Bond 4.04% due 2/1/58	125,000,000	10.46%	4.06%	0.42%
Total Long -Term Debt	1,195,000,000	100.00%		4.36%
Unamortized Call Premium	(19,261,344)			
Long Term- Debt	$ 1,175,738,656			
Annualized Cost	$ 52,087,515			
Amortization of Loss on Reacquired Debt	2,037,893			
Total Cost	$ 54,125,408			4.60%

Notes: (1) Includes current portion of long-term debt.
(2) As calculated on page 4 of this schedule.

Source of Information: Company provided data

Duquesne Light Company
Calculation of the Effective Cost of Long-Term Debt by Series

Series	Coupon Rate	Date of Issue	Date of Maturity	Term in Years	Principal Amount Outstanding	Premium/ Discount & Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate [1]
1st Mortgage Bond 4 76% due 2/3/42	4 76%	02/01/12	02/03/42	30 0	$ 200,000,000	$ 1,685,878	$ 198,314,122	99 16%	4 81%
1st Mortgage Bond 4 97% due 11/14/43	4 97%	11/04/13	11/14/43	30 0	160,000,000	939,240	159,060,760	99 41%	5 01%
1st Mortgage Bond 5 02% due 2/4/44	5 02%	02/01/14	02/04/44	30 0	45,000,000	272,880	44,727,120	99 39%	5 06%
1st Mortgage Bond 5 12% due 2/4/54	5 12%	02/01/14	02/04/54	40 0	85,000,000	542,400	84,457,600	99 36%	5 16%
1st Mortgage Bond 3 78% due 3/2/45	3 78%	03/01/15	03/02/45	30 0	100,000,000	446,400	99,553,600	99 55%	3 81%
1st Mortgage Bond 3 93% due 3/2/55	3 93%	03/01/15	03/02/55	40 0	200,000,000	891,840	199,108,160	99 55%	3 95%
1st Mortgage Bond 3 93% due 7/15/45	3 93%	07/15/15	07/15/45	30 0	160,000,000	781,560	159,218,440	99 51%	3 96%
1st Mortgage Bond 3 82% due 10/3/47	3 82%	10/01/17	10/03/47	30 0	60,000,000	560,640	59,439,360	99 07%	3 87%
1st Mortgage Bond 3 89% due 2/1/48	3 89%	02/01/18	02/01/48	30 0	60,000,000	240,000	59,760,000	99 60%	3 91%
1st Mortgage Bond 4 04% due 2/1/58	4 04%	02/01/18	02/01/58	40 0	125,000,000	500,000	124,500,000	99 60%	4 06%
Beaver County 1999 Series B due 3/01/31	4 75%	11/18/99	08/01/20	20 7	13,700,000	115,718	13,584,282	99 16%	4 81%
Beaver County 1999 Series C due 8/01/33	4 75%	11/18/99	08/01/33	33 7	18,000,000	150,884	17,849,116	99 16%	4 80%
Beaver County 1999 Series D due 4/01/31	4 50%	11/18/99	11/01/29	30 0	44,250,000	376,475	43,873,525	99 15%	4 55%
Ohio Water Development Authority 1999 Series C due 3/01/31	4 75%	11/18/99	03/01/31	31 3	33,955,000	205,000	33,750,000	99 40%	4 79%

Notes [1] The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio

Source of Information Company provided data

Monthly Dividend Yields for
Electric Group
for the Twelve Months Ending January 2018

Company	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	12-Month Average	6-Month Average	3-Month Average
AVANGRID, Inc (AGR)	3 99%	4 05%	4 00%	3 84%	3 92%	3 83%	3 57%	3 65%	3 36%	3 28%	3 42%	3 57%			
Consolidated Edison Inc (ED)	3 59%	3.57%	3 51%	3 34%	3.43%	3 35%	3 28%	3 44%	3 23%	3 10%	3 26%	3 59%			
Dominion Energy Inc (D)	3 93%	3 91%	3 93%	3 74%	3 95%	3 94%	3 83%	3 94%	3 82%	3 66%	3 81%	4 40%			
Duke Energy Corporation (DUK)	4 15%	4 19%	4.18%	4 00%	4 11%	4 22%	4 08%	4 26%	4 07%	4 00%	4 25%	4 58%			
Eversource Energy (ES)	3 26%	3 24%	3 22%	3 06%	3 14%	3 14%	3 04%	3.15%	3 04%	2 95%	3 01%	3 22%			
Exelon Corp (EXC)	3.57%	3 66%	3 81%	3 61%	3 65%	3.44%	3 47%	3 49%	3 28%	3 15%	3 34%	3 61%			
FirstEnergy Corp (FE)	4 45%	4 56%	4 86%	4.94%	4.98%	4 56%	4 43%	4 71%	4 42%	4 23%	4.74%	4.42%			
NextEra Energy Inc (NEE)	3 00%	3.07%	2 96%	2 78%	2.81%	2 70%	2 61%	2 69%	2 55%	2 49%	2 52%	2.82%			
PPL Corp (PPL)	4 33%	4.24%	4 17%	4 00%	4 10%	4.15%	4 06%	4.17%	4 23%	4 35%	5 12%	5 19%			
Public Service Enterprise Group Inc (PEG)	3 77%	3 89%	3 93%	3 86%	4.01%	3 85%	3 70%	3 73%	3 51%	3.27%	3.35%	3.49%			
Average	**3.80%**	**3.84%**	**3.86%**	**3.72%**	**3.81%**	**3.72%**	**3.61%**	**3.72%**	**3.55%**	**3.45%**	**3.68%**	**3.89%**	**3.72%**	**3.65%**	**3.67%**

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend

Source of Information: http //performance morningstar com/stock/performance-return
http //www snl com/interactivex/dividends

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0	
	3 65%	1.028750	3 75%	$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$
Discrete	D_0/P_0	Adj	D_1/P_0	
	3 65%	1 035686	3 78%	$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$
Quarterly	D_0/P_0	Adj	D_1/P_0	
	0 9125%	1 014075	3 75%	$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$
Average			3 76%	
Growth rate			5 75%	
K			9.51%	

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Electric Group	Earnings per Share Value Line 5 Year	Earnings per Share Value Line 10 Year	Dividends per Share Value Line 5 Year	Dividends per Share Value Line 10 Year	Book Value per Share Value Line 5 Year	Book Value per Share Value Line 10 Year	Cash Flow per Share Value Line 5 Year	Cash Flow per Share Value Line 10 Year
AVANGRID, Inc.	-	-	-	-	-	-	-	-
Consol. Edison	2.50%	3.50%	2.00%	1.50%	3.50%	4.00%	4.50%	4.50%
Dominion Energy	3.00%	5.00%	7.00%	7.00%	1.50%	2.50%	4.00%	3.50%
Duke Energy	0.50%	3.50%	2.50%	-	3.00%	-0.50%	2.50%	1.50%
Eversource Energy	6.00%	12.00%	10.50%	9.50%	8.50%	6.00%	-0.50%	0.50%
Exelon Corp.	-11.50%	-4.00%	-10.00%	-2.00%	6.00%	7.00%	-3.00%	1.00%
FirstEnergy Corp.	-10.00%	-6.00%	-8.00%	-2.50%	-3.50%	-1.00%	-5.50%	-2.50%
NextEra Energy	5.00%	8.00%	9.00%	8.50%	7.50%	8.00%	6.50%	7.50%
PPL Corp.	4.50%	2.00%	1.50%	4.50%	-	3.00%	1.50%	1.00%
Public Serv. Enterprise	-0.50%	6.00%	3.00%	3.50%	6.00%	7.50%	2.00%	5.00%
Average	-0.06%	3.33%	1.94%	3.75%	4.06%	4.06%	1.33%	2.44%

Source of Information: Value Line Investment Survey November 17, 2017

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

					Value Line				
Electric Group	I/B/E/S First Call	Zacks	Morningstar	SNL	Earnings Per Share	Dividends Per Share	Book Value Per Share	Cash Flow Per Share	Percent Retained to Common Equity
AVANGRID, Inc.	8.50%	8.30%	-	8.50%	NMF	NMF	NMF	NMF	1 50%
Consol. Edison	3.10%	2.00%	4.10%	3.49%	2.50%	3.00%	3.50%	4.00%	2 50%
Dominion Energy	6.33%	6.50%	7.00%	7.50%	6.50%	9 00%	2.50%	7.50%	2.00%
Duke Energy	2.65%	4.00%	9.00%	4.53%	4.50%	4.50%	1.50%	5.00%	2 00%
Eversource Energy	5.86%	6.00%	6.20%	5 97%	6.50%	6.00%	4.00%	7.00%	4 00%
Exelon Corp.	0.90%	4.30%	6.30%	3.00%	8 50%	5 50%	4 00%	5.50%	4.50%
FirstEnergy Corp.		1 00%	1.90%	2.00%	12.00%	2.00%	Nil	3.00%	7 00%
NextEra Energy	8.85%	7.90%	9.90%	8.00%	7.00%	9 50%	5.00%	5 50%	5.00%
PPL Corp.		7 00%		4.50%	NMF	3.00%	NMF	NMF	4 50%
Public Serv. Enterprise	2.41%	3.40%	4.50%	3.77%	1.00%	5.00%	3.00%	3.50%	3.50%
Average	4.83%	5.04%	6 11%	5.13%	6.06%	5.28%	3.36%	5.13%	3.65%

Note: Negative growth rates removed for FirstEnergy of -4 74% by I/B/E/S First Call and for PPL Corp of -1.00% by I/B/E/S First Call and -0.10% by Morningstar.

Source of Information : Yahoo Finance, February 7, 2018
Zacks, February 7, 2018
Morningstar, February 7, 2018
SNL, February 7, 2018
Value Line Investment Survey November 17, 2017

Electric Group[1]
Financial Risk Adjustment

	AVANGRID Inc (AGR)	Consolidated Edison Inc (ED)	Dominion Resources Inc (D)	Duke Energy Corporation (DUK)	Eversource Energy (ES)	Exelon Corp(EXC)	FirstEnergy Corp (FE)	NextEra Energy Inc (NEE)	PPL Corp (PPL)	Public Service Enterprise Group Inc (PEG)	Average
Fiscal Year	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	12/31/16	
Capitalization at Fair Values											
Debt(D)	5,204,000	16,093,000	33,584,000	49,161,000	9,980,500	35,480,000	19,829,000	31,623,000	21,355,000	12,003,000	23,431,250
Preferred(P)	0	0	0	0	158,300	0	0	0	0	0	15,830
Equity(E)	11,704,660	20,777,760	48,098,520	54,334,000	17,501,603	32,794,004	13,699,400	55,907,280	23,144,841	22,153,529	30,011,560
Total	16,908,660	36,870,760	81,682,520	103,495,000	27,640,403	68,274,004	33,528,400	87,530,280	44,499,841	34,156,529	53,458,640
Capital Structure Ratios											
Debt(D)	30 78%	43 65%	41 12%	47 50%	36 11%	51 97%	59 14%	36 13%	47 99%	35 14%	42 95%
Preferred(P)	0 00%	0 00%	0 00%	0 00%	0 57%	0 00%	0 00%	0 00%	0 00%	0 00%	0 06%
Equity(E)	69 22%	56 35%	58 88%	52 50%	63 32%	48 03%	40 86%	63 87%	52 01%	64 86%	56 99%
Total	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%
Common Stock											
Issued		305,000 000		700,000 000			442,344 218	468,000 000	679,731 000		
Treasury		23,000 000		0 000			0 000	0 000	0 000		
Outstanding	308,993 149	282,000 000	628,000 000	700,000 000	316,885 808	924,035 059	442,344 218	468,000 000	679,731 000	504,866 212	
Market Price	$37 88	$73 68	$76 59	$77 62	$55 23	$35 49	$30 97	$119 46	$34 05	$43 88	
Capitalization at Carrying Amounts											
Debt(D)	4,859,000	14,774,000	31,940,000	47,895,000	9,603,200	34,646,000	19,885,000	30,418,000	18,326,000	11,395,000	22,374,120
Preferred(P)	0	0	0	0	155,600	0	0	0	0	0	15,560
Equity(E)	15,109,000	14,298,000	14,605,000	41,033,000	10,711,734	25,837,000	6,241,000	24,341,000	9,899,000	13,130,473	17,520,473
Total	19,968,000	29,072,000	46,545,000	88,928,000	20,470,534	60,483,000	26,126,000	54,759,000	28,225,000	24,525,000	39,910,153
Capital Structure Ratios											
Debt(D)	24 33%	50 82%	68 62%	53 86%	46 91%	57 28%	76 11%	55 55%	64 93%	46 46%	54 49%
Preferred(P)	0 00%	0 00%	0 00%	0 00%	0 76%	0 00%	0 00%	0 00%	0 00%	0 00%	0 08%
Equity(E)	75 67%	49 18%	31 38%	46 14%	52 33%	42 72%	23 89%	44 45%	35 07%	53 54%	45 44%
Total	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 00%	100 01%
Betas Value Line	NMF	0 50	0 65	0 60	0 65	0 70	0 70	0 65	0 75	0 70	0 66

Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0 66	=	Bu	[1+	(1-0 21)	0 7536	+	0 0011	]
	0 66	=	Bu	[1+	0 79	0 7536	+	0 0011	]
	0 66	=	Bu	1 5964					
	0 41	=	Bu						

Hamada	Bl	=	0 41	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0 41	[1+	0 79	1 1992	+	0 0018	]
	Bl	=	0 41	1 9492					
	Bl	=	0 80						

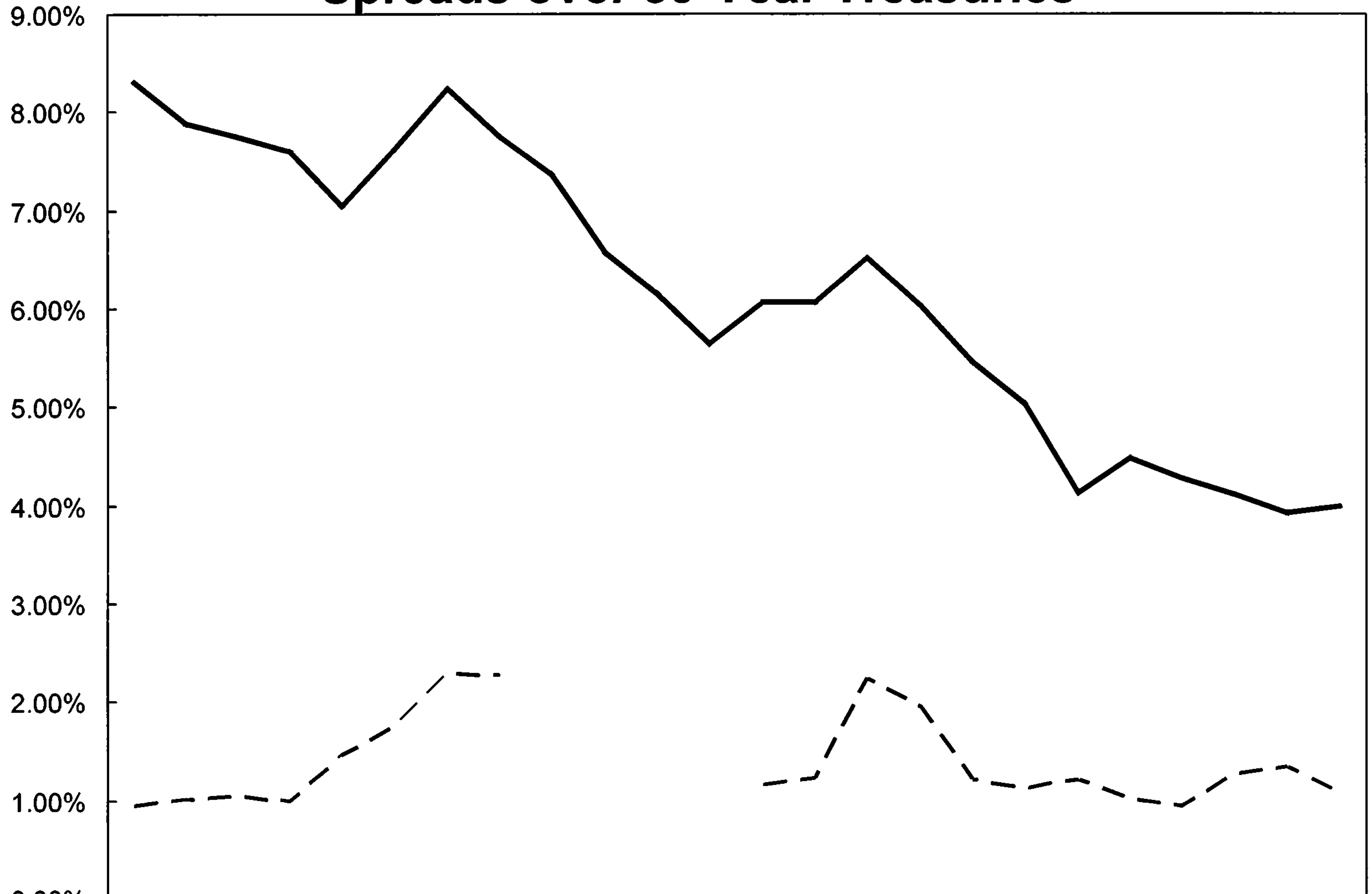
M&M	ku	=	ke	-	(((	ku	-	t	)	1-t	)	D	/	E	) - (	ku	-	d	)	P	/	E
	7 40%	=	9 51%	-	(((	7 40%	-	3 85%	)	0 79	)	42 95%	/	56 99%	) - (	7 40%	-	5 68%	)	0 06%	/	56 99%
	7 40%	=	9 51%	-	(((	3 55%			)	0 79	)	0 7536			) - (	1 72%			)	0 0011		
	7 40%	=	9 51%	-	((	2 80%					)	0 7536			) - (	1 72%			)	0 0011		
	7 40%	=	9 51%	-		2 11%									-	0 00%						

M&M	ke	=	ku	+	(((	ku	-	t	)	1-t	)	D	/	E	) + (	ku	-	d	)	P	/	E
	10 76%	=	7 40%	+	(((	7 40%	-	3 85%	)	0 79	)	54 49%	/	45 44%	) + (	7 40%	-	5 68%	)	0 08%	/	45 44%
	10 76%	=	7 40%	+	(((	3 55%			)	0 79	)	1 1992			) + (	1 72%			)	0 0018		
	10 76%	=	7 40%	+	((	2 80%					)	1 1992			) + (	1 72%			)	0 0018		
	10 76%	=	7 40%	+		3 36%									+	0 00%						

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2012-2016 and 2017
and the Twelve Months Ended January 2018

Years	Aa Rated	A Rated	Baa Rated	Average
2012	3.83%	4.13%	4.86%	4.27%
2013	4.24%	4.48%	4.98%	4.57%
2014	4.19%	4.28%	4.80%	4.42%
2015	4.00%	4.12%	5.03%	4.38%
2016	3.73%	3.93%	4.68%	4.11%
Five-Year Average	4.00%	4.19%	4.87%	4.35%
2017	3.82%	4.00%	4.38%	4.07%
Months				
Feb-17	3.99%	4.18%	4.58%	4.25%
Mar-17	4.04%	4.23%	4.62%	4.30%
Apr-17	3.93%	4.12%	4.51%	4.19%
May-17	3.94%	4.12%	4.50%	4.19%
Jun-17	3.77%	3.94%	4.32%	4.01%
Jul-17	3.82%	3.99%	4.36%	4.06%
Aug-17	3.67%	3.86%	4.23%	3.92%
Sep-17	3.70%	3.87%	4.24%	3.93%
Oct-17	3.74%	3.91%	4.26%	3.97%
Nov-17	3.65%	3.83%	4.16%	3.88%
Dec-17	3.62%	3.79%	4.14%	3.85%
Jan-18	3.69%	3.86%	4.18%	3.91%
Twelve-Month Average	3.80%	3.98%	4.34%	4.04%
Six-Month Average	3.68%	3.85%	4.20%	3.91%
Three-Month Average	3.65%	3.83%	4.16%	3.88%

Yields on A-rated Public Utility Bonds and Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
A-rated Public Utility	8.31%	7 89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6 07%	6.07%	6.53%	6.04%	5.46%	5.04%	4.13%	4.48%	4.28%	4 12%	3.93%	4 00%
Spread vs. 30-year	0.94%	1 01%	1 04%	0.99%	1.46%	1.75%	2.30%	2.27%					1 16%	1.23%	2.25%	1.96%	1.21%	1.13%	1.21%	1.03%	0.94%	1 28%	1.34%	1 10%

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasunes Yield	30-Year Treasunes Spread
Jan-99	6 97%	5 16%	1 81%
Feb-99	7 09%	5 37%	1 72%
Mar-99	7 26%	5 58%	1 68%
Apr-99	7 22%	5 55%	1 67%
May-99	7 47%	5 81%	1 66%
Jun-99	7 74%	6 04%	1 70%
Jul-99	7 71%	5 98%	1 73%
Aug-99	7 91%	6 07%	1 84%
Sep-99	7 93%	6 07%	1 86%
Oct-99	8 06%	6 26%	1 80%
Nov-99	7 94%	6 15%	1 79%
Dec-99	8 14%	6 35%	1 79%
Jan-00	8 35%	6 63%	1 72%
Feb-00	8 25%	6 23%	2 02%
Mar-00	8 28%	6 05%	2 23%
Apr-00	8 29%	5 85%	2 44%
May-00	8 70%	6 15%	2 55%
Jun-00	8 36%	5 93%	2 43%
Jul-00	8 25%	5 85%	2 40%
Aug-00	8 13%	5 72%	2 41%
Sep-00	8 23%	5 83%	2 40%
Oct-00	8 14%	5 80%	2 34%
Nov-00	8 11%	5 78%	2 33%
Dec-00	7 84%	5 49%	2 35%
Jan-01	7 80%	5 54%	2 26%
Feb-01	7 74%	5 45%	2 29%
Mar-01	7 68%	5 34%	2 34%
Apr-01	7 94%	5 65%	2 29%
May-01	7 99%	5 78%	2 21%
Jun-01	7 85%	5 67%	2 18%
Jul-01	7 78%	5 61%	2 17%
Aug-01	7 59%	5 48%	2 11%
Sep-01	7 75%	5 48%	2 27%
Oct-01	7 63%	5 32%	2 31%
Nov-01	7 57%	5 12%	2 45%
Dec-01	7 83%	5 48%	2 35%
Jan-02	7 66%	5 45%	2 21%
Feb-02	7 54%	5 40%	2 14%
Mar-02	7 76%		
Apr-02	7 57%		
May-02	7 52%		
Jun-02	7 42%		
Jul-02	7 31%		
Aug-02	7 17%		
Sep-02	7 08%		
Oct-02	7 23%		
Nov-02	7 14%		
Dec-02	7 07%		

Year	A-rated Public Utility	30-Year Treasunes Yield	30-Year Treasunes Spread
Jan-03	7 07%		
Feb-03	6 93%		
Mar-03	6 79%		
Apr-03	6 64%		
May-03	6 36%		
Jun-03	6 21%		
Jul-03	6 57%		
Aug-03	6 78%		
Sep-03	6 56%		
Oct-03	6 43%		
Nov-03	6 37%		
Dec-03	6 27%		
Jan-04	6 15%		
Feb-04	6 15%		
Mar-04	5 97%		
Apr-04	6 35%		
May-04	6 62%		
Jun-04	6 46%		
Jul-04	6 27%		
Aug-04	6 14%		
Sep-04	5 98%		
Oct-04	5 94%		
Nov-04	5 97%		
Dec-04	5 92%		
Jan-05	5 78%		
Feb-05	5 61%		
Mar-05	5 83%		
Apr-05	5 64%		
May-05	5 53%		
Jun-05	5 40%		
Jul-05	5 51%		
Aug-05	5 50%		
Sep-05	5 52%		
Oct-05	5 79%		
Nov-05	5 88%		
Dec-05	5 80%		
Jan-06	5 75%		
Feb-06	5 82%	4 54%	1 28%
Mar-06	5 98%	4 73%	1 25%
Apr-06	6 29%	5 06%	1 23%
May-06	6 42%	5 20%	1 22%
Jun-06	6 40%	5 15%	1 25%
Jul-06	6 37%	5 13%	1 24%
Aug-06	6 20%	5 00%	1 20%
Sep-06	6 00%	4 85%	1 15%
Oct-06	5 98%	4 85%	1 13%
Nov-06	5 80%	4 69%	1 11%
Dec-06	5 81%	4 68%	1 13%

Year	A-rated Public Utility	30-Year Treasunes Yield	30-Year Treasunes Spread
Jan-07	5 96%	4 85%	1 11%
Feb-07	5 90%	4 82%	1 08%
Mar-07	5 85%	4 72%	1 13%
Apr-07	5 97%	4 87%	1 10%
May-07	5 99%	4 90%	1 09%
Jun-07	6 30%	5 20%	1 10%
Jul-07	6 25%	5 11%	1 14%
Aug-07	6 24%	4 93%	1 31%
Sep-07	6 18%	4 79%	1 39%
Oct-07	6 11%	4 77%	1 34%
Nov-07	5 97%	4 52%	1 45%
Dec-07	6 16%	4 53%	1 63%
Jan-08	6 02%	4 33%	1 69%
Feb-08	6 21%	4 52%	1 69%
Mar-08	6 21%	4 39%	1 82%
Apr-08	6 29%	4 44%	1 85%
May-08	6 28%	4 60%	1 68%
Jun-08	6 38%	4 69%	1 69%
Jul-08	6 40%	4 57%	1 83%
Aug-08	6 37%	4 50%	1 87%
Sep-08	6 49%	4 27%	2 22%
Oct-08	7 56%	4 17%	3 39%
Nov-08	7 60%	4 00%	3 60%
Dec-08	6 52%	2 87%	3 65%
Jan-09	6 39%	3 13%	3 26%
Feb-09	6 30%	3 59%	2 71%
Mar-09	6 42%	3 64%	2 78%
Apr-09	6 48%	3 76%	2 72%
May-09	6 49%	4 23%	2 26%
Jun-09	6 20%	4 52%	1 68%
Jul-09	5 97%	4 41%	1 56%
Aug-09	5 71%	4 37%	1 34%
Sep-09	5 53%	4 19%	1 34%
Oct-09	5 55%	4 19%	1 36%
Nov-09	5 64%	4 31%	1 33%
Dec-09	5 79%	4 49%	1 30%
Jan-10	5 77%	4 60%	1 17%
Feb-10	5 87%	4 62%	1 25%
Mar-10	5 84%	4 64%	1 20%
Apr-10	5 81%	4 69%	1 12%
May-10	5 50%	4 29%	1 21%
Jun-10	5 46%	4 13%	1 33%
Jul-10	5 26%	3 99%	1 27%
Aug-10	5 01%	3 80%	1 21%
Sep-10	5 01%	3 77%	1 24%
Oct-10	5 10%	3 87%	1 23%
Nov-10	5 37%	4 19%	1 18%
Dec-10	5 56%	4 42%	1 14%

Year	A-rated Public Utility	30-Year Treasunes Yield	30-Year Treasunes Spread
Jan-11	5 57%	4 52%	1 05%
Feb-11	5 68%	4 65%	1 03%
Mar-11	5 56%	4 51%	1 05%
Apr-11	5 55%	4 50%	1 05%
May-11	5 32%	4 29%	1 03%
Jun-11	5 26%	4 23%	1 03%
Jul-11	5 27%	4 27%	1 00%
Aug-11	4 69%	3 65%	1 04%
Sep-11	4 48%	3 18%	1 30%
Oct-11	4 52%	3 13%	1 39%
Nov-11	4 25%	3 02%	1 23%
Dec-11	4 33%	2 98%	1 35%
Jan-12	4 34%	3 03%	1 31%
Feb-12	4 36%	3 11%	1 25%
Mar-12	4 48%	3 28%	1 20%
Apr-12	4 40%	3 18%	1 22%
May-12	4 20%	2 93%	1 27%
Jun-12	4 08%	2 70%	1 38%
Jul-12	3 93%	2 59%	1 34%
Aug-12	4 00%	2 77%	1 23%
Sep-12	4 02%	2 88%	1 14%
Oct-12	3 91%	2 90%	1 01%
Nov-12	3 84%	2 80%	1 04%
Dec-12	4 00%	2 88%	1 12%
Jan-13	4 15%	3 08%	1 07%
Feb-13	4 18%	3 17%	1 01%
Mar-13	4 20%	3 16%	1 04%
Apr-13	4 00%	2 93%	1 07%
May-13	4 17%	3 11%	1 06%
Jun-13	4 53%	3 40%	1 13%
Jul-13	4 68%	3 61%	1 07%
Aug-13	4 73%	3 76%	0 97%
Sep-13	4 80%	3 79%	1 01%
Oct-13	4 70%	3 68%	1 02%
Nov-13	4 77%	3 80%	0 97%
Dec-13	4 81%	3 89%	0 92%
Jan-14	4 63%	3 77%	0 86%
Feb-14	4 53%	3 66%	0 87%
Mar-14	4 51%	3 62%	0 89%
Apr-14	4 41%	3 52%	0 89%
May-14	4 26%	3 39%	0 87%
Jun-14	4 29%	3 42%	0 87%
Jul-14	4 23%	3 33%	0 90%
Aug-14	4 13%	3 20%	0 93%
Sep-14	4 24%	3 26%	0 98%
Oct-14	4 06%	3 04%	1 02%
Nov-14	4 09%	3 04%	1 05%
Dec-14	3 95%	2 83%	1 12%

Year	A-rated Public Utility	30-Year Treasuries Yield	30-Year Treasuries Spread
Jan-15	3 58%	2 46%	1 12%
Feb-15	3 67%	2 57%	1 10%
Mar-15	3 74%	2 63%	1 11%
Apr-15	3 75%	2 59%	1 16%
May-15	4 17%	2 96%	1 21%
Jun-15	4 39%	3 11%	1 28%
Jul-15	4 40%	3 07%	1 33%
Aug-15	4 25%	2 86%	1 39%
Sep-15	4 39%	2 95%	1 44%
Oct-15	4 29%	2 89%	1 40%
Nov-15	4 40%	3 03%	1 37%
Dec-15	4 35%	2 97%	1 38%
Jan-16	4 27%	2 86%	1 41%
Feb-16	4 11%	2 62%	1 49%
Mar-16	4 16%	2 68%	1 48%
Apr-16	4 00%	2 62%	1 38%
May-16	3 93%	2 63%	1 30%
Jun-16	3 78%	2 45%	1 33%
Jul-16	3 57%	2 23%	1 34%
Aug-16	3 59%	2 26%	1 33%
Sep-16	3 66%	2 35%	1 31%
Oct-16	3 77%	2 50%	1 27%
Nov-16	4 08%	2 86%	1 22%
Dec-16	4 27%	3 11%	1 16%
Jan-17	4 14%	3 02%	1 12%
Feb-17	4 18%	3 03%	1 15%
Mar-17	4 23%	3 08%	1 15%
Apr-17	4 12%	2 94%	1 18%
May-17	4 12%	2 96%	1 16%
Jun-17	3 94%	2 80%	1 14%
Jul-17	3 99%	2 88%	1 11%
Aug-17	3 86%	2 80%	1 06%
Sep-17	3 87%	2 78%	1 09%
Oct-17	3 91%	2 88%	1 03%
Nov-17	3 83%	2 80%	1 03%
Dec-17	3 79%	2 77%	1 02%
Jan-18	3 86%	2 88%	0 98%
Average			
12-months			1 09%
6-months			1 04%
3-months			1 01%

Common Equity Risk Premiums
Years 1926-2016

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	11.97%	4.89%	7.08%	2.96%
Average Across All Interest Rates	11.95%	6.31%	5.64%	5.07%
High Interest Rates	11.93%	7.75%	4.18%	7.22%

Source of Information: 2017 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
1940	-9 78%	3 39%	1 94%
1945	36 44%	4 08%	1 99%
1941	-11 59%	2 73%	2 04%
1949	18 79%	3 31%	2 09%
1946	-8 07%	1 72%	2 12%
1950	31 71%	2 12%	2 24%
1939	-0 41%	3 97%	2 26%
1948	5 50%	4 14%	2 37%
1947	5 71%	-2 34%	2 43%
1942	20 34%	2 60%	2 46%
1944	19 75%	4 73%	2 46%
2012	16 00%	10 68%	2 46%
2014	13 69%	17 28%	2 46%
1943	25 90%	2 83%	2 48%
1938	31 12%	6 13%	2 52%
1936	33 92%	6 74%	2 55%
2011	2 11%	17 95%	2 55%
2015	1 38%	-1 02%	2 68%
1951	24 02%	-2 69%	2 69%
1954	52 62%	5 39%	2 72%
2016	11 96%	6 70%	2 72%
1937	-35 03%	2 75%	2 73%
1953	-0 99%	3 41%	2 74%
1935	47 67%	9 61%	2 76%
1952	18 37%	3 52%	2 79%
1934	-1 44%	13 84%	2 93%
1955	31 56%	0 48%	2 95%
2008	-37 00%	8 78%	3 03%
1932	-8 19%	10 82%	3 15%
1927	37 49%	7 44%	3 17%
1957	-10 78%	8 71%	3 23%
1930	-24 90%	7 98%	3 30%
1933	53 99%	10 38%	3 36%
1928	43 61%	2 84%	3 40%
1929	-8 42%	3 27%	3 40%
1956	6 56%	-6 81%	3 45%
1926	11 62%	7 37%	3 54%
2013	32 39%	-7 07%	3 78%
1960	0 47%	9 07%	3 80%
1958	43 36%	-2 22%	3 82%
1962	-8 73%	7 95%	3 95%
1931	-43 34%	-1 85%	4 07%
2010	15 06%	12 44%	4 14%
1961	26 89%	4 82%	4 15%
1963	22 80%	2 19%	4 17%
1964	16 48%	4 77%	4 23%
1959	11 96%	-0 97%	4 47%
1965	12 45%	-0 46%	4 50%
2007	5 49%	2 60%	4 50%
1966	-10 06%	0 20%	4 55%
2009	26 46%	3 02%	4 58%
2005	4 91%	5 87%	4 61%
2002	-22 10%	16 33%	4 84%
2004	10 88%	8 72%	4 84%
2006	15 79%	3 24%	4 91%
2003	28 68%	5 27%	5 11%
1998	28 58%	10 76%	5 42%
1967	23 98%	-4 95%	5 56%
2000	-9 10%	12 87%	5 58%
2001	-11 89%	10 65%	5 75%
1971	14 30%	11 01%	5 97%
1968	11 06%	2 57%	5 98%
1972	18 99%	7 26%	5 99%
1997	33 36%	12 95%	6 02%
1995	37 58%	27 20%	6 03%
1970	3 86%	18 37%	6 48%
1993	10 08%	13 19%	6 54%
1996	22 96%	1 40%	6 73%
1999	21 04%	-7 45%	6 82%
1969	-8 50%	-8 09%	6 87%
1976	23 93%	18 65%	7 21%
1973	-14 69%	1 14%	7 26%
1992	7 62%	9 39%	7 26%
1991	30 47%	19 89%	7 30%
1974	-26 47%	-3 06%	7 60%
1986	18 67%	19 85%	7 89%
1994	1 32%	-5 76%	7 99%
1977	-7 16%	1 71%	8 03%
1975	37 23%	14 64%	8 05%
1989	31 69%	16 23%	8 16%
1990	-3 10%	6 78%	8 44%
1978	6 57%	-0 07%	8 98%
1988	16 61%	10 70%	9 19%
1987	5 25%	-0 27%	9 20%
1985	31 73%	30 09%	9 56%
1979	18 61%	-4 18%	10 12%
1982	21 55%	42 56%	10 95%
1984	6 27%	16 86%	11 70%
1983	22 56%	6 26%	11 97%
1980	32 50%	-2 76%	11 99%
1981	-4 92%	-1 24%	13 34%

Yields for Treasury Constant Maturities
Yearly for 2012-2016 and 2017
and the Twelve Months Ended January 2018

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2012	0.17%	0.28%	0.38%	0.76%	1.22%	1.80%	2.54%	2.92%
2013	0.13%	0.31%	0.54%	1.17%	1.74%	2.35%	3.12%	3.45%
2014	0.12%	0.46%	0.90%	1.64%	2.14%	2.54%	3.07%	3.34%
2015	0.32%	0.69%	1.03%	1.53%	1.89%	2.14%	2.55%	2.84%
2016	0.61%	0.84%	1.01%	1.34%	1.64%	1.84%	2.23%	2.60%
Five-Year Average	0.27%	0.52%	0.77%	1.29%	1.73%	2.13%	2.70%	3.03%
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
Months								
Feb-17	0.82%	1.20%	1.47%	1.90%	2.22%	2.42%	2.76%	3.03%
Mar-17	1.01%	1.31%	1.59%	2.01%	2.30%	2.48%	2.83%	3.08%
Apr-17	1.04%	1.24%	1.44%	1.82%	2.10%	2.30%	2.67%	2.94%
May-17	1.12%	1.30%	1.48%	1.84%	2.11%	2.30%	2.70%	2.96%
Jun-17	1.20%	1.34%	1.49%	1.77%	2.01%	2.19%	2.54%	2.80%
Jul-17	1.22%	1.37%	1.54%	1.87%	2.13%	2.32%	2.65%	2.88%
Aug-17	1.23%	1.34%	1.48%	1.78%	2.03%	2.21%	2.55%	2.80%
Sep-17	1.28%	1.38%	1.51%	1.80%	2.03%	2.20%	2.53%	2.78%
Oct-17	1.40%	1.55%	1.68%	1.98%	2.20%	2.36%	2.65%	2.88%
Nov-17	1.56%	1.70%	1.81%	2.05%	2.23%	2.35%	2.60%	2.80%
Dec-17	1.70%	1.84%	1.96%	2.18%	2.32%	2.40%	2.60%	2.77%
Jan-18	1.80%	2.03%	2.15%	2.38%	2.51%	2.58%	2.73%	2.88%
Twelve-Month Average	1.28%	1.47%	1.63%	1.95%	2.18%	2.34%	2.65%	2.88%
Six-Month Average	1.50%	1.64%	1.77%	2.03%	2.22%	2.35%	2.61%	2.82%
Three-Month Average	1.69%	1.86%	1.97%	2.20%	2.35%	2.44%	2.64%	2.82%

Measures of the Risk-Free Rate & Corporate Bond Yields
The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated February 1, 2018

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2018	First	1.8%	2.0%	2.3%	2.6%	3.0%	3.8%	4.5%
2018	Second	2.0%	2.2%	2.5%	2.8%	3.1%	4.0%	4.7%
2018	Third	2.2%	2.3%	2.6%	2.9%	3.3%	4.2%	4.9%
2018	Fourth	2.4%	2.5%	2.8%	3.0%	3.4%	4.3%	5.0%
2019	First	2.5%	2.7%	2.9%	3.1%	3.5%	4.5%	5.2%
2019	Second	2.7%	2.8%	3.0%	3.2%	3.6%	4.6%	5.4%

Measures of the Market Premium

Value Line Return					
As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
26-Jan-18	1.9%	+	5.74%	=	7.64%

DCF Result for the S&P 500 Composite					
D/P	(1+.5g)	+	g	=	k
1.74%	(1.0515)	+	10.30%	=	12.13%
where:	Price (P)	at	31-Jan-18	=	2823.81
	Dividend (D)	for	3rd Qtr. '17	=	12.31
	Dividend (D)		annualized	=	49.24
	Growth (g)	by	Morningstar	=	10.30%

Summary			
Value Line			
S&P 500			12.13%
Average			12.13%
Risk-free Rate of Return (Rf)			3.75%
Forecast Market Premium			8.38%
Historical Market Premium	(Rm)	(Rf)	
1926-2016 Arith. mean	11.96%	4.02%	7.94%
Average - Forecast/Historical			8.16%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach

Using Non-Utility Companies with
Timeliness of 1, 2, 3, 4 & 5; Safety Rank of 1, 2 & 3, Financial Strength of B+, B++, A, A+ & A++;
Price Stability of 85 to 100; Betas of .50 to 75; and Technical Rank of 2, 3, 4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Campbell Soup Co	Food Processing	4	2	B++	90	0.75	4
Capitol Federal Financial Inc	Thrift	4	2	B+	100	0.75	3
CBOE Holdings Inc	Brokers & Exchanges	2	2	B++	85	0.70	3
Church and Dwight Co Inc	Household Products	2	1	A+	100	0.70	3
Clorox Co	Household Products	3	2	B++	100	0 65	2
CME Group Inc	Brokers & Exchanges	2	2	A	90	0.75	4
Coca Cola Company	Beverage	4	1	A++	100	0.70	3
Eli Lilly and Co	Drug	2	1	A++	90	0.75	2
Forrester Research Inc	Information Services	5	3	B+	85	0 70	2
General Mills Inc	Food Processing	4	1	A+	100	0.75	4
Hershey Company	Food Processing	4	2	B++	95	0.75	2
Hormel Foods Corporation	Food Processing	4	2	A	85	0 75	3
JM Smucker Company	Food Processing	4	1	A++	90	0.75	4
Kellogg Company	Food Processing	3	1	A	100	0 70	5
Kimberly Clark Corp	Household Products	3	1	A++	95	0.75	4
Philip Morris International In	Tobacco	3	2	B++	95	0.75	3
Republic Services Inc	Environmental	2	2	B++	100	0 75	3
Sysco Corp	Retail/Wholesale Food	3	1	A+	95	0.75	4
Walmart Inc.	Retail Store	4	1	A++	95	0 70	3
Waste Management	Environmental	2	1	A	100	0.75	3
Average		3	2	A	95	0.73	3
Electric Group	Average	3	2	A	95	0.66	4

Source of Information: Value Line Investment Survey for Windows, February 2018

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2012-2016 and
Projected 3-5 Year Returns

Company	2012	2013	2014	2015	2016	Average	Projected 2020-22
Campbell Soup Co	87.2%	64.6%	49 5%	60.2%	59.9%	64.3%	29.5%
Capitol Federal Financial Inc	4.1%	4.2%	5 2%	5.5%	6.0%	5.0%	7 5%
CBOE Holdings Inc	65.8%	61.9%	75.9%	79.0%	58.4%	68.2%	12.5%
Church and Dwight Co Inc	17.0%	17.1%	19 7%	21.4%	23.5%	19.7%	19.0%
Clorox Co	-	NMF	NMF	NMF	NMF	-	69 0%
CME Group Inc	4 7%	4 6%	5 4%	6.1%	7.5%	5.7%	8.5%
Coca Cola Company	27.5%	28.3%	30.0%	34.4%	36.2%	31.3%	47.0%
Eli Lilly and Co	25 6%	25 5%	19 4%	25.1%	26.7%	24.5%	27.0%
Forrester Research Inc	8.6%	9.7%	13.2%	16.1%	16.5%	12.8%	17.0%
General Mills Inc	26.6%	26 8%	27 9%	35.3%	36.3%	30.6%	35.0%
Hershey Company	71.4%	52.6%	61.6%	91.2%	120.7%	79.5%	48.5%
Hormel Foods Corporation	17.7%	15 9%	16 7%	17.9%	20.0%	17.6%	18.5%
JM Smucker Company	11 4%	11 7%	7 8%	10.0%	11.0%	10.4%	11.5%
Kellogg Company	53 6%	38 9%	50 1%	59.1%	69.0%	54.1%	43.0%
Kimberly Clark Corp	35 1%	44 1%	202 5%	NMF	NMF	93.9%	NMF
Philip Morris International Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Republic Services Inc	8 6%	9 0%	9 0%	9.3%	9.9%	9 2%	10 5%
Sysco Corp	23 9%	19 1%	17 7%	20 9%	34.9%	23 3%	83 0%
Walmart Inc.	22.3%	21.9%	20.2%	18 2%	17 3%	20 0%	20.5%
Waste Management	15.2%	17.7%	19.7%	21 6%	24 5%	19 7%	28.0%
Average						32.8%	29.8%
Average (excluding companies with values >20%)						11.5%	13.2%

Comparable Earnings Approach
Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure) Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet Safety Ranks range from 1 (Highest) to 5 (Lowest) Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others The ratings range from A++ to C in nine steps (For screening purposes, think of an A rating as "greater than" a B) Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies Those who don't quite merit the top rating are given an A+ grade, and so on A rating as low as C++ is considered satisfactory A rating of C+ is well below average, and C is reserved for companies with very serious financial problems The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years The lower the standard deviation of the changes, the more stable the stock Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100, the next 5%, 95, and so on down to 5 One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years When the range is wide, the standard deviation is high and the stock's Price Stability Index is low

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average A Beta of 1 50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years In the case of shorter price histories, a smaller time period is used, but two years is the minimum The Betas are periodically adjusted for their long-term tendency to regress toward 1 00

Technical Rank

A prediction of relative price movement, primarily over the next three to six months It is a function of price action relative to all stocks followed by Value Line Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months Stocks ranked 3 (Average) will probably advance or decline with the market Investors should use the Technical and Timeliness Ranks as complements to one another

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3000124

Duquesne Light Company

Statement No. 13

Direct Testimony of James Milligan

Dated: March 28, 2018

Q. Please state your full name and business address.

A. James H. Milligan, 411 Seventh Avenue MD 7-3, Pittsburgh PA 15219.

Q. On whose behalf are you testifying?

A. Duquesne Light Company ("Duquesne Light" or "Company").

Q. What is your position at Duquesne Light?

A. I am the Assistant Treasurer.

Q. What are your current responsibilities?

A. I am responsible for cash management, corporate insurance, capital markets transactions, pension administration, bank and rating agency relationship management, accounts payable, timekeeping and payroll.

Q. Please describe your professional experience and educational background.

A. I received a Bachelor of Science in Marketing and Economics from Indiana University of Pennsylvania and a Master of Business Administration from the University of Pittsburgh. I am also a Certified Treasury Professional. I have been employed at Duquesne Light since February 2008 and in my current role since 2014. Prior to joining Duquesne Light, I served in various finance positions at Strategic Energy LLC and FirstEnergy Corp.

Q. Have you previously testified before the Commission or other regulatory agencies?

A. Yes, I testified in Duquesne Light's 2013 distribution rate case Docket No. R-2013-2372129.

Q. What is the purpose of your testimony?

A. I will explain the Company's current and future capital structure, cost of long-term debt, current credit ratings and the importance of maintaining Duquesne Light's credit ratings, which have been challenged by the recently enacted federal corporate income tax reform, known as the Tax Cuts and Jobs Act. I will also explain the Company's request for a revision to the current dividend reporting requirement included in the Duquesne Light Company Focused Management and Operations Audit Recommendation on Dividend Payouts (D-2011-2269361). Finally, I will discuss the Company's Liability Driven Investment ("LDI") strategy for the Company's pension assets.

Q. Are you sponsoring any data filing requirements as part of your testimony?

A. Yes, I am sponsoring Duquesne Light's capitalization and cost of capital schedules. Please see Exhibit JHM-1 to see a list of data filing requirements that I am sponsoring.

Q. Please review Duquesne Light's current and future capital structure.

A. The capital structure as of December 31, 2017 was approximately 47.5% debt and 52.5% equity. In October 2017, Duquesne Light issued $60.0 million of 3.82% first mortgage bonds ("FMB") to fund capital expenditures, redeem $33 million of preferred stock and other general corporate purposes. In February 2018 (the FTY), Duquesne Light issued $60.0 million of 3.89% and $125.0 million of 4.04% FMB through a deferred draw private placement. Proceeds of the February issuance will be used to fund capital expenditures, refinance $65.7 million of pollution control revenue refunding bonds with a mandatory put date of May 15, 2018, refinance $44.25 million of pollution control revenue refunding bonds that are optionally redeemable at any time, and other general corporate purposes. During 2018 and 2019, the Company anticipates paying lower dividends compared to the last several years in order to support the Company's capital program, some of which is directly related to the Company's long-term infrastructure improvement plan (LTIP), and to provide further credit support to the Company following Tax Reform which I will explain later in my testimony. As a result of the incremental debt issued during the FTY, as well as other anticipated changes to the capital structure such as earnings and dividends, the Company's equity as a percentage of total capitalization is projected to increase to between 53.0% and 54.5% by the end of the FPFTY.

Q. **What capital structure ratios did the Company use to calculate the revenue requirement in this proceeding?**

A. For calculating the revenue requirement, the Company used a capital structure ratio of 45.5% debt and 54.5% equity, which represents the upper end of the range for equity capitalization. The equity capitalization is slightly higher than the actual equity capitalization of 52.5% as of December 31, 2017. The capital structure is consistent with Duquesne Light's capital structure in the FPFTY and, as described by Mr. Paul Moul, is within a reasonable range compared to Duquesne Light's peers. This capital structure is also supportive of the increased equity required to be retained for the Company's capital program and for maintaining the Company's investment grade credit ratings in the wake of recent federal income tax reform.

Q. **What is the cost of long-term debt for Duquesne Light?**

A. The total adjusted long-term cost of debt at December 31, 2017 for Duquesne Light is 4.73%. Given current rates, issuances and redemptions of debt and the amortization of certain issuance and redemption expenses during the FTY and FPFTY, the total adjusted long-term cost of debt is expected to decrease to approximately 4.60% by the end of the FPFTY.

Q. **Why is it important for the Company to maintain its creditworthiness?**

A. Duquesne Light's creditworthiness is used to determine whether, and at what cost, capital should be lent to the Company. The Company's credit ratings are an accepted indication of creditworthiness used by the capital markets. A low credit rating reduces the availability of capital and makes capital more expensive. As noted previously, a company with a non-investment grade rating may have a smaller universe of buyers for its bonds, which increases the execution risk of issuing debt and increases the interest rate. Duquesne Light has ongoing needs to access the capital markets to refinance upcoming debt maturities, fund growth capital expenditures, and to meet its pension obligations under the Pension Protection Act. The Company must be able to attract this needed capital at reasonable terms in order to fund these requirements.

Q. Please describe Duquesne Light's credit ratings.

A. Duquesne Light's current issuer or corporate credit rating is A3 and BBB as rated by Moody's and Standard & Poor's, respectively. Moody's upgraded Duquesne Light's rating on January 30, 2014 from Baa1 to A3. In its Credit Opinion released on January 30, 2018, Moody's noted that Duquesne Light's A3 rating reflects the Company's strong financial metrics and low risk, stable and predictable regulated business model. Standard and Poor's upgraded Duquesne Light's rating on March 5, 2013 from BBB- to BBB. On July 27, 2017, Standard & Poor's affirmed the BBB issuer credit rating noting the Company's excellent business risk profile and stable credit metrics. Please see Attachment DFR III-F-4c - Rating Agency Reports for a table illustrating Duquesne Light's credit ratings relative to the entire ratings table of Moody's and Standard & Poor's. Duquesne Light's current issuer credit ratings from Moody's and Standard & Poor's are at the lower end of the investment grade spectrum. A3 is four notches above non-investment grade and BBB is two notches above non-investment rating. As indicated in Attachment DFR III-F-4c - Rating Agency Reports, ratings below Baa3 for Moody's and BBB- for Standard & Poor's are considered "non-investment" grade and certain investors are not permitted or are limited in the amount they may invest in bonds with non-investment grade ratings.

Q. Do you believe that Duquesne Light's current credit ratings provide the Company with the financial flexibility it requires to meet customer needs at reasonable rates?

A. Yes, Duquesne Light's current investment grade ratings are adequate to allow the Company to efficiently access the capital markets and do so at reasonable cost. However, the Company must be able to continue to show cash flows sufficient to recover costs and earn a reasonable return in the future to maintain these ratings. Any downward pressure on the rating agency's credit metrics could result in a downgrade of the issuer rating to non-investment grade by one or both of the agencies, which, in turn, could result in higher financing costs and greater execution risk when accessing the capital markets. A one notch downgrade in credit ratings by both agencies could cost the Company an interest rate increase of approximately 25 basis points under the terms of its current Credit Agreement and 50 to 100 basis points on new long term debt issued, depending on the tenor, or time to maturity, and other relevant factors. Maintaining current credit ratings ensures lower borrowing costs for Duquesne Light. Lower borrowing costs for Duquesne Light benefits ratepayers in the form of lower rates.

Q. What impact did the recently enacted federal Tax Cuts and Jobs Act (Tax Reform) have on the Company's creditworthiness?

A. The recently passed federal Tax Reform decreased the federal corporate income tax rate from 35% to 21% and eliminated bonus depreciation. As a result, the Company was required to significantly reduce its deferred tax liabilities, with this amount reclassified to a regulatory asset at year-end 2017 and refunded to its customers over the life of the assets.

The elimination of bonus deprecation will reduce the amount of capital expenditures it may deduct as a depreciation expense, which will increase cash taxes and further decrease deferred income taxes. As a result of this significant reduction of deferred taxes, Duquesne Light will require more investor supplied capital to fund its construction program and other cash needs. The Company's credit metrics are also harmed by Tax Reform. Moody's includes deferred tax liabilities as a form of capital in the denominator of its debt to total capital metric. The reduction of deferred tax liabilities reduces the denominator of this metric, which increases the debt to total capital percentage. This is a negative to credit quality. In addition, revenue will be lower as a result of the collection of the lower tax rate, which will decrease Earnings Before Interest, Taxes, Depreciation and Amortization, or EBITDA. EBITDA is used in several metrics to assess creditworthiness such as Debt/EBITDA. Any EBITDA driven financial metric will be harmed by the lower EBITDA resulting from the lower corporate income tax rate. In response to these financial challenges caused by the new lower federal corporate income tax rate, the Company plans to reduce the percentage of debt and increase the percentage of equity in the utility's capital structure.

Q. Have the rating agencies begun to react to these negative consequences of Tax Reform on utilities creditworthiness?

A. Yes, on January 19, 2018, Moody's issued a press release stating that it revised the rating outlooks to negative from stable for 24 regulated utilities and utility holding companies; and to stable from positive for one utility holding company in the United States. The action primarily applied to companies that already had limited cushion in their rating for deterioration in financial performance, which will be incrementally negatively impacted by changes in the tax law. Duquesne Light was not included in the press release. Similarly, on January 24, 2018, S&P published an article highlighting the risks related to tax reform for the utility industry, but has not issued any outlook or ratings revisions on specific utilities at this point in time.

Q. Are the results of this rate proceeding important to the Company's ability to maintain its current credit ratings?

A. Yes, the ability to recover costs and earn a reasonable return is an important criteria used by the rating agencies in determining the Company's creditworthiness. In addition, the rating agencies assess the supportiveness of the regulatory framework in which the Company is operating, the Company's market position, and its overall financial strength. Using these criteria, Duquesne Light's small size and lack of geographic and market diversification require it to have stronger financial metrics and lower overall business risk in order to attain a similar rating as a larger, more geographically diverse utility. These risks are further exacerbated by the negative impacts noted above related to the recently passed federal income tax reform. Stronger financial metrics would include having a capital structure with higher equity capitalization and stronger cash flows compared to interest and debt levels. As I noted previously, Duquesne Light plans to modestly increase its equity ratio from December 31, 2017 levels in response to these developments. In general, the rating agencies currently view Pennsylvania as a supportive regulatory jurisdiction.

Q. **What revisions is the Company seeking related to recommendations in the Pennsylvania PUC February 2013 Focused Management and Operations Audit of Duquesne Light Company (Docket No. D-2011-2269361)?**

A. Recommendation V-1, Implementation Step 2, of the Focused Management and Operations Audit requires advance notice and explanation of future annual dividend payments to be provided to the Commission prior to making future annual dividend payments in excess of 85% of annual net income. The Company is not seeking to terminate this requirement, but rather amend the requirement to make it less susceptible to inadvertent violation.

Q. **Why is the Company seeking to amend this requirement?**

A. Under the current requirement, the Company must make all dividends prior to the end of the calendar year, which is in advance of the accounting close for year-end which occurs during the first quarter of the following year. Often there are accounting entries following year-end that can significantly impact net income for the preceding year, either positively or negatively. Typically, these accounting adjustments are non-cash true-ups of assets and liabilities. In the event that there is an accounting adjustment that negatively impacts net income following the close of a year, the Company may inadvertently violate the requirement to provide advance notice of paying a dividend for the year greater than 85% of net income for the same year given that all dividends for that year have already been paid prior to the end of the calendar year.

Q. Does Duquesne Light's dividend reporting requirement differ from other Pennsylvania utilities?

A. Yes, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company, collectively referred to as the FirstEnergy Pennsylvania Companies (FE-PA Companies), did not implement this recommendation of their Management Audit Docket Nos. (D-2013-2365991; D-2013-2365992; D-2013-2365993; and D-2013-2365994).

Q. What language does the Company recommend to replace the existing notice requirement?

A. The Company recommends replacing the language contained in Recommendation V-1, Implementation Step 2, of the Focused Management and Operations Audit as follows: The Company must provide notice and explanation to the Commission when annual dividend payments in the preceding 12 months ended March 31st exceed 85% of annual net income of the prior calendar year. With the revised language, the Company will be able to adjust its distributions in the first quarter of the following year in order to avoid inadvertently violating the advance notice requirement currently in place.

Q. Has Duquesne Light faced any challenges related to pension funding requirements as a result of market volatility and the economy in general over that past several years?

A. Yes, Duquesne Light's pension plan was more than fully funded at year-end 2007, but by year-end 2008 the funded status had deteriorated due to the sharp decline in the equity markets during that time period. The deterioration in the funded status resulted in higher required contributions to be made to the plan, as prescribed by The Pension Protection Act of 2006 ("PPA").

Q. Has the Company taken any steps to manage the funding risks presented by the pension plan?

A. Yes, the Company closed entry into its defined benefit plan for new management hires in 2007 and new union hires in 2010. The tangible benefits of closing the plan take a number of years to realize because nearly half of the participants in the pension plan that were active when the plan was closed remain active and continue to accrue benefits. The risks associated with the pension liability related to active membership will continue to decrease as these members retire or are no longer employed by Duquesne Light.

Q. Are there any additional strategies for managing the volatility of the pension's funded status and, thereby, manage the volatility of the pension funding requirements, which the Company is pursuing?

A. Yes, the Company began implementing a Liability Driven Investment ("LDI") strategy in 2012 to mitigate the volatility associated with pension plan funding. LDI is an investment strategy that focuses on managing pension assets in relation to pension liabilities. This investment strategy is not new, as insurance companies have been using it for many years under the name of Asset Liability Management. The strategy has been adopted by pension plan sponsors with a significant motivation to manage volatility of the pension funded status. Reduced volatility in pension plan funded status and pension plan funding can provide greater predictability to the Company's cash management and capital planning and ultimately provide for more stable rates for customers.

Q. How does LDI mitigate funded status and funding requirement risks of the pension plan?

A. LDI is a risk and volatility mitigation strategy, but it does not eliminate risk and volatility. The overall goal of LDI is to minimize the volatility of Plan funded status, and thus contribution volatility, by investing in long duration fixed income strategies that attempt to better match the duration of the Plan's liabilities. To see how the volatility of the funding status is reduced by LDI, consider the following example. Assume interest rates decline. The discount rate used to calculate the present value of the pension plan liabilities declines, which results in the present value of the pension plan liabilities increasing due to the discounting of future benefit payments at lower rates. Simultaneously, as interest rates decline the market value of the pension plan fixed income assets increases due to the discounting of future coupon payments at lower rates. With perfect correlation, which is unattainable, the changes in the pension plan liability would move dollar for dollar with a change in the pension plan assets and vice versa. Nevertheless, the offsetting effects of the LDI strategy on assets and liabilities should dampen variations in the funded status of the Plan.

Q. Are there any negative aspects of an LDI strategy?

A. An underfunded plan that switches to an LDI strategy could have higher funding contributions to return the plan to a fully funded status due to the plan's investments earning less. To offset this need for higher contributions, Duquesne Light has transitioned from its former return seeking strategy to an LDI strategy over time as funded status of the pension improves. This implementation plan balanced the near-term need for assets with higher expected returns with a longer-term recognition that lower funded status volatility strategies is a more suitable investment strategy for the pension plan. As funded status improves, the plan has and will continue to increase the amount of assets invested in LDI mandate investments which will help to preserve the improved funded status. At present, the plan is more than 90% funded and has approximately 60% of its pension assets in an LDI mandate. A limit on the effectiveness of LDI is that even after LDI has been fully implemented by the Company, the pension plan will still not be perfectly hedged from movement in its liabilities, as interest-rate movements do not compose all variables that impact liabilities. In addition, it is never possible to perfectly match the liability discount rate with returns from fixed income of the same duration, so all of the risks associated with funding status will never be totally eliminated.

Q. Is LDI a common investment strategy for pension plans?

A. Yes, and it is increasing in popularity, especially with companies that are seeking to manage funded status volatility in order to avoid a recurrence of the large pension funding status deteriorations that have occurred in the past.

Q. Does that conclude your testimony?

A. Yes, it does.

53.53-II	**PRIMARY STATEMENTS OF RATE BASE AND OPERATING INCOME**
53.53-II-B	**Rate Base Schedules**
53.53-II-B-4	Cash working capital
53.53-II-B-5	Bank balances
53.53-III	**RATE OF RETURN**
53.53-III-A	**Claimed Rate of Return**
53.53-III-A-1	Embedded Cost of Long-term Debt
53.53-III-A-2	Historic Test Year & 2 years prior capitalization
53.53-III-B	**Embedded Cost of Long-term Debt**
53.53-III-B-1	Detailed Schedule of claimed Long-term Debt
53.53-III-B-2	True/Economic cost if claimed
53.53-III-B-3	Bank notes
53.53-III-B-4	Short term debt
53.53-III-B-5	Long-term Debt reacquisition

53.53-III-C	**Embedded Cost of Preferred Stock**
53.53-III-C-1	Detailed Schedule of Preferred Stock
53.53-III-D	**Cost of Common Equity**
53.53-III-D-1	Support of ROE
53.53-III-D-2	Stock dividends/splits
53.53-III-D-3	Issuances of common stock
53.53-III-D-4	Utility & Parent stock offerings
53.53-III-E	**Parent-Subsidiary Relationship**
53.53-III-E-1	Capital costs of parent if claimed
53.53-III-E-2	Historic Test Year & 2 years prior capitalization of parent
53.53-III-E-3	Balance Sheet and Income Statement of parent
53.53-III-F	**General Financial Data**
53.53-III-F-3	Coverage requirements
53.53-III-F-4	Comparative financial data - 4 yrs.

Duquesne Light Company **EXHIBIT MLS-2**
Calculation of Consolidated Tax Adjustment
In Thousands (000)

	Taxable Income 2014	Taxable Income 2015	Taxable Income 2016	
Tax Loss Companies				
DQE HOLDINGS, LLC	(629)	(838)	(1,513)	
DUQUESNE LIGHT HOLDINGS, INC.	(70,917)	(67,970)	(62,715)	
DUQUESNE LIGHT COMPANY	-	-	(22,964)	
Total Tax Loss	(71,546)	(68,808)	(87,192)	
Tax Positive Companies				
DUQUESNE LIGHT COMPANY	92,932	116,214		
MONONGAHELA LIGHT AND POWER	817	889	837	
DUQUESNE FIBER COMPANY	1,095	360	541	
DES CORPORATE SERVICES, INC.	(4)	2	10	
DQE ENTERPRISES, INC.	59	0	259	
DQE CAPITAL CORPORATION	(3)	(4)	1	
DQE SYSTEMS, INC.	6,810	11,700	10,421	
Total Taxable Income	101,707	129,162	12,069	
Total Consolidated Income/(Loss)	30,161	60,353	(75,122)	
% of Total	91.37%	89.98%	0.00%	
Total Allocated Tax Loss	(65,373)	(61,911)	-	(42,428)
Distribution allocation				61.680% [a]
Loss allocated to Distribution				(26,170)
Federal Tax rate				21.0%
Consolidated Tax Adjustment				(5,496)

[a] Source: Mr. Gorman testimony, Statement #14, Jurisdictional Separation Study Exhibit 6-8A, JSS Factors - FedTax_Pres Distribution percentage

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3000124

Duquesne Light Company

Statement No. 14

Direct Testimony of Howard S. Gorman

Dated: March 28, 2018

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your name and occupation.

A. My name is Howard Gorman. I am the President of HSG Group, Inc., a consulting firm that I started in 2010.

Q. Please summarize your educational background and professional experience.

A. My educational background, professional experience and summary of testimony are outlined in Attachment A.

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

A. I am testifying on behalf of Duquesne Light Company ("Duquesne Light" or "Company") in this proceeding before the Pennsylvania Public Utility Commission ("Commission").

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

A. My testimony describes the Jurisdictional Separation Studies (each a "JSS") and the unbundled, Allocated Cost of Service Study ("ACOS") I have prepared for Duquesne Light with the Commission's Data Filing Requirements ("DFR"), specifically DFR IV-E-1.

The purpose of the JSS is to separate Duquesne Light's total annual revenue requirement among the following:

- Supply service,
- Portion subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), i.e., the transmission revenue requirement,
- Borough of Pitcairn, which is discussed below, and
- Portion subject to the jurisdiction of the Commission, i.e., the distribution revenue requirement.

In my testimony, "jurisdiction" means jurisdiction, or regulation, only as to rates. Separate Jurisdictional Separation Studies were prepared for the year ended December 31, 2017 (Historic Test Year or HTY), for the year ended December 31, 2018 (Future Test Year or FTY) and for the year ended December 31, 2019 on a fully projected basis (Fully Projected Future Test Year or FPFTY).

The purpose of the ACOS is to assign, on a cost-causation basis, Duquesne Light's distribution revenue requirement (determined in the JSS) among the rate classes in its Tariff. The ACOS was prepared for the FPFTY.

Q. Which study was used in revenue allocation and rate design?

A. The ACOS for the FPFTY, which assigns the distribution revenue requirement among the rate classes in the Tariff, was the basis for revenue allocation and rate design. In the FPFTY ACOS, the revenue requirement resulting from the ACOS for each rate class was compared to the revenue produced by the present Tariff rates, and this information was used for guidance by Duquesne Light in designing the rates it is proposing in this proceeding.

The HTY JSS and the FTY JSS were not used in determining the distribution portion of the total revenue requirement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

<u>Section I</u> (this section)- Introduction and purpose of testimony

<u>Section II</u>- Overview of ACOS

<u>Section III</u>- Identification and discussion of exhibits included with my testimony

<u>Section IV</u>- Jurisdictional Separation Studies

<u>Section V</u>- Allocated Cost of Service Study

Section VI- Development of Allocators for FPFTY ACOS

II. OVERVIEW OF JURISDICTIONAL SEPARATION STUDIES AND ALLOCATED CLASS COST OF SERVICE STUDIES

Q. Please describe the purpose of the JSS and how it is prepared.

A. The Company's filing in this proceeding is based on the investments made and to be made, and costs to be incurred, to provide distribution delivery service to its Pennsylvania jurisdictional customers. Company witness Mr. O'Brien has determined the Company's total revenue requirement for the FPFTY (Duquesne Light Exhibit No. 2). The purpose of the JSS is to separate the total revenue requirement, after first eliminating revenues and costs to provide supply service, between the portion subject to the jurisdiction of the FERC, i.e., transmission revenue requirement, and the portion subject to the jurisdiction of the Commission, i.e., the distribution revenue requirement.

In addition, a portion of the total revenue requirement is assigned or allocated to the Borough of Pitcairn, which I discuss below.

In performing the JSS, each component of the total annual revenue requirement, including plant and other rate base items, operating expenses, depreciation and taxes, is analyzed, in order to directly assign or to allocate that item between transmission and distribution. The distribution revenue requirement amount determined in the JSS, is then allocated among the rate classes in the ACOS.

Q. Please discuss how distribution service provided to the Borough of Pitcairn is reflected in the JSS.

A. The Borough of Pitcairn was historically a "sales for resale" customer of the Company and subject to the jurisdiction of the FERC. Subsequent to electric restructuring in Pennsylvania, Pitcairn now purchases its energy requirements from a wholesale provider, receives transmission service under the PJM Open Access Transmission Tariff and uses delivery service provided by the Company at 23 kV. The Company's distribution Tariff does not provide for this service (to a wholesale customer), therefore the costs associated with providing the service are removed in determining the distribution revenue requirement. To accomplish this, Pitcairn is represented as a separate jurisdictional column in the JSS.

Q. Please describe the purpose of the ACOS and how it is prepared.

A. As discussed above, the Company's filing is based on its investments and costs incurred to provide distribution delivery service to its Pennsylvania jurisdictional customers. The purpose of the ACOS is to directly assign or allocate among the rate classes each component of the distribution revenue requirement, including plant and other rate base items, operating expenses, depreciation and taxes, in order to determine the cost of providing service to each rate class. Each component of the total revenue requirement must be analyzed and assigned or allocated among the rate classes, so that the utility can establish rates that, based on assumptions such as sales volumes and the number of customers, provide it with a fair opportunity to recover its costs and to earn an appropriate return.

A three-step process is traditionally used to analyze each component of the revenue requirement. The first step is Functionalization of each component; for Duquesne Light these functions are Primary Distribution, Secondary Distribution and Billing.

The second step is Classification of each functionalized component as Demand, Energy or Customer.

The final step, Class allocation, is the allocation of each functionalized, classified component among the rate classes.

The results of the ACOS, that is, the distribution revenue requirement determined for each rate class, are compared to the revenue produced by the present Tariff rates; this information was used by Duquesne Light for guidance in designing the rates it is proposing in this proceeding.

Q. What is meant by "direct assignment."

A. The term "direct assignment" means identifying plant investments or costs incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation of serving particular customers or rate classes. Therefore, direct assignments should be used whenever possible.

Q. What are External allocators and Internal allocators.

A. Two types of allocators are used in performing a JSS or ACOS: external allocators and internal allocators. *External allocators* are based on special studies derived from the utility's accounting, operating and other records. For example, the allocator "NCP-Primary" measures each class' peak, not necessarily coincident with the system peak, and is used to allocate certain demand costs. Other examples of external allocators are the number of customers in each rate class, meter costs for each rate class and historical bad debt experience for each rate class.

Internal allocators are based on some combination of external allocators, previously directly assigned costs and other internal allocators. For example, the allocators for property insurance costs are based on plant investments; it is necessary to allocate plant investments before property insurance costs can be allocated. Both external and internal allocators are used in each of the functionalization, classification and allocation steps.

Q. What is the FPFTY total revenue requirement?

A. The FPFTY total revenue requirement was determined by Duquesne Light witness O'Brien to be $931.6 million, if the distribution rate of return of 8.06% is applied to the entire Company. The exhibits that I am sponsoring show, by FERC account, the composition of the total revenue requirement for the JSS, and the composition of the distribution revenue requirement for the ACOS.

Q. What are the revenue at present rates in the FTY and the FPFTY?

A. The supply, transmission and distribution revenue at present rates for the FTY and the FPFTY were computed by Duquesne Light witness Ogden, as shown on Attachment DFR IV-A Fully Projected Future (page 2, columns I, J and K). This information was used in the JSS and the ACOS; the distribution revenue at present rates was also used in the ACOS.

Q. What rate classes are represented in the ACOS?

A. The ACOS includes the following rate classes:

Residential (RS)
Residential Heating (RH)
Residential Add-on Heat (RA)
General Service (GS No demand)
General Medium<25 (GM<25)
General Medium>25 (GM>25)
General Medium Heating<25 (GMH<25)
General Medium Heating>25 (GMH>25)
General Large (GL)
General Large Heating (GLH)
Large (L)
High-Voltage Power Service (HVPS)
Street Lighting Energy (SLE)
Street Lighting (SLM)
Unmetered Service (UMS)

Q. Are these the rate classes that are currently in the Tariff?

A. Yes, with the following explanations and exceptions:

1. The current Tariff class GSGM includes a separate set of rates for each of the following customer load profiles: a) GS No Demand; b) GM Demand under 25 kW (GM<25) and c) GM Demand 25 kW and greater (GM>25). Because there is a different set of rates for each customer load profile, they are represented separately in the ACOS.
2. The current Tariff class GMH was split into two groups in the ACOS, because they are represented as separate customer load profiles in the Company's supply tariff: a) GMH Demand under 25 kW (GMH<25) and b) GMH Demand 25 kW and greater (GMH<25).
3. The ACOS rate class group Street Lighting (SLM) comprises four Tariff rate classes: Street Lighting Municipal (SLM), Street Lighting Highway (SLH), Private Area Lighting (PAL) and Architectural Lighting (AL).

SLM, SLH and PAL have the same load and usage profiles. AL is very small and was included in the group for convenience. The current Lighting classes will remain separate classes in the Tariff.

4. Customers that presently take service under rate L are assumed to migrate to rate HVPS, due to proposed changes in the tariff that will permit these customers to do so.

Q. Please describe the functions that are included in Distribution.

A. Distribution comprises the functions Primary Distribution, Secondary Distribution and Billing. The distribution system, Primary Distribution and Secondary Distribution, moves power from distribution substations to the Company's customers. The distribution system includes operating facilities rated below 69kV; *Primary Distribution* includes assets rated 4kV through 23kV and *Secondary Distribution* includes all other distribution assets related to moving power to customers, including service drops and excluding meters. *Billing* includes metering, billing and customer accounting and service.

Q. Did you prepare the Company's JSS and ACOS in its most prior recent base rate case before this Commission, Docket 2013-2372129?

A. Yes, I prepared the Company's JSS and ACOS in that proceeding.

Q. Did you use the same methodology to prepare the JSS and ACOS that you are presenting today, as in Docket 2013-2372129?

A. Yes, the same methodology was used.

III. IDENTIFICATION AND DESCRIPTION OF EXHIBITS

Q. Please identify the exhibits that are included with your testimony.

A. My testimony includes the following Exhibits:

<u>JSS for the FPFTY and the HTY</u>

Exhibit 6-1	JSS for the FPFTY
Exhibit 6-1A	JSS for the HTY
Exhibit 6-1B	JSS for the FTY

<u>ACOS for the FPFTY- Distribution revenue requirement</u>

Exhibit 6-2	Summary of revenue requirement for each rate class
Exhibit 6-3	Revenue requirement for each rate class, functional classification
Exhibit 6-4	Customer charge costs- Summary
Exhibit 6-4A	Customer charge costs- RS
Exhibit 6-4B	Customer charge costs- GS
Exhibit 6-4C	Customer charge costs- GM<25
Exhibit 6-4D	Customer charge costs- GM>25
Exhibit 6-4E	Customer charge costs- GMH
Exhibit 6-4F	Customer charge costs- L
Exhibit 6-4G	Transformer costs
Exhibit 6-4H	Rider 16- Back-up Power
Exhibit 6-5	Functionalization
Exhibit 6-6	Classification for Secondary Distribution function
Exhibit 6-7	Revenue requirement for each rate class, by account
Exhibit 6-7A	Class allocation - Primary Distribution Demand
Exhibit 6-7B	Class allocation- Secondary Distribution Demand
Exhibit 6-7C	Class allocation - Secondary Distribution Customer
Exhibit 6-7D	Class allocation - Billing customer
Exhibit 6-8	Assignment or Allocator Used for Each Account
Exhibit 6-8A	Allocator values - JSS
Exhibit 6-8B	Allocator values - Functionalization
Exhibit 6-8C	Allocator values- Classification
Exhibit 6-8D	Allocator values - Class allocation
Exhibit 6-9	Development of external allocator values
Exhibit 6-10	Distribution ROR at Proposed Revenue Allocation
Exhibit 6-11	SL- Distribution Component

Q. Please describe Exhibits 6-1, 6-1A and 6-1B.

A. *Exhibit 6-1* presents the jurisdictional separation for the FPFTY. The exhibit shows each item in the total revenue requirement, the direct assignment or allocator selected for that item, and the result of the allocation (or assignment) among supply, transmission, Pitcairn and distribution.

The components of the revenue requirement are: plant and other rate base (lines 1-76), operating expenses (lines 77-136), depreciation expense (lines 137-157) and taxes (lines 158-175). Revenues (lines 178-187) are compared to total expenses (line 176, also line 188) to compute net income at present rates (line 189, also line 207) and return on rate base (line 209).

The distribution revenue required to produce a rate of return of 8.06% in the FPFTY is computed on lines 211-227, and the difference between the revenue requirement and revenue at present rates is shown on line 230.

The distribution revenue requirement for the FPFTY is $587.6 million, an increase of $81.6 million over revenue at present rates. This increase in revenue is achieved by increase in base rates revenue of $137.8 million offset by elimination of certain surcharges totaling $56.2 million, such as Smart Meter and DSIC, which have been rolled into base rates.

Exhibit 6-1A and Exhibit 6-1B present the JSS for the HTY and the FTY, respectively. The line references are the same as for Exhibit 6-1.

Q. Please describe Exhibit 6-2.

A. *Exhibit 6-2* summarizes the results of the ACOS for the FPFTY. The exhibit presents, for each rate class, the return on rate base at present rates for the FPFTY, and the FPFTY revenue requirement assuming each class provides the rate of return on rate base requested by the Company in this proceeding, 8.06%.

The exhibit shows revenue at present rates (lines 1-4), expenses (line 6), net income (line 7) and rate base (line 9) for each rate class, and computes return on rate base at present rates (line 11). The revenue requirement for each rate class to produce a rate of return of 8.06% is on line 13, and the corresponding net income and rate of return for each rate class are computed on lines 15-25. The exhibit computes the increase or decrease in distribution revenue for each class to produce the 8.06% return (line 27), and the percentage this represents (line 28).

The exhibit demonstrates that to produce the return on rate base of 8.06% an increase in distribution revenue of $81.6 million, or 13.119%, is needed.

Q. Please describe Exhibit 6-3.

A. *Exhibit 6-3* presents the results of the ACOS, summarized by functional classification (primary distribution, secondary distribution- demand related, secondary distribution- customer related and billing) and also shows unitized revenue requirements. This information is useful in rate design.

Q. Please describe Exhibits 6-4 through 6-4F.

A. *Exhibits 6-4 through 6-4F* compute the costs to be considered in determining the customer charge, based on PUC precedent, for the following rate classes: RS (Exhibit 6-4A); GS (Exhibit 6-4B), GM<25 (Exhibit 6-4C); GM>25 (Exhibit 6-

4D). GMH (Exhibit 6-4E); and L (Exhibit 6-4F), with a summary on Exhibit 6-4. The amounts on these exhibits are based on the results of the ACOS.

Q. Please describe Exhibit 6-4G.

A. *Exhibit 6-4G* computes the credit for untransformed service.

Q. Please describe Exhibit 6-4H.

A. *Exhibit 6-4H* computes the Company's proposed rate for Back-up Service, which includes only direct costs to provide service. The direct costs that are included are return on (including income tax expense) Distribution Plant and General Plant less depreciation reserve and other rate base items, O&M costs, customer accounts expense, certain A&G costs associated with labor and property, and depreciation expense associated with the plant referred to above. This calculation reflects more closely the costs the Company incurs to provide Back-up service to customers with their own generation who have contracted with the Company for the service.

Q. Please describe Exhibit 6-5.

A. *Exhibit 6-5* shows how each component of the FPFTY revenue requirement has been functionalized in this study, among one or more of the following functions: Primary Distribution, Secondary Distribution and Billing. The exhibit shows the allocator selected for each component, and the result of the allocation. The line references are the same as for Exhibit 6-1.

Q. Please describe Exhibit 6-6.

A. *Exhibit 6-6* shows how each component of the Secondary Distribution function has been classified to either Demand or Customer. Classification schedules are not needed for Primary Distribution because it is classified 100% to Demand or for Billing because it is classified 100% to Customer. The exhibit shows the classification allocator selected for each component, and the result of the allocation. The line references are the same as for Exhibit 6-1.

Q. Please describe Exhibits 6-7 through 6-7D.

A. *Exhibits 6-7 through 6-7D* shows how each component of the functionalized, classified costs has been allocated among the rate classes. This includes Primary Distribution Demand (Exhibit 6-7A), Secondary Distribution Demand (Exhibit 6-7B), Secondary Distribution Customer (Exhibit 6-7C) and Billing Customer (Exhibit 6-7D). The information is summarized on Exhibit6-7. The Balance totals for Primary Distribution Demand and Billing Customer are from Exhibit 6-5 (Functionalization), and the balance totals for Secondary Distribution Demand and Secondary Distribution Customer are from Exhibit 6-6 (Classification- Secondary distribution). Each exhibit shows the allocation factor selected to allocate each component among the rate classes, and the result of the allocation. The line references are the same as for Exhibit 6-1.

Q. Please describe Exhibits 6-8 through 6-8D.

A. *Exhibit 6-8* shows the allocator used for each account. The exhibit includes columns for JSS, Functionalization; Classification (Secondary Distribution) and Class Allocation (Primary Distribution Demand, Secondary Distribution Demand, Secondary Distribution Customer and Billing Customer).

Exhibits 6-8A through 6-8D show the allocator values for, respectively, JSS, Functionalization, Classification and Class Allocation.

Q. Please describe Exhibit 6-9.

A. *Exhibit 6-9* shows the development of the external allocator values. I will discuss each exhibit in detail later in my testimony.

IV. JURISDICTIONAL SEPARATION STUDIES

Q. Referring to Exhibit 6-1, the JSS for the FPFTY, how did you determine the appropriate direct assignment or allocator for the jurisdictional separation of each item in the total revenue requirement?

A. Selection of the appropriate direct assignment or allocator for the jurisdictional separation of each component of the total revenue requirement was based on careful consideration of cost causality, as well as prior Duquesne Light methodology, Commission precedent and utility practice as stated in the Electric Utility Cost Allocation Manual (January 1992) of the National Association Of Regulatory Utility Commissioners ("NARUC Manual"). Cost causality means the cause and effect relationships between customer requirements, load profiles and usage characteristics on one hand, and the costs incurred to serve those requirements on the other hand.

Q. Did you use the same allocator for each account as was used in the JSS presented in Docket R-2013-2372129?

A. Yes.

Q. How did you directly assign or allocate the components of rate base for the purpose of jurisdictional separation?

A. *Intangible assets* is primarily software, and the components of this asset were allocated according to their use for customer-related activities, metering-related and other activities.

Transmission plant and *distribution plant* were directly assigned to their respective functions based on the FERC accounts, except for the distribution assets that serve Pitcairn, which were directly assigned to it. The Company's FERC accounts reflect the 7-factor test (separating Transmission and Distribution assets) completed in connection with its filing in Docket R-00061346.

General plant was allocated based on the labor content of operating and maintenance ("O&M") accounts.

Depreciation reserve followed the plant and asset accounts to which it related.

Other rate base items were provided by function (Accumulated deferred income tax, Materials & supplies) or were directly assigned (Customer deposits) or allocated (Cash working capital, Capitalized pension).

Q. How did you directly assign or allocate costs for the purpose of jurisdictional separation?

A. *Supply costs* and *Transmission O&M* were directly assigned to their respective functions. *Distribution O&M* was directly assigned to the distribution function, except for a small portion that was allocated to Pitcairn based on its share of the distribution assets that serve Pitcairn. Customer accounts and customer service costs were directly assigned to Distribution.

Most *Administrative & general* costs were allocated based on labor content of O&M accounts. Customer-related items were directly assigned to distribution; and property insurance was allocated based on plant cost.

Depreciation expense followed the plant or assets accounts to which it related.

Taxes were allocated based on labor (payroll taxes), plant cost (PURPA tax), revenue subject to Pennsylvania gross receipts tax or taxable income (Pennsylvania and Federal income tax).

Q. How did you directly assign or allocate revenue for the purpose of jurisdictional separation?

A. Each revenue component was directly assigned to one jurisdictional column. *Supply* and *Transmission revenue* were directly assigned to their respective functions; these amounts include miscellaneous revenues directly identified to those functions. *Distribution revenue*, including delivery revenue and other revenues included in this proceeding, were directly assigned to distribution.

Q. How did you compute the Pennsylvania jurisdictional distribution revenue requirement?

A. The Pennsylvania jurisdictional distribution revenue requirement is computed on lines 211-227. It is the amount required to recover all jurisdictional costs, and to provide an after-tax return on jurisdictional rate base of 8.06%.

Q. Do the JSS for the HTY, presented in Exhibit 6-1A, and the JSS for the FTY, presented in Exhibit 6-1B, compute the respective jurisdictional revenue requirement in the same manner as the JSS for the FPFTY?

A. Yes.

V. ALLOCATED COST OF SERVICE (ACOS) STUDY

Q. Referring to Exhibits 6-2 through 6-8D, the ACOS for the FPFTY, how did you determine the appropriate allocators for functionalizing, classifying and allocating the components of the distribution revenue requirement?

A. Selection of the appropriate approach for functionalizing, classifying and allocating each component of the revenue requirement was based on careful consideration of cost causality, as well as prior Duquesne Light methodology, Commission precedent and utility practice as stated in the NARUC Manual. Cost causality means the cause and effect relationships between customer requirements, load profiles and usage characteristics on one hand, and the costs incurred to serve those requirements on the other hand.

Functionalization

Q. Please describe the functionalization step in preparing the ACOS.

A. In the functionalization step, costs are separated by the utility's basic service functions; for Duquesne Light, these are Primary Distribution, Secondary Distribution and Billing. There are separate functions for Primary Distribution and Secondary Distribution because some customers take service at Primary voltages; therefore it is necessary to separate the assets so that only the customers that use each portion of the system are allocated the costs attributed to that portion. Billing refers to activities starting at the meter on the customer's premises, and includes metering activities and customer care, as well as activities intrinsic to the utility function.

Q. Were any assets refunctionalized?

A. For the most part, functionalization follows costs as recorded in the FERC Uniform System of Accounts. However, some accounts were split into more than one cost component. For example, a portion of Station Equipment (Account 362) representing assets used to serve customers in the downtown network was split out in order to allocate the cost among the appropriate rate classes. Underground Conduits (Account 366) and Underground Conductors (Account 367) were split into separate components representing three different portions of the underground system- Radial; Network; and Underground Residential Development ("URD"), based on Company engineering estimates and judgments. Exhibit 6-5 shows the amount for each FERC account and other component included in the revenue requirement (in the column "Balance"), the functional allocator used for each (in the column "Allocator"), and the amounts assigned to each function (in the columns "Primary Distribution" and "Secondary Distribution" and "Billing"). The revenue requirement for each function is shown on line 227. Exhibit 6-8B shows the values for each functional allocator.

Q. How were assets functionalized between the Primary Distribution and Secondary Distribution functions?

A. Duquesne Light's Primary Distribution system operates at voltages of 4kV up to 23kV. In recent years, Duquesne Light has converted much of the 4kV system to 23kV, and has expanded the 23kV portion of the system.

Structures (Account 361) and Station Equipment (Account 362) are part of the Primary Distribution system.

Overhead Conductors and Devices (Account 365) was functionalized between Primary Distribution and Secondary Distribution based on a review of purchases over the period 1999-2016.

Poles, Towers and Fixtures (Account 364) were allocated proportionately to the Overhead Conductors and Devices they support.

Each component (Radial, Network, and URD) of Underground Conduits (Account 366) and Underground Conductors (Account 367) was functionalized between Primary Distribution and Secondary Distribution based on a review of purchases over the period 1999-2016.

Line Transformers (Account 368) has subaccounts for Overhead, Radial, Network and URD. Almost all transformers are part of the Secondary Distribution system, except for some of the larger Overhead transformers which are part of the Primary Distribution system.

Services (Account 369) are also part of the Secondary Distribution system, and Meters (Account 370) are part of the Billing function. Street Lighting Equipment (Account 373) is part of the Secondary Distribution system.

Exhibit 6-9B summarizes the results of the functionalization of distribution assets (accounts 360-373 in the USA) between Primary Distribution and Secondary distribution. Exhibit 6-9C shows the supporting calculations.

Classification

Q. Please describe the classification step in preparing the ACOS.

A. In the classification step, the previously functionalized accounts are separated into Customer, Energy or Demand, according to the system design or operating characteristics that cause them to be incurred.

Customer-related costs are incurred to attach a customer to the distribution system, to operate and maintain the Company's distribution plant, to meter usage, and to maintain the customer's account. Customer-related costs are primarily a function of the number of customers served and continue to be incurred whether or not a particular customer uses any electricity, and typically do not vary with usage or load profile. They include capital costs associated with the customer portion of the distribution system, services and meters, and operating costs such as customer service, field service, billing and accounting.

Energy-related costs would vary with the amount of electricity sold to or delivered to customers. In the ACOS, no costs or rate base were allocated on the basis of energy (MWh).

Demand-, or capacity-, related costs are associated with plant that is designed, constructed and operated to meet system peak demand or non-coincident class peak demand.

Q. How were assets and costs classified?

A. Most assets and costs fit into one of the three classifications, but some are split between Demand and Customer based upon special studies or based on the classification of related assets or other related costs.

On the Duquesne Light system, Primary Distribution plant is designed to meet localized peak demands; these functions are classified 100% to Demand. The Billing function is classified 100% to Customer.

Secondary Distribution plant has two purposes- to connect the customer in order to carry electricity to the customer regardless of use, and to meet localized peak demands. Most Secondary Distribution assets (i.e., Overhead Conductors; Underground Conduits; Underground Conductor; and Line Transformers) were classified as Demand or Customer using a Minimum System approach. In the Minimum System approach, for each Secondary Distribution asset class, the Minimum Size Ratio was computed, equal to the ratio of x) the cost of the minimum size of that asset necessary to provide reliable distribution service to y) the average cost of that asset. The utility must install the minimum size asset, and incur the cost for that asset, simply to connect the customer, regardless of usage or load profile, and the cost of the minimum size asset is not related to usage (kWh) or peak demand. Therefore the portion of total asset cost represented by the Minimum

System Ratio is classified as Customer-related. The balance of each Secondary Distribution asset account is classified as Demand-related.

Investments in Poles, Towers and Fixtures are classified as Customer proportionately to Overhead Conductors. Services, Meters and Meter Communications Equipment, and Street Lighting assets are classified as Customer. Secondary Distribution costs that are related to particular assets were classified in proportion to those assets. For example, Maintenance of Overhead Lines (Account 593) was classified using the same classification allocator as Overhead Lines. Other costs, such as general plant and administrative and general expenses, are related to more than one function. Therefore each item in Other costs was analyzed to determine the appropriate classification allocator.

Exhibit 6-6 shows the classification of each component in the Secondary Distribution function by FERC account. Primary Distribution is classified 100% to Demand and Billing is classified 100% to Customer, so there is no need to show the classification by FERC account. Exhibit 6-8C shows the values for each classification allocator.

Q. Please describe the Minimum System approach used in the ACOS.

A. The Minimum System approach was used for Secondary system Line Transformers, Overhead Conductors and Underground Conductors.

For *Line Transformers*, Duquesne Light provided detailed historical records by size and by cost for each of Overhead transformers (Account 368.1), Underground Radial transformers (Account 368.3), Underground Network transformers (Account 368.5) and URD transformers (Account 368.7). For each of these accounts, the Minimum System Ratio, equal to the ratio of (x) the cost of the minimum size transformer to (y) the average cost of all transformers, was computed, using recent costs. The Minimum System Ratio represents the Customer component of cost, and is mathematically equal to dividing (a) what the account balance would be if all units in the account were equivalent to the minimum size unit, by (b) the total account balance.

For *Overhead Conductors* and *Underground Conductors*, historical information by size and by cost was not available. For each item, the ratio of (x) the estimated current cost if the minimum size (voltage rated) unit would be installed to (y) the estimated average current cost of all units, was computed; this ratio equals the Customer component of cost. Separate minimum size computations were made for Overhead Conductors and each component of Underground Conductors (Radial, Network and URD).

Exhibit 6-9B summarizes the classification of distribution assets (Accounts 360-373 in the FERC USA) based on the Minimum System Study, and Exhibit 6-9C shows the supporting calculations.

The demand-classified portions of certain of these assets were adjusted to reflect the ability of the minimum size system to carry a portion of peak load (Peak Load Carrying Capacity, or "PLCC"). I will discuss the PLCC adjustment below.

Q. Please describe the class allocation step in preparing the ACOS.

A. In the class allocation step, the functionalized, classified costs are allocated among the rate classes, based on causal relationships. These relationships are determined by analyzing the Company's system design and operations, its accounting records and its system and customer load data. Based on those analyses, direct assignments of costs, as well as cost allocators, can be chosen for each asset and cost.

Q. How were the components of the rate base in the Distribution revenue requirement allocated among the rate classes in the ACOS?

A. Demand-related assets, or the demand-related portions of assets, were allocated based on the appropriate class non-coincident peak ("NCP") allocator. Exhibit 6-9D identifies the demand allocator selected for the demand component of each type of asset (Distribution Substations; Poles, Tower and Fixtures and Overheard Conductors; Underground Conduits and Underground Conductors; and Line Transformers). Separate NCP allocators were developed for the different configurations of the distribution system, as described in Exhibit 6-9D.

Customer-related assets, or the customer-related portions, were allocated based on the number of customers that use the asset, or special studies for Services (Account 369- based on the comparative costs of installing residential and commercial services), Meters (Account 370-based on the number and types of meters used by each rate class) and related assets.

The total Meter cost in Account 370, reflects the installed costs of meters and costs of the Automated Metering Infrastructure ("AMI"). The installed costs of meters was allocated based on whether the class uses predominantly single-phase meters (residential classes and GS), both single phase and poly-phase meters (GM<25 and GMH<25) or predominantly poly-phase meters (all other classes except Lighting and unmetered). Similarly, AMI costs were allocated based on whether the class uses predominantly single-phase meters, both single phase and poly-phase meters or predominantly poly-phase meters. In addition, the portions of Intangible Assets and Other Plant relating to AMI were allocated in the same manner. This is consistent with the methodology used for the current Smart Meter surcharge pursuant to the Commission's Order in Docket M-2009-2123948.

General plant was allocated based on the labor content of O&M accounts.

Depreciation reserve and Accumulated deferred income tax followed the plant and asset accounts to which they related.

Cash Working Capital, Materials & supplies and Capitalized pension were allocated using internal allocators, and Customer deposits was directly assigned.

Each of Exhibits 6-7A though 6-7D shows the allocator used for each component of the rate base functionally classified as Primary Demand, Secondary Demand, Secondary Customer and Billing Customer, respectively.

Q. How were costs in the Distribution revenue requirement allocated among the rate classes in the ACOS?

A. The demand-related and customer-related components of O&M costs followed the allocation of the particular assets to which they related. For example, Maintenance of Overhead Lines (Account 593) was allocated using the same allocators as the plant asset Overhead Conductors, (Account 365) and Maintenance of Underground Lines (Account 594) was allocated in proportion to the total of the plant assets Underground Lines- Radial, Network and URD (Account 367). Special studies were used to develop the allocators for Meter Expenses (Account 586) and Maintenance of Meters (Account 597).

Miscellaneous Distribution Expenses (Account 588) and Maintenance of Miscellaneous Plant (Account 599) were functionalized, classified and allocated in proportion to distribution plant.

Customer accounts and services (Accounts 901-908) were analyzed to determine the activities charged to each account, and each activity was allocated based on the appropriate causal relationship. The analysis is shown on Exhibit 6-9I.

Administrative and general expenses (Accounts 920-935) were allocated primarily based on the labor content of OM accounts.

Depreciation expense followed the plant accounts to which it related.

Payroll taxes were allocated based on labor; PURPA tax was allocated based on plant cost, Pennsylvania gross receipts tax was allocated based on revenue subject to the tax; and income tax expense was allocated based on pretax income.

Each of Exhibits 6-7A though 6-7D shows the allocator used for each component of costs functionally classified as Primary Demand, Secondary Demand, Secondary Customer and Billing Customer, respectively.

Q. How was revenue at present rates applicable to the Distribution revenue requirement allocated among the rate classes in the ACOS?

A. Distribution delivery revenue was directly assigned based on Attachment DFR IV-A Fully Projected Future (page 2, columns E through H, which includes the Smart Meter, DSIC, STAS and RME charges that are being rolled into base rates, and the adjustments for Energy Efficiency and revenue annualization). Forfeited discounts revenue was allocated based on historical net write-offs. Rent from Electric Property was allocated in the same manner as Overhead Conductors. Miscellaneous Service was allocated based on Distribution delivery revenue.

Q. How did you develop the revenue requirement for each class?

A. The revenue requirements for each class are computed in the same manner as that used by witness Mr. O'Brien to compute the overall revenue requirement for the FPFTY, and that I used to calculate the Pennsylvania jurisdictional (i.e., Distribution) revenue requirement. Class revenue requirements are the sum of each class' allocated operating expenses, depreciation expense, general taxes, required return and the income tax and gross receipts tax. The Distribution service revenue requirement for each rate class are shown on Exhibit6-7, line 227, and also on Exhibit 6-2, line 13.

Q. How did you determine the revenue deficiency for each rate class?

A. The class revenue deficiency is computed by comparing the revenue requirements for each class to the revenue that is forecast at present rates for that class.

VI. DEVELOPMENT OF ALLOCATORS FOR ACOS

Q. How were the allocators used in the ACOS developed?

A. Exhibit 6-9 shows the development of the external allocators used in the ACOS. Exhibit 6-9 includes Exhibits 6-9A through 6-9K.

Q. Please describe Exhibit 6-9.

A. Exhibit 6-9A shows the allocator values for each external class allocator. The allocator values are developed in the remaining pages of Exhibit 6-9.

Q. Please describe Exhibit 6-9B and Exhibit 6-9C.

A. Exhibit 6-9B summarizes the results of the functionalization of distribution assets (accounts 360-373 in the FERC USA) between Primary Distribution and Secondary Distribution and the Minimum System Study.

Exhibit 6-9C shows the calculations for the functionalization of distribution assets between Primary Distribution and Secondary Distribution and the Minimum System Study.

Q. Please describe Exhibit 6-9D, Exhibit 6-9E and Exhibit 6-9E-1.

A. Exhibit 6-9D identifies the demand allocator selected for the demand component of each type of asset (Distribution Substations; Poles, Tower and Fixtures and Overheard Conductors; Underground Conduits and Underground Conductors; and Line Transformers). Separate allocators were developed for the Radial, Network and URD components of Underground Conduits and Underground Conductors and Line Transformers. Exhibit 6-9D also discusses how each demand allocator was developed.

Exhibit 6-9E presents the computation of the demand allocators, by applying the approach discussed in Exhibit 6-9D. Exhibit 6-9E-1 presents the PLCC adjustment.

Q. Please discuss the PLCC adjustment.

A. The minimum size components developed for the Secondary Distribution system have the ability to carry a portion of peak load (Peak Load Carrying Capacity, or "PLCC"). The PLCC of certain of these assets was removed in computing the allocator for the Secondary-Demand classified portion of those assets.

For example, the minimum system for OH Transformers (based on the 25 kVA minimum size component) have capacity equal to 3.2 kW per customer; therefore in computing the allocator NCP-Secondary-Xfmr which is used for the demand component of OH Transformers, peak demands above 3.2 kW per customer is deducted from the for each class.

The PLCC adjustment was made for OH Transformers and Radial Transformers, comprising 64% of Secondary Demand plant; the effect on the results of the ACOS was insignificant. The PLCC adjustment was not made for other Secondary Demand plant because the detailed information needed was not readily available and effect on the results of the ACOS would not be justified.

Q. Please describe Exhibit 6-9F.

A. Exhibit 6-9F presents the values for revenue and physical (MWh) allocators, and number of customers, as shown on Attachment DFR IV-A Fully Projected Future (page 1, columns C and D).

Q. Please describe Exhibit 6-9G.

A. Exhibit 6-9G presents the calculation of service costs based on current installed costs for typical residential and commercial services.

Q. Please describe Exhibit 6-9H.

A. Exhibit 6-9H presents the calculation of the meter cost allocator, the AMI cost allocator and related allocators, based on the types of meters installed, meter costs and other information.

Q. Please describe Exhibit 6-9I.

A. Exhibit 6-9I presents the allocation of Customer Accounts Supervision (account 901) and Customer Records and Collections (account 903), based on analyses of activities charged to each account. It includes a supporting analysis of Call Center activity.

Q. Please describe Exhibit 6-9J.

A. Exhibit 6-9J allocates among the rate classes Write-off Dollars, based on historical information.

Q. Please describe Exhibit 6-9K.

A. Exhibit 6-9K presents Customer deposits by rate class.

VII. RATES OF RETURN AT PROPOSED REVENUE ALLOCATION

Q. Please describe Exhibit 6-10.

A. *Exhibit 6-10* computes the Distribution Rates of Return for each rate class based on the revenue allocation proposed by Mr. Ogden, as well as the progress towards unity for each rate class. The revenue that would be produced under proposed rates for the FPFTY was computed by Mr. Ogden, as shown on Attachment DFR IV-A Fully Projected Future (page 6).

Q. Please describe Exhibit 6-11.

A. *Exhibit 6-11* computes the Distribution component of the cost of providing Street Light service. The right-most column, labelled "Distribution to Support SL, No SL O&M", is the revenue requirement allocated to Street Lighting excluding Street Lighting assets in account 373, related depreciation reserve and depreciation expense, Street Lighting maintenance in account 596, and allocated costs that follow; this is the distribution revenue requirement for customers that own and maintain their Street Lighting assets.

The column to the left, labelled "Additional for SL O&M", reflects Street Lighting maintenance in account 596 and allocated costs that follow; this is the distribution revenue requirement to O&M on Street Lighting. The column labelled "Total Distribution" is the total revenue requirement for customers that own their Street Lighting assets and maintenance is performed by the Company.

Q. Does this conclude your direct testimony today?

A. Yes.

SUMMARY

Mr. Gorman has more than 30 years of experience in the energy industry, including 20 years in rate and regulatory proceedings. He has testified as an expert witness on revenue requirements, class cost of service, revenue allocation and rate design, before the New York State Public Service Commission, and also before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New Hampshire Public Utilities Commission, Ontario Energy Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission.

Mr. Gorman also has experience in financial modeling, financial analysis and forecasting, developing accounting systems, competitive service, and treasury and financial management. He is a NYS Certified Public Accountant.

PROFESSIONAL EMPLOYMENT

2010 – Present *HSG Group, Inc.*

- President

1997 – 2010 *Black & Veatch Corporation (R.J. Rudden Associates before 2005)*

- Principal Consultant

1995 - 1997 *Independent Consultant*

1987 – 1995 *Trigen Energy Corporation*

- 1987-1993 Corporate Controller; Trigen was formed in 1987
- 1993-1995 Treasurer; Trigen had NYSE IPO listing in 1994

1982 - 1987 *Coleco Industries, Inc.*

- Director, Treasury

1976 - 1979 *Touche Ross & Co.*

- Staff Accountant

PROFESSIONAL EXPERIENCE

Utility Rate and Regulatory Accounting

Mr. Gorman has performed numerous class cost of service studies for electric and gas utilities, and has also prepared revenue requirements, developed revenue allocation proposals and rate designs. These assignments included development of test year data, establishment of cost causality, selection of allocation bases, development of allocators, and analysis of customer impacts and policy considerations.

Mr. Gorman also has extensive experience in financial accounting. As controller of Trigen Energy Corporation, he founded and built the finance and accounting function; developed reports, procedures and management tools; and managed subsidiary controllers across North America, including an IPO with NYSE listing.

Energy Project Analysis

Mr. Gorman has performed financial analyses of energy-related assets, including electric and gas distribution companies, power plants and transmission operators. These valuations included development of cash flows and financial statements based on both regulatory and accounting presentations, and included review of assumptions, analysis of data, modeling and forecasting, sensitivity testing and stress testing.

Among these analyses are: Valuations of power plants, combined heat and power plants and energy companies for the purpose of acquisition; Valuation and assessment of alternatives for the waste-to-energy assets and other energy assets of a diversified company on behalf of an interested acquirer; Valuation of the common stock of a publicly traded multi-jurisdiction utility for the purpose of investment; Assessment of strategic fit and valuation for a utility seeking to diversify into energy-related services; and Assistance with valuation and preparation for negotiation for a private entity seeking a buyer for energy assets.

Energy Project Financing

Mr. Gorman has negotiated and completed transactions including construction and term loans, tax-exempt bonds, taxable bonds, subordinated debt and asset-backed (receivables and inventory) revolving credit facilities. He has worked successfully with lenders and borrowers to source and structure transactions, and was instrumental in negotiating loan documents and in designing power sale and supply procurement contracts to be financed.

Mr. Gorman has supported energy projects in connection with due diligence for financing, including contract review, financial modeling, supply analysis, forward price projections, and economic valuation with cash flow forecasting, and the identification, assessment and mitigation of financial and operating risks for the project and its investors.

Financial Management and Related Areas

Mr. Gorman has developed, sourced and procured competitive contracts for loans as well as for energy, both as principal and on behalf of clients. He has bought and sold interest rate and currency forward contracts for the purpose of managing risk.

He managed the corporate insurance portfolios and the benefit plans for Trigen Energy Corporation and for Coleco Industries.

Computer Modeling and Decision Support

Mr. Gorman is an accomplished modeler with expertise in spreadsheet and database applications, as well as the use of programming tools. He has developed analytical tools to perform valuations, projections and simulations. These models have been applied to financial analysis, cost allocations, rate design and pricing, forecasting revenue requirements, numerous tax and accounting matters, supply modeling and optimizations. Several of these models have contained interactive modules for automated scenario testing and sensitivity analysis.

PUBLICATIONS AND PRESENTATIONS

"What Wall Street Needs From FERC," published in R. J. Rudden Financial, LLC's *Energy Capital Markets Report*, September 2002

"A Balanced Look at Balance Sheets," published in R.J. Rudden Financial, LLC's *Energy Capital Markets Report,* June 2002

"From Wires To Riches: Shareholder Value Creation In The T&D Business," April 2002 (co-authored).

"Assessment of Retail Choice Programs," presented at the American Gas Association Rate and Strategic Issues Committee Conference, March 2002

"Value Creation With Transmission Assets," quoted in *Electrical World's Special Edition Quarter 1, 2002*, March 2002

"The Remarkable Story on Enron," published in Scudder's *Annual End of Year Issue*, December 2001

EDUCATION

New York University, B.S., Accounting, 1976

Harvard Business School, MBA, 1981

Relevant Projects- Howard S. Gorman				
Jurisdiction	**Docket**	**Client**	**Date**	**Subject Matter**
Rhode Island	RIPUC 4770	Narragansett Electric	2017	Electric class cost of service; revenue allocation; rate design
Pennsylvania	R-2017-2593142	Veolia Energy Philadelphia	2017	Steam system revenue requirements and sales forecast
New York	17-E-0238	Niagara Mohawk (Electric)	2017	Electric class cost of service; revenue allocation; rate design; distribution marginal cost
New York	17-G-0239	Niagara Mohawk (Gas)	2017	Gas class cost of service; revenue allocation; rate design; distribution marginal cost
Pennsylvania	R-2016-2531550	Citizens' Electric of Lewisburg, PA	2016	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania	R-2016-2531551	Wellsboro Electric Company	2016	Electric revenue requirements, class cost of service, revenue allocation, rate design
New Hampshire	DE 16-383	Granite State Electric	2016	Electric revenue requirements
New York	16-G-0058 /0059	Brooklyn Union Gas / KeySpan Gas East	2016	Gas class cost of service; revenue allocation; rate design; distribution marginal cost
Massachusetts	DPU 15-155	Massachusetts Electric and Nantucket Electric	2015	Distribution marginal cost study
New York	15-E-0184	Jamestown Board of Public Utilities	2015	Electric revenue requirements
New Hampshire	DE14-180	Energy North Natural Gas	2014	Gas revenue requirements
New York	14-E-0035	Village of Freeport	2014	Electric revenue requirements; sales forecast; rate design

Relevant Projects- Howard S. Gorman				
Jurisdiction	**Docket**	**Client**	**Date**	**Subject Matter**
Pennsylvania	R-2013-2386293	Veolia Energy Philadelphia	2013	Steam system revenue requirements and sales forecast
Pennsylvania	R-2013-2372129	Duquesne Light	2013	Electric class cost of service; revenue allocation; rate design
New Hampshire	DE13-063	Granite State Electric	2013	Electric revenue requirements, class cost of service (marginal cost); revenue allocation; rate design
Ontario	EB-2005-0378 et al	Hydro One Networks Inc.	2013, 2012, 2010, 2009, 2008, 2006, 2005	Electric Transmission and Distribution Cost allocation; OH capitalization rates
Ontario	EB-2007-0905 et al	Ontario Power Generation	2013, 2010, 2006	Electric Cost allocation methodology
New York	12-E-0201	Niagara Mohawk (Electric)	2012	Electric class cost of service; revenue allocation
Rhode Island	RIPUC 4323	Narragansett Electric	2012	Electric class cost of service
New York	11-E-0590	Village of Rockville Centre	2011	Electric revenue requirements; rate design; sales forecast
New York	11-G-0142	Chautauqua Utilities, Inc.	2011	Gas revenue requirements, rate design
Pennsylvania	R-2010-2179103	Kellogg Company (intervenor)	2010	Water class cost of service; revenue allocation
Pennsylvania	R-2010-2179522	Duquesne Light	2010	Electric class cost of service; revenue allocation; rate design

Relevant Projects- Howard S. Gorman				
Jurisdiction	**Docket**	**Client**	**Date**	**Subject Matter**
Pennsylvania	R-2010-2172662	Wellsboro Electric	2010	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania	R-2010-2172665	Citizens' Electric of Lewisburg, PA	2010	Electric revenue requirements, class cost of service, revenue allocation, rate design
Pennsylvania	R-2010-2174470	Valley Energy, Inc.	2010	Gas revenue requirements, rate design
Pennsylvania	R-2010-2161592	PECO Energy (Gas)	2010	Gas class cost of service; revenue allocation; rate design
Pennsylvania	R-2010-2161575	PECO Energy (Electric)	2010	Electric class cost of service; revenue allocation; rate design
New York	10-E-0050	Niagara Mohawk (Electric)	2010	Electric class cost of service
New York	09-E-0862	Jamestown Board of Public Utilities	2009	Electric revenue requirements
Pennsylvania	R-2009 2139884	Philadelphia Gas Works	2009	Gas class cost of service; revenue allocation
Rhode Island	RIPUC 4065	Narragansett Electric	2009	Electric class cost of service; revenue allocation; rate design
Massachusetts	DPU 09-39	Massachusetts Electric and Nantucket Electric	2009	Electric revenue requirements; adjustment mechanisms; class cost of service; revenue allocation; rate design
Pennsylvania	R-2008-2028394	PECO Energy (Gas)	2008	Gas class cost of service; revenue allocation; rate design
Pennsylvania	R-00072350	Wellsboro Electric	2007	Electric revenue requirements; rate design
Pennsylvania	R-00072348	Citizens' Electric of Lewisburg, PA	2007	Electric revenue requirements; rate design

Relevant Projects- Howard S. Gorman				
Jurisdiction	**Docket**	**Client**	**Date**	**Subject Matter**
Pennsylvania	R-00072349	Valley Energy, Inc.	2007	Gas revenue requirements; rate design
Pennsylvania	R-00061931	Philadelphia Gas Works	2006	Gas class cost of service; revenue allocation; rate design
New York	06-E-0911	Village of Freeport	2006	Electric revenue requirements; rate design
Pennsylvania	R-00061346	Duquesne Light	2006	Electric class cost of service; revenue allocation; rate design
New York	03-E-1568	Village of Rockville Centre	2003	Electric revenue requirements; rate design; sales forecast
New Jersey	ER02080506 et al ER02050303 et al	Gerdau AmeriSteel aka Co-Steel (intervenor)	2002	Electric cost allocation and rate design; industrial rates
Pennsylvania	M-00021612	Philadelphia Gas Works	2002	Gas rate unbundling
Pennsylvania	R- 00017034	Philadelphia Gas Works	2002	Gas class cost of service
Pennsylvania	R- 00006042	Philadelphia Gas Works	2001	Gas class cost of service; recovery of fixed costs

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3000124

Duquesne Light Company

Statement No. 15

DIRECT TESTIMONY OF DAVID B. OGDEN

Dated: March 28, 2018

Q. Please state your full name and business address.

A. My name is David B. Ogden. My business address is Duquesne Light Company, 411 Seventh Avenue, Pittsburgh, PA 15219.

Q. What is your position at Duquesne Light Company?

A. I am employed by Duquesne Light Company ("Duquesne Light" or "Company") as the Manager, Rates and Tariff Services.

Q. How long have you worked at Duquesne Light?

A. I have been employed by Duquesne Light Company for over nine (9) years.

Q. What are your current responsibilities?

A. I am responsible for overseeing the Company's retail rates and wholesale transmission rates, which includes supervising the preparation, development and implementation of the distribution rates proposed in this proceeding.

Q. What are your qualifications, work experience and educational background?

A. I received a Bachelor of Science in Business Administration Degree with a major in Accounting from Clarion University of Pennsylvania in 2001. I am a Certified Public Accountant. I began my career at the Company in 2008 as the Supervisor of Derivative Accounting and Special Projects. Over the last eight years, I have held supervisory and managerial positions within Accounting, Financial Planning and Analysis and currently the Rates department.

Prior to joining Duquesne Light, I was a senior audit associate in the Pittsburgh office of PricewaterhouseCoopers LLP, a public accounting firm, where I performed attestation, advisory and compliance services for clients throughout the United States. Prior to joining

PricewaterhouseCoopers, I held audit positions within the Allegheny County Controllers Office.

Q. Have you previously testified before the Pennsylvania Utility Commission?

A. Yes. I have testified in the Company's Default Service Plan ("DSP VIII") proceeding at Docket No. P-2016-2543140 and have testified in the Company's Distribution System Improvement Charge ("DSIC") proceeding at Docket No. P-2016-2540046.

Q. Are you sponsoring any exhibits, parts of exhibits or responses to the Commission's filing requirements as part of your direct testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit DBO-1, which is the proposed tariff supplement to the currently effective Tariff Electric Pa. P.U.C. No. 24 implementing the proposed rates, riders and tariff revisions in this proceeding
- Exhibit DBO-2, which is a redline version of Exhibit DBO-1
- Exhibit DBO-3, which is the Digest of Proposed Changes contained within Duquesne Light's proposed supplement
- Exhibit DBO-4, which contains the calculations supporting the proposed new street light rates
- Exhibit DBO-5, which contains an updated unbundling schedule

I am sponsoring Schedule D-5D of Duquesne Light Exhibits 2, 3 and 4 and also sponsoring the Company's responses to the following filing requirements:

- IV-A 1-4: Summary of Individual Rate Effects
- IV-B: Description of Proposed Tariff Changes
- IV-C: Revenue Effects and Billing Analysis for Changed Rates

- IV-D 1 and 2: Monthly Billing Effects Charts and Data
- IV-E 2: Comparisons Showing Cost and Proposed Base Rate Revenues for Residential and Demand/Energy Rate Schedules

Q. Please explain how these filing requirements were prepared.

A. These filing requirements were prepared either by me or under my direct supervision. They were prepared, to the best of my knowledge, in accordance with Commission requirements and practice.

Q. What is the purpose of your direct testimony regarding Duquesne Light's request for increased rates?

A. The purpose of my testimony is to address the following:

1. The allocation of the proposed revenue increase among the rate classes.
2. The proposed rate design for distribution charges.
3. The revenue impact by rate schedule.
4. The proof of revenue at current and proposed rates.
5. Proposed tariff changes.

Q. How is your testimony organized?

A. First, I will explain the Company's goals and objectives in allocating the proposed revenue increase. I will show how the proposed revenue increase was allocated among the rate classes and the resulting relative rate class returns. These items are discussed in the "Allocation of Proposed Revenue Increase" section.

Second, I will describe the rate design principles and how they were used to determine the proposed rates. I will then discuss how the proposed rates, when applied to forecasted billing units, achieve the target allocated revenue for each rate class. These two items are discussed in the "Rate Design" section.

Third, I will address the proposed revenue impact by rate schedule and how the proof of revenue at current and proposed rates was developed to demonstrate that the proposed rates produce the target revenue for each class. These items are discussed in two sections, "Revenue Impact by Rate Schedule" and "Proof of Revenue," respectively.

Finally, I will discuss the proposed changes to the Company's retail tariff to implement these new rates, as well as describe any proposed changes to the Rules and Regulations section and Riders of the tariff.

Q. Were all of the proposed rate design changes and tariff changes also prepared under your direction or supervision?

A. Yes. All of the rate design work was prepared by me or under my direct supervision as well as all tariff changes as presented in Exhibit DBO-3, with the exception of the changes to Rider No. 5 – Universal Service Charge ("USC") which is sponsored by Ms. Scholl at DLC Statement No. 7, and Rider No. 21 – Net Metering Service which is sponsored by Mr. Karcher at DLC Statement No. 5.

I. ALLOCATION OF PROPOSED REVENUE INCREASE

Q. What were the Company's goals and objectives in allocating the revenue increase?

A. The Company proposes to continue the objectives it established in its 2006, 2010 and 2013 distribution rate case proceedings. The first objective was to move each rate class closer to the full cost to provide service to each rate class, as determined in the class cost allocation study ("ACOS") prepared by Mr. Gorman in Exhibit 6 at DLC Statement No. 14. Whether the proposed revenue allocation reflects the full cost of service can be evaluated by whether the rates for the customer class fully recover the distribution costs allocated to that class, as measured by the unitized returns at proposed rates. A unitized rate of return greater than 1.0 means that the rate class is contributing a greater than average rate of return. A unitized rate of return less than one means that the rate class is providing a less than average rate of return. The Company's goal in this rate case, as in its 2006, 2010 and 2013 rate cases, is for the proposed rates to move each rate class closer to a unitized rate of return of 1.0, than the current rates.

The second overall objective is to mitigate the rate impact both on rate classes and on individual customer subgroups while continuing to progress to the rate class fully allocated cost of service and reducing the subsidization among classes. In this proceeding, the Company's goal was to limit the distribution revenue increase to any one rate class to no more than 1.50 times the overall system average increase on a distribution bill basis. This limitation balances the shift to cost of service with concerns regarding customer bill impact.

Q. Have the revenue impacts to each rate class been calculated using the fully allocated class cost of service results?

A. Yes. As described by Mr. Gorman at DLC Statement No. 14, fundamental cost allocation principles were used to functionalize, classify and allocate the revenue requirement among the rate classes in order to determine the fully allocated cost of service, which set the base parameters for revenue allocation and rate design. The rate class revenue requirements that reflect cost causation and serve as the starting point for revenue allocation and rate design are shown in Exhibit 6-2 and 6-3. Exhibit 6-2, line 27 shows the revenue increases or decreases that would be required if rates were set to recover each class' fully allocated cost of service (at the Company's proposed distribution rate of return of 8.06%).

Q. Please explain how the revenue increase has been allocated across rate classes.

A. The Company has established a tolerance band, representing returns from 75 to 125 percent of the overall system return of 5.27% at current rates, equal to returns of 3.95 to 6.58 percent. The use of the tolerance band allows the Company to rely on the class cost allocation study results as a guide to allocate the increased revenue requirement fairly, while also promoting the goal of gradualism. The use of the tolerance band is also intended to avoid conflicts resulting from minor disagreements about the allocations of costs in the ACOS.

An overall average distribution increase of $81.6 million, or 16.13%, is required to produce the proposed return of 8.06%. In Step 1 of the revenue allocation (Exhibit 6-10, line 16), classes within the tolerance band (i.e. GS, GM<25, GMH>25, GLH, L) received an initial increase of 16.93% (1.05 times the overall average increase). Classes producing returns at present rates above the tolerance band (i.e. GM>25, GL, HVPS, SE, SL, UMS) received an initial average increase of 11.29% (0.70 times the overall average increase), and classes below the tolerance band (i.e. RS, RH, RA, GMH<25) received an initial average increase of 20.96% (1.30 times the overall average increase). The use of the tolerance band results in a revenue overage of $7.3 million, compared to the required increase of $81.6 million (line 8).

In Step 2 of the revenue allocation, the Company applied a 10% revenue reduction for Rate UMS, a substantial revenue reduction for Rate HVPS, and a zero increase for Rate SE and SL, in order to produce returns that move these classes closer to full cost of service. This reduced total revenue by $2.0 million (line 18).

In Step 3 of the revenue allocation, the $5.3 million net result of the $7.3 million overage in Step 1 and the $2.0 million shortfall in Step 2 was allocated in proportion to revenue at current rates (line 19).

Q. Is there an exhibit that presents the Company's proposed revenue allocation?

A. Yes, Exhibit 6-10 presents the proposed distribution revenue increase by rate class.

The results of the ACOS, including returns at present rates and placement within the tolerance band, are on lines 1-12. The revenue allocation, including the tolerance band increases, the judgmental changes and the re-allocation of the net overage, is presented on lines 16-19. The class returns at proposed revenue are computed on lines 21-30. The relative returns at proposed revenue and progress toward unity are on lines 32-36.

Class revenue at proposed rates is shown on line 23. These revenue amounts include Other Revenue, which will be recognized when computing the rates needed to produce the class revenue targets.

Q. Was the Company able to achieve its desired goals?

A. Under these rates as proposed, yes. Exhibit 6-10, lines 32-36, illustrate that each class is moving closer to the system average rate of return. In addition, no class received an increase greater than 1.24 times the system average, which is much lower than the constraint of 1.5 times which I described earlier.

Q. Was a schedule prepared showing the proposed targeted revenues for each rate class resulting from this revenue allocation?

A. Yes. The proposed targeted revenues for each rate class that result from application of the above principles are shown in DFR IV-A, Pages 1-3 and Schedule D-5D, Exhibit 2.

II. RATE DESIGN

Q. Please describe the goals and objectives used in designing the proposed distribution rates.

A. The primary goal was to design rates that, when applied to forecasted billing determinants, produce the proposed revenue increase and the proposed targeted revenues for each rate class for the fully projected future test year. In addition, the Company continued its plan described in recent rate cases to migrate toward rates that reflect the services provided by a delivery company, and that also reflect the way in which fixed costs are incurred. To achieve these goals, the Company proposes to maintain its goal of designing rates that emphasize fixed monthly charges and demand based charges, where appropriate, to recover costs. At the same time, the Company recognizes the potential impact on individual customers by eliminating familiar rate structures, and the overall goal to keep rates transparent and easy for the customer to understand. The Company developed rates for each rate class that balance these objectives.

Q. Please describe the proposed rate design for customers on Rate RS.

A. The Company proposes to continue to use a combination of fixed and energy-based rates for all of the residential rate classes, i.e. Residential Service Rate RS, Residential Heating Service Rate RH and Residential Service Add-On Heat Pump Rate RA. The Company proposes to increase the fixed monthly charge to $16.25 per month, which is supported by the fixed cost analysis of serving a residential customer identified in Exhibit 6-4A. As described in more detail below, the Company is proposing to roll its Smart Meter Charge ("SMC") into base rates as part of this rate case consistent with the cost allocation agreed upon in the Company's "Petition of Duquesne Light Company for Approval of Smart

Meter Technology Procurement and Installation Plan" at Docket No. M-2009-2123948. The SMC is currently a fixed charge per month, and is taken into consideration in the abovementioned fixed cost analysis. I also note that a higher fixed charge provides some revenue stability for the Company and cost stability for customers, and encourages the Company to support conservation measures by reducing the benefit to the Company from higher sales volumes.

Recovery of the remaining revenue (that is, target revenue less the amount recovered through the fixed monthly charge) will be through an increased flat usage charge per kWh.

Q. Please describe the rate design for customers on Rate RH and RA.

A. Rate RH and Rate RA are the Company's residential space heating rates. The current rate structures use a combination of fixed and energy-based variable charges similar to rate RS, except that Rates RH and RA have a lower usage charge during the November to April heating season. Currently, Rates RH and RA have the same rate structure as Rate RS during the May through October non-heating season.

For Rates RH and RA, the Company proposes the same fixed monthly charge as rate RS and the same usage charge as Rate RS during the non-heating months since there is not a material difference in average customer load or usage of these rate classes during those months.

The Company recognizes space heating customers use considerably more electricity during the heating season than customers on basic residential service Rate RS, although the costs of providing service are fixed. The Company proposes to retain the lower kWh charge during the heating season, which reflects the fixed costs spread over a larger number of kWh.

Q. Please describe how the rate design objectives were implemented for commercial and industrial customers on General Service Small and Medium Rate GS/GM.

A. This rate represents a diverse group of over 51,200 commercial and industrial ("C&I") customers. This group consists of approximately 22,900 non-demand-billed customers on Rate GS, approximately 18,400 customers on Rate GM with monthly demand less than 25 kW and approximately 9,900 customers on Rate GM with monthly demand equal to or greater than 25 kW. The categorization of customers at less than 25 kW and equal to or greater than 25 kW was established and approved in the Company's 2007 default service filing and continued and approved for the distribution business in the Company's 2010 and 2013 base rate proceedings. The Company proposes to continue this separation point in this proceeding.

Q. What is the distribution rate design that is being proposed in this proceeding for rate GS non-demand customers?

A. For Rate GS, the Company is proposing the same rate design as implemented in the previous base rate proceeding. The Company is proposing to bill non-demand commercial customers the same fixed monthly charge as residential customers, and a flat usage charge similar to how these customers are billed at present rates, to recover the balance of the target revenues.

Q. What is the distribution rate design that is being proposed in this proceeding for customers on Rate GM under 25 kW and Rate GM equal to or over 25 kW?

A. The Company is proposing to maintain the same distribution rate structures that exist today. The Company first used the customer-charge costs identified in Exhibits 6-4C and 6-4D and the demand-related costs identified in Exhibit 6-3, to establish the fixed monthly charges. The charges include the first 5 kW of demand.

For each class, the balance of the revenue target is recovered through a combination of demand and kWh charges. For Rate GM under 25 kW, the kWh charge is increased by approximately the same percentage as the fixed charge (when including the surcharges being rolled into each component) which will mitigate intra-class shifts. For Rate GM above 25 kW demand, the demand charge is the same as GM under 25 kW ($7.09 per kW-month of billed demand) and the kWh charge is the rate needed to produce the revenue target.

Q. What is the distribution rate design that is being proposed for customers on Rate GMH under 25 kW and Rate GMH equal to or over 25 kW?

A. GMH under 25 kW and GMH over 25 kW are the complementary electric space heating rates of rate schedules GM under 25 kW and GM over 25 kW, and apply to approximately 3,300 commercial and industrial customers. The Company is proposing to maintain the same distribution rate structures that exist today. The fixed monthly charges include 5kW of demand and are based on the customer-charge costs identified in Exhibit 6-4E and the demand-related costs identified in Exhibit 6-3. The proposed $56.00 fixed monthly charge is the same as proposed for GM under 25 kW.

For the heating months (October to May), customers will not be billed for demand, only for usage, the same as today's rate structure. The summer rates per kW and per kWh rates are the same as for rate class GM under 25 kW. The winter kWh charge is designed to recover the balance of the target revenue.

Q. Please describe the current distribution rate design for large commercial and industrial customers on Rate GL.

A. Rate GL is applicable to approximately 730 customers. Currently, the rate schedule contains a fixed charge for the first 300 kW of demand and a demand charge for each additional kW of demand. There are no distribution kWh charges associated with this rate schedule.

Q. What is the distribution rate design that is being proposed for Rate GL?

A. The Company is proposing to continue the same rate structure for Rate GL. The fixed charge, which includes the first block of demand (300 kW), was increased by approximately the rate class revenue increase. The balance of the target revenues are recovered through the charge for demand over 300 kW.

Q. What is the rate design that is being proposed in this proceeding for Rate GLH?

A. Rate GLH is the complementary electric space heating rate to Rate GL and applies to approximately 90 customers. The Company proposes to continue the existing rate structure and proposes rate design principles similar in concept to those used Rate GMH in this proceeding. For the non-heating season months (June to September), these customers will be billed the same charges as Rate GL. For the heating months (October to May), the Company is proposing to bill a flat usage charge per kilowatt-hour.

Q. Please describe the current distribution rate design for large commercial and industrial customers on Rate L.

A. Rate L is currently applicable to 26 customers. These customers represent some of the largest customers served by the Company and are diverse in size (demand) as well as service voltage. Currently, the Company offers the following:

- Rate L Service Voltage Less than 138 kV is applicable to approximately 22 customers. Currently, the rate schedule contains a minimum charge for the first 5,000 kW of demand and a demand charge for each additional kW of demand. There are no distribution usage charges associated with these rate schedules.
- Rate L Service Voltage 138 kV and Greater is applicable to approximately four (4) customers. The rate schedule represents a voltage-based rate that contains a monthly fixed distribution charge. There are no variable demand distribution charges or variable usage distribution charges.

Q. What is the distribution rate design that is being proposed for Rate L?

A. The Company is proposing the following:

- Rate L Service Voltage Less than 138 kV will continue the existing rate structure using a fixed monthly charge that includes the first 5,000 kW of demand, and an additional per kW charge for monthly demand in excess of 5,000 kW. The charge for monthly demand in excess of 5,000 kW was not changed substantially from the present level (when reflecting the rolled-in surcharges), and the fixed monthly charge was set to produce the balance of the revenue target for the class. This moved the fixed charge much closer to the costs incurred by the Company for the first 5,000 kW as reflected on Exhibits 6-4F and 6-3.
- Rate L Service Voltage 138 kV and Greater will be migrated to Rate HVPS as a combined transmission voltage based rate. Currently, these customers are not eligible for Rate HVPS because their monthly billing demand is less than the 30,000 kW minimum billing demand requirement of Rate HVPS. As further

described below, the Company is proposing to reduce the Rate HVPS 30,000 kW threshold requirement to 5,000 kW.

Q. Please describe the current distribution rate design for Rate HVPS.

A. There are currently three (3) customers on Rate HVPS each with a monthly demand greater than 30,000 kW in accordance with the tariff. The rate schedule contains a monthly three-tiered fixed distribution charge and there are no variable demand distribution charges or variable usage distribution charges.

Q. What is the distribution rate design that is being proposed for Rate HVPS?

A. For Rate HVPS, the Company is proposing to reduce the 30,000 kW threshold to 5,000 kW in order to combine the Company's two transmission voltage based rates. This includes the four (4) Rate L Service Voltage 138 kV and Greater with the three (3) Rate HVPS customers supplied at 69 kV or higher. The Company further proposes to keep the same rate structure currently in place using a monthly fixed charge which was approved in the Company's last distribution rate case proceeding. Each of the fixed monthly charges have been reduced by the same percentage, as needed to produce the class revenue target.

Q. What is the Company's basis for combining Rate L Service Voltage 138 kV and Greater with Rate HVPS?

A. The combined customer class is made up of customers that are served at transmission level voltages (i.e. 69kV or above), and are all industrial classification with similar load profiles; they use minimal distribution assets (i.e. meters). Therefore, Mr. Gorman at DLC Statement No. 14 combined Rate L Service Voltage 138 kV and Greater with Rate HVPS (service supplied at 69 kV or higher) as part of the Company's class cost allocation study. By combining the transmission level voltages together (i.e. 69 kV or above), the Company has determined that one Rate L Service Voltage less than 138 kV, currently being served at 69 kV, will become eligible for Rate HVPS with a minimum contract demand of 5,000 kW. These eight (8) combined customers are reflected in the proof of revenue (DLC Exhibit 1, Part IV-C) and the rate design for Rate HVPS. The three tiers of the rate structure were all decreased by an equal percentage to produce the target revenue.

Q. What changes are being proposed to the distribution rates of the lighting and unmetered rate classes?

A. The Company has aggregated Rates AL, SM, SH and PAL for cost of service and revenue allocation purposes. Rate SE and Rate UMS (Unmetered Service) are treated individually. The Company is proposing to retain the same rate structure for these rate classes.

For Rates AL, SM, SH and PAL, the Company is proposing an across-the-board percentage change to each rate. These changes, when combined with the elimination of surcharges that are being rolled into rates (DSIC and SMC) will produce the revenue targets, which is essentially no change for these classes.

For Rate SE, the Company is proposing a rate which, when combined with the elimination of surcharges that are being rolled into rates (DSIC and SMC) will produce the revenue target, which is essentially no increase or decrease for this class.

For Rate UMS, the Company is proposing to keep the current $10.00 per month fixed charge, plus a per kWh rate. When combined with the elimination of surcharges that are being rolled into rates (DSIC and SMC) the proposed rates will produce the revenue target, which is a 10 percent decrease for this class.

Q. Is the Company proposing any changes to its transmission rates in this proceeding?

A. No, the Company is not proposing to change transmission rates in this proceeding. The Company has adopted the FERC formula rate making process to establish an annual revenue requirement and the associated wholesale network integrated transmission service rate that changes June 1 every year. The current wholesale rate is not affected by this proceeding.

Q. Is the Transmission Service Charge ("TSC") changing because of this filing?

A. No. The Company submitted and the Commission approved the TSC in the Company's 2006 distribution rate case. The purpose of the TSC is to enable the Company to recover, on a dollar-for-dollar basis, the expenses it incurs from PJM as a provider of transmission service to retail customers who receive default service from the Company. Electric generation suppliers are responsible for transmission charges for shopping customers. The Company's retail transmission rates were redesigned to reflect the FERC formula and the method of providing and paying for transmission service through PJM. The TSC is updated June 1 every year in conjunction with the update to the FERC formula. The TSC has worked successfully since it was implemented, and the Company is not proposing changes to the TSC or changes to the TSC retail rates in this proceeding.

III. REVENUE IMPACT BY RATE SCHEDULE

Q. Have the annual revenue effects of the new proposed rates been calculated?

A. Yes. Schedule D-5D of Duquesne Light Exhibit No. 2 was prepared in accordance with PA PUC Data Filing Requirement IV-A. The pages in this schedule provide the rate class revenue impact and the overall revenue effect for the fully projected future test year period.

Q. Please explain Schedule D-5D for the fully projected future test year.

A. Schedule D-5D Page 1 identifies the forecasted customers, sales and retail revenue by rate class for distribution, transmission and generation. The customers, sales and revenues are based on the billing determinants provided in Mr. Mobley's forecast at DLC Statement No. 3. Also shown are the forecasted revenues the Company plans to collect at current rates through tariff riders for Rider No. 1 - Retail Market Enhancement Surcharge ("RMES"), Rider No. 5 -Universal Service Charge ("USC"), Rider No. 15A - Phase III Energy Efficiency and Conservation Surcharge ("EEC III"), Rider No. 20 - SMC, Rider No. 22 - DSIC and Rider No. 10 - State Tax Adjustment ("STAS"). The Customer Assistance Program ("CAP") revenue credit is the billing deficiency associated with CAP customers that is recovered through the USC charge.

Page 2 reflects the forecasted revenue at current rates with certain surcharge revenue removed and only the Purchase of Receivable ("POR") portion of the RMES, SMC, DSIC and STAS, revenue shown. As further described below, the Company is proposing to roll the POR portion of the RMES, SMC and the DSIC into base rates. The STAS is proposed to be set at 0% with the associated taxes recovered in the proposed distribution charges. Schedule D-5D, Line 28, Page 2 reflects the reduction in revenue that the Company expects to experience related to the decrease in retail sales load that the Company is forecasting. Mr. O'Brien at DLC Statement No. 9 describes the retail sales load revenue reduction that is calculated in Exhibit No. 2, Schedule D-5B, and Mr. Mobley's Exhibit TM-2 identifies the Company's forecasted retail sales forecast that was utilized in calculating the reduction in revenue. The distribution revenue in Schedule D-5D, Column I, Page 2 is the base distribution revenue from which the requested increase is measured. The total revenue on

Page 2 ties to the total revenue described by Mr. O'Brien with his revenue adjustments in Exhibit No. 2, Schedule D-1, Page 1.

Page 3 of Schedule D-5D shows the distribution revenue and total revenue at the requested revenue increase and the respective increases on a percentage basis.

For illustrative purposes, Pages 4-6 provide similar calculations assuming 100% default service supply load.

IV. PROOF OF REVENUE

Q. Was a bill frequency analysis or proof of revenue calculation prepared?

A. Yes. Attachment DFR IV-C-Proof was prepared in accordance with the Commission's Data Filing Requirement IV-C and provides the calculation of revenues at current and proposed rates. Attachment DFR IV-C-Proof provides a calculation for each retail tariff rate schedule. For each rate schedule, the first column identifies the type of charge by business segment, i.e. customer charge, demand charge or energy charge for distribution, transmission and generation and for each rider, if applicable to that rate schedule. The second column provides the annual billing determinants for each charge forecasted by Mr. Mobley. The third column identifies the current and proposed rates for each block. The fourth column identifies the revenues derived by multiplying the billing determinants in the second column by the rates in the third column. The revenues computed on these pages produce the revenues shown on the respective pages of Schedule D-5D (Fully Projected Future Test Year).

Q. Do the forecasted revenues at current and proposed rates reflect reduced sales from the effects of energy efficiencies?

A. Yes. In developing the Company's sales forecast, Mr. Mobley at DLC Statement No. 3 accounts for the reduced sales due to energy efficiencies projected through the end of the fully projected future test year. The proposed rates and fully projected future test year revenue were calculated based on Mr. Mobley's sales forecast.

V. PROPOSED RETAIL TARIFF CHANGES

Q. Please describe the contents of Exhibit DBO-3.

A. This exhibit sets forth in detail the modifications being proposed to the Company's tariff provided in Exhibit DBO-1, including the changes in rates and rate design previously described in my testimony, to recover the proposed distribution revenue requirement that is being requested. The proposed modifications are also shown in a redline version of the tariff supplement provided in Exhibit DBO-2.

Q. Are you proposing changes to the Rules and Regulation section of the proposed tariff supplement?

A. Yes. The Company is proposing certain administerial changes as well as changes to reflect current business practices that are described in the list of modifications within DBO-2, as well as in Exhibit DBO-3, the Digest of Proposed Changes contained within Duquesne Light's proposed supplement.

Q. Are you proposing changes to the tariff rate schedules section of the proposed tariff supplement?

A. Yes. The distribution rates identified in each rate schedule in Exhibit DBO-1 have been modified to achieve the allocated revenue increase previously described in my testimony.

Aside from the proposed change to Rate L and Rate HVPS that I previously described, the Company is not proposing changes to the distribution rate structure in this proceeding. In addition, the Company is proposing new light emitting diode ("LED") street lighting rate options to Rate SM and adding the LED street light option to Rate SH and Rate PAL as part of the Company's expanded LED street light program which is sponsored by Mr. DeMatteo at DLC Statement. No. 6.

Q. **Please describe the proposed revisions to the LED street light rate options to the tariff.**

A. Rate SM, Street Lighting Municipal, Rate SH, Street Lighting Highway and Rate PAL, Private Area Lighting, offer street lighting options to municipal, highway, and non-municipal customers, respectively. The street light options include mercury vapor, high pressure sodium ("HPS") fixtures and Rate SM includes two LED fixtures. The Company proposes to remove the current LED fixture options in Rate SM and add new LED fixture options to these three (3) rate schedules.

Q. **Please describe the proposed revisions to the tariff to implement the LED street light rates?**

A. Several changes are needed to the tariff to implement the LED options. Rate SM, Rate SH and Rate PAL have been revised to include, in tabular format, the new LED fixture options and applicable distribution rates. These rates are a fixed charge per fixture per month similar to the mercury vapor fixtures and HPS fixture options. These rates are based on the calculations in Exhibit DBO-4 for each lamp size.

In addition, Rider No. 8, Default Service Supply ("DSS"), has been revised to show the new LED fixture options. The default service rates are monthly fixed charges based on the monthly kWh for each lamp size.

Finally, Appendix A, TSC has also been modified to add the LED fixture options.

Q. What DSS and TSC rate will the new LED street lighting customers initially pay?

A. The Company proposes to charge each LED street lighting option the HPS equivalent DSS and TSC rate until such time as new rates are updated. DSS street lighting rates are updated biannually effective June 1st and December 1st, and TSC rates are updated annually effective June 1st.

Q. What is the forecasted impact on revenues due to the expansion of LED street lighting?

A. A revenue analysis cannot be completed at this time. The level of customer participation is uncertain, and it would be speculative to quantify any impact on revenues at this point in time.

Q. How did the Company calculate the fixed charges for LED street lighting?

A. Exhibit DBO-4 contains the supporting calculations and data used to determine the monthly fixture cost for each lighting option offered. Page 1 contains the cost of service for each new offering. Pages 2 through 11 evidence the rate calculations for the new LED fixture offerings.

Q. How were the fixed kWh usages in the proposed tariff schedules determined for this unmetered service?

A. The lighting units will operate from dusk to dawn, which results in approximately 4,200 hours of operation per year. The respective lamp wattage is multiplied by the 4,200 hours of operation per year, divided by twelve months, and then divided by 1,000 to be converted into kilowatt-hour. This calculation establishes the fixed monthly kWh usage for each fixture.

Q. Are there any additional changes to the streetlight rate classes?

A. Yes. The Company is proposing to add a Customer Owned and Maintained street lighting option. By adding a Customer Owned and Maintained street lighting option, the Company would only charge for the distribution facilities that support the street light as determined in Exhibit 6-11 in the class cost allocation study prepared by Mr. Gorman at DLC Statement No. 14.

Q. Are there any changes or additions to riders in the tariff?

A. Yes, in addition to the above-mentioned changes to riders that are sponsored by Ms. Scholl at DLC Statement No. 7 and Mr. Karcher at DLC Statement No. 5, there are nine (9) riders and one (1) appendix that the Company is proposing to revise. First, the Company is proposing to update Rider No. 1, RMES to remove the provision to recover the POR program discount expense associated with the uncollectible expense of Electric Generation Supplier ("EGS") consolidated billings. Second, the Company is proposing to eliminate Rider No. 4 – Budget Billing HUD Financed Multi-Family Housing. Third, the Company is proposing to eliminate Rider No. 7 – Seams Elimination Charge Adjustment ("SECA"). Fourth, the Company is proposing to update the tables in the lighting sections of Rider No. 8 – DSS to accommodate the new LED street light fixtures in Rate Schedules SM, SH and PAL. Fifth, the Company is proposing to update the unbundling costs that are currently recovered in default service rates within Rider No. 8– Default Service Supply and Rider No. 9 - Day-Ahead Hourly Price Service. Sixth, the Company is proposing to reset Rider No. 10 - STAS to zero to reflect recovery of these charges in base rates. Seventh, the Company is proposing to update Rider No. 16, Service to Non-Utility Generating Facilities, to better define the charges for back-up power and to update the back-up power distribution charge based on the results of the Company's allocated cost of service study. Finally, the Company is proposing to reset both Rider No. 20 – SMC and Rider No. 22 –DSIC to zero to reflect recovery of these charges in base rates. The Company is not proposing any additional riders to the tariff.

Q. Please explain the change to Rider No. 1 – RMES.

A. Pursuant to Settlement Paragraph No. 22 in the Company's POLR VIII proceeding at Docket No. P-2016-2543140, the POR uncollectible expense was moved to the RMES for recovery until the next base rate proceeding. Consistent with the Settlement Agreement, the Company is proposing to revise Rider No. 1 so as to remove the recovery of the uncollectible expense from the rider and proposes to recoup the expense through the Company's uncollectible accounts claim within base rates (refer to Schedule D-10 within Exhibits 2 – Fully Projected Future Test Year Summary of Measures of Value & Rate of Return).

Q. Please explain the change to Rider No. 4 – Budget Billing HUD Financed Multi-Family Housing.

A. Rider No. 4 is an obsolete Rider that has not had any active customers for the past several years.

Q. Please explain the change to Rider No. 7 – SECA.

A. Effective August 16, 2005, Rider No. 7 - SECA Charge was introduced into the Company's tariff via Supplement No. 28 to Tariff No. 23. Rider No. 7 was instituted to recover actual SECA transmission charges billed to the Company by the PJM Interconnection, Inc. The SECA Charge was to remain in effect until the level of SECA charges paid by the Company were fully recovered, at which time the SECA charge billed under Rider No. 7 would terminate, subject to any final reconciliation required due to final resolutions of litigation. Effective June 1, 2007, Rider No. 7 was updated via Supplement No. 9 to Tariff No. 24 to reflect termination of billing of the SECA Charge and retention of Rider No. 7 until such time as the SECA charges were resolved at the FERC and all such charges were fully recovered and/or refunded by the Company. The FERC approved in totality PJM's settlement of the SECA refund on December 21, 2016, per Docket No. EL02-111-139. Effective June 1, 2017, via Supplement No. 157 to Tariff No. 24, the Company began to refund its portion of the SECA settlement through Appendix A –TSC. Since the TSC is subject to review and audit by the Commission, and the Commission shall review the level of charges produced by the TSC and the costs included therein, the Company is proposing to eliminate Rider No. 7 – SECA Charge since the matter has been resolved at the FERC and the rider is no longer applicable.

Q. Please explain the change to Rider No. 8 – DSS.

A. Rider No. 8 provides residential, commercial, industrial and lighting customers on the applicable rate schedules with a default service supply rate that is determined based on a request for proposal to acquire the energy to serve the load of customers taking service under the provisions of the rider. The Company is proposing to update the tables in the lighting section of the rider in order to accommodate the new LED street lighting fixtures offered.

The Company further proposes to update the unbundled costs that are currently recovered in default service rates for residential, small and medium procurement groups that was approved by the Commission as part of the Petition of Duquesne Light Company for Approval of a Default Service Plan for the Period June 1, 2017 to May 31, 2021 at

Docket P-2016-2543140. Exhibit DBO-5 reflects the updated unbundling costs. These updated unbundled costs will be fixed and reconciled only for differences between projected and actual consumption. The Company would reflect the updated unbundled costs in rates effective June 1, 2019, the first effective default service supply rate change for all classes after new distribution rates become effective January 1, 2019.

Q. Please explain the change to Rider No. 9 – Day-Ahead Hourly Price Service

A. Rider No. 9 provides large commercial and industrial customers with the ability to purchase their electric supply requirements on a day-ahead hourly basis. Similar to Rider No. 8 above, the Company is proposing to update the unbundling costs that are recovered through a fixed retail administrative ("FRA") rate in Rider No. 9 for the large procurement group. Exhibit DBO-5 reflects the updated unbundling costs. These updated unbundling expenses will be fixed and reconciled only for differences between projected and actual consumption. The Company would reflect the updated unbundled costs in rates effective June 1, 2019, the first effective FRA rate change after new distribution rates become effective January 1, 2019.

Q. Please explain the change to Rider No. 10 – STAS.

A. Rider No. 10 is a two-part surcharge to recover changes in taxes of the Commonwealth. Part 1 of the STAS reflects changes in tax rates for the Capital Stock Tax, Corporate Net Income Tax and Public Realty Tax, and is applicable only to the distribution charges of customer bills. Part 2 of the STAS reflects changes in the Gross Receipts Tax and is applicable to the distribution, transmission and generation charges for customers taking service from the Company. For presentation purposes in this filing, both parts of the

STAS have been set at 0%. The Company will submit its annual STAS reconciliation filing in December 2018, for any state tax changes not reflected in the base rate filing.

Q. Please provide a brief summary of Rider No. 16 – Service to Non-Utility Generating Facilities.

A. Rider No. 16 defines the Company's tariff requirements for back-up distribution service that applies to customer-owned, non-utility generating facilities. Customers pay tariff rates for supplementary power which is the distribution service supplied by the Company in addition to the electric energy that the non-utility generating facility generates itself. Customers pay Rider No. 16 charges for back-up distribution service to replace electric energy ordinarily provided by the non-utility generating facility (i.e. during an outage of the non-utility generating facility). The rider is applicable to all general service rate schedules with the exception of Rate GS/GM non-demand customers. There is currently one customer on Rider No. 16.

Q. What changes are being proposed to Rider No. 16 - Service to Non-Utility Generating Facilities?

A. The Company is proposing two changes to Rider No. 16:

(1) Tariff revisions with the intent to clarify the service being provided and the definition of billing determinates.

(2) The Company's proposed rate for Back-Up Service includes only direct costs to provide distribution service, as presented by Mr. Gorman at DLC Statement No. 14 on Exhibit 6-4H. The average cost for the applicable rates classes is $8.02 per kW, and a rate of $8.00 is the rate proposed for Rider 16 that more closely aligns the cost the Company incurs to provide Back-Up Service to customers.

Q. Please explain the proposed changes to Rider No. 20 – SMC.

A. In accordance with Act 129 of 2008 ("Act 129"), Electric Distribution Companies ("EDCs") are entitled to full and current recovery of costs associated with implementing a smart meter system. Act 129 allows an EDC to recover its net costs either: (1) on a current basis through a Section 1307e reconcilable surcharge; or (2) in base rates, with authority to defer costs incurred between base rate cases. EDCs were given the option to choose either method. In its Petition for Approval of a Smart Meter Technology Procurement and Installation Plan at Docket No. M-2009-2123948, Duquesne Light received approval to recover its smart meter costs through a Section 1307e surcharge, namely, its Rider No. 20 – SMC. In addition, Duquesne Light explained in its Petition that, when its smart meter system is fully deployed, it would be appropriate to roll the smart meter program costs into its base rates. The SMC has been in place since August 1, 2010, and, the smart meter deployment is projected to be fully deployed by the end of the FPFTY. For these reasons, Duquesne Light is proposing to roll smart meter costs into its base rate revenue requirement in this case. In this distribution base rate filing, the Company has included the costs of its SMC as projected by the end of the FPFTY in base rates.

Q. Will the SMC be eliminated as a result of the roll-in?

A. Yes, but not as part of this case. Although the on-going smart meter costs are being rolled into base rates upon the effective date of those rates, any over/under collection balance that may exist at that time will be refunded or recouped, as applicable, through the SMC. Consequently, the SMC must remain in place as the vehicle for that true-up. Once the over/under balance has been recouped or refunded, as applicable, Duquesne Light will propose to eliminate the SMC in a future filing.

The Company is proposing to roll-in the SMC in two steps. The first step includes rolling the projected SMC surcharge revenue into present distribution rates as evidenced in Exhibit 2, Schedule D-5D, Column F, Page 2. As described earlier, the distribution revenues in Schedule D-5D, Column I, Page 2 are the base distribution revenues from which the requested increase is measured. The total revenue on Page 2 ties to the total revenue described by Mr. O'Brien with his revenue adjustments on Exhibit No. 2, Schedule D-1, Page 1. The second step includes rolling the projected SMC assets into the base distribution rate base, which is as evidenced in each of Mr. O'Brien's Exhibits (2 through 4), Schedule C-2, Page 3, lines 48-50. Mr. O'Brien explains these adjustments in more detail within DLC Statement No. 9.

Q. Please briefly describe the Company's DSIC.

A. The purpose of the DSIC is to recover the reasonable and prudent capital costs incurred to repair, improve, or replace eligible property which is completed and placed in service between base rate cases. The DSIC provides public utilities, such as Duquesne Light, with the resources to accelerate the replacement of aging infrastructure.

Q. Please explain the proposed changes to Rider No. 22 – DSIC.

A. In this distribution base rate filing, the Company has included the costs recovered under its existing DSIC in base rates, as required by Section 1358(b) of the Public Utility Code. The Company is proposing to include the capital investment and associated depreciation and tax effects for the DSIC in base rates. With the exception of prior period over/under collections ("E-Factor"), the Company will reset Rider No. 22 to zero as of the effective date of the base rates determined in this case. Rider No. 22 will remain at zero, with the exception of E-Factor, until Duquesne Light has added plant within DSIC eligible accounts in excess of the total claimed amount included in its estimated December 31, 2019, rate base in the present case.

Similar to the roll-in of the SMC as described above, the Company is proposing to roll-in the DSIC in two steps. The first step includes rolling the projected DSIC surcharge revenue into present distribution rates as evidenced in Exhibit 2, Schedule D-5D, Column H, Page 2. As described earlier, the distribution revenues in Schedule D-5D, Column I, Page 2 are the base distribution revenues from which the requested increase is measured. The total revenue on Page 2 ties to the total revenue described by Mr. O'Brien with his revenue adjustments on Exhibit No. 2, Schedule D-1, Page 1. The second step includes rolling DSIC assets into the base distribution rate base, which is included in DSIC eligible FERC accounts within each of Mr. O'Brien's Exhibits (2 through 4), Schedule C-2, Page 3. Mr. O'Brien explains these adjustments in more detail within DLC Statement No. 9.

Q. Please explain the proposed changes to Appendix A – TSC.

A. Appendix A provides the Company the mechanism to charge default service customers for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the FERC. The Company is proposing to update the table for the lighting rate classes in order to accommodate the new LED street lighting fixtures offered.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit No. DBO-1

SUPPLEMENT NO. 174
TO ELECTRIC – PA. P.U.C. NO. 24

DUQUESNE LIGHT CO.

SCHEDULE OF RATES

For Electric Service in Allegheny and Beaver Counties

(For List of Communities Served, see Pages No. 4 and 5)

Issued By

DUQUESNE LIGHT COMPANY
411 Seventh Avenue
Pittsburgh, PA 15219

Richard Riazzi
President and Chief Executive Officer

ISSUED: March 28, 2018 EFFECTIVE: May 29, 2018

Filed at Docket No. R-2018-3000124

NOTICE

THIS TARIFF SUPPLEMENT MAKES CHANGES TO THE TABLE OF CONTENTS, RULES AND REGULATIONS, RATE SCHEDULES, RIDERS AND APPENDIX A AND MAKES INCREASES AND DECREASES TO THE RATES CONTAINED IN THE RATE SCHEDULES, RIDERS AND APPENDIX A.

See Page Two

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

List of Modifications **Page No. 2**

Pages No. 2A through 2R were added to the Tariff.

Table of Contents
Standard Contract Riders

Thirty-Fifth Revised Page No. 3
Cancelling Thirty-Fourth Revised Page No. 3

Pages No. 2A through 2R were added to the Table of Contents.

The Table of Contents has been updated to reflect the addition of Original Page No. 70A.

The Table of Contents has been updated to reflect the addition of Original Page No. 73A.

The Table of Contents has been updated to reflect the addition of Original Page No. 78A.

The Table of Contents has been updated to reflect the removal of Rider No. 4 – Budget Billing HUD Finance Multi-Family Housing. Rider No. 4 has been revised to read "This Page Intentionally Left Blank."

The Table of Contents has been updated to reflect the removal of Rider No. 7 – SECA Charge. Rider No. 7 has been revised to read "This Page Intentionally Left Blank."

Rules and Regulations
The Electric Service Tariff

Fifth Revised Page No. 6
Cancelling Fourth Revised Page No. 6

Rule No. 2.1 Rules and Regulations has been added to clarify tariff applicability to all persons taking service.

Rule No. 2.2 Statement by Agents has been added to clarify that Company representatives cannot modify tariff obligations.

Rule No. 3 Application has been revised to update and define the Company's standard nominal service delivery voltages for installations prior to and effective on January 1, 2019.

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions

Fifth Revised Page No. 6
Cancelling Fourth Revised Page No. 6

Rule No. 3.1 Definitions (1) Aggregator or Market Aggregator and (2) Applicant previously shown on Fourth Revised Page No. 6, Cancelling Third Revised Page No. 6 in Supplement No. 107 has been moved to Sixth Revised Page No. 7, Cancelling Fifth Revised Page No. 7 in Supplement No. 174 to accommodate the addition of and revision to rules.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions

Sixth Revised Page No. 7
Cancelling Fifth Revised Page No. 7

Rule No. 3.1 Definitions along with (1) Aggregator or Market Aggregator and (2) Applicant previously shown on Fourth Revised Page No. 6, Cancelling Third Revised Page No. 6 in Supplement No. 107 has been moved to Sixth Revised Page No. 7, Cancelling Fifth Revised Page No. 7 in Supplement No. 174 to accommodate the addition of and revision to rules.

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions

Sixth Revised Page No. 7
Cancelling Fifth Revised Page No. 7

Language has been revised in Definition (8) Customer to clarify the definition of "Customer."

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions

Sixth Revised Page No. 8
Cancelling Fifth Revised Page No. 8

Currently existing definitions for Rate Ready and Renewable Resource have been moved down to place in alphabetical order.

The definition for Summary Billing has been added.

Definitions have been renumbered to place in alphabetical order and to accommodate the addition of a definition of Summary Billing.

Rules and Regulations
Contracts, Deposits and Advance Payments
4. Contracts

Fourth Revised Page No. 9
Cancelling Third Revised Page No. 9

Language has been inserted at the end of the first sentence of paragraph one to clarify that Nonstandard Service costs can be recoverable through special rate contracts.

Language has been revised to adjust instances where the Company can enter into special rate contracts and the duration of special contracts.

Information previously shown on Second Revised Page No. 9A, Cancelling First Revised Page No. 9A in Supplement No. 72 has been moved to the end of Fourth Revised Page No. 9, Cancelling Third Revised Page No. 9 in Supplement No. 174.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
Contracts, Deposits and Advance Payments — **Second Revised Page No. 9A**
4. Contracts — **Cancelling First Revised Page No. 9A**

Second Revised Page No. 9A, Cancelling First Revised Page No. 9A in Supplement No. 72 is being deleted as it is no longer necessary. Information previously shown on Second Revised Page No. 9A, Cancelling First Revised Page No. 9A in Supplement No. 72 has been moved to the end of Fourth Revised Page No. 9, Cancelling Third Revised Page No. 9 in Supplement No. 174.

Rules and Regulations
Contracts, Deposits and Advance Payments — **Fourth Revised Page No. 10**
5. Deposits and Advance Payments — **Cancelling Third Revised Page No. 10**

Language has been inserted to clarify that EGS charges, where applicable, are included in the calculation of a security deposit.

Language has been inserted to clarify how the Company evaluates creditworthiness of non-residential customers.

Language has been inserted to clarify the Company process for requiring security deposits from non-residential customers.

Rules and Regulations
Contracts, Deposits and Advance Payments — **Second Revised Page No. 10A**
5. Deposits and Advance Payments — **Cancelling First Revised Page No. 10A**

The paragraph referencing "seasonal service" has been removed as obsolete. The Company no longer provides a separate seasonal service rate.

Language has been inserted to explain that security deposit requirements for residential customers do not extend to non-residential accounts.

Rules and Regulations
Payment of Outstanding Balance — **Second Revised Page No. 10A**
5a. Payment of Outstanding Balance — **Cancelling First Revised Page No. 10A**

Language has been inserted to clarify customer/applicant responsibility for outstanding account balances and the documentation required to establish service.

Rules and Regulations
Installation of Service — **Third Revised Page No. 11**
6. Installation Rules — **Cancelling Second Revised Page No. 11**

Language has been inserted to clarify limited exception for Company-approved Nonstandard Service.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
Installation of Service — **Third Revised Page No. 11**
6.1 Service Point — **Cancelling Second Revised Page No. 11**

Rule No. 6.1 Service Point has been added to comply with 52 Pa. Code § 57.28 (a) Electric Safety Standards (Docket No. L-2015-2500632).

Rule No. 7 Supply Line Extensions previously shown on Second Revised Page No. 11, Cancelling First Revised Page No. 11 in Supplement No. 35 has been moved to Original Page No. 11A in Supplement No. 174 in order to accommodate the addition of Rule No. 6.1 Service Point.

Rules and Regulations
Installation of Service
7. Supply Line Extensions — **Original Page No. 11A**

Original Page No. 11A has been added to Tariff No. 24.

Rule No. 7 Supply Line Extensions previously shown on Second Revised Page No. 11, Cancelling First Revised Page No. 11 in Supplement No. 35 has been moved to Original Page No. 11A in Supplement No. 174 in order to accommodate the addition of Rule No. 6.1 Service Point.

Language has been inserted in Rule No. 7 Supply Line Extensions, B. Overhead Areas (1) to provide additional customer clarity in regard to the length of single-phase, lower-voltage supply line extensions.

Rules and Regulations
Installation of Service
7. Supply Line Extensions — **Second Revised Page No. 12**
B. Overhead Areas – (Continued) — **Cancelling First Revised Page No. 12**

Rule No. 7 Supply Line Extensions, B. Overhead Areas (3) has been removed to clarify the Company's ability to recover costs of Nonstandard Service.

Rules and Regulations
Installation of Service
7. Supply Line Extensions — **Second Revised Page No. 13**
C. Underground Areas – (Continued) — **Cancelling First Revised Page No. 13**

Rule No. 7 Supply Line Extensions, C. Underground Areas (3) has been removed to clarify the Company's ability to recover costs of Nonstandard Service.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
Installation of Service
7. Supply Line Extensions
E. Revenue Guarantees

Second Revised Page No. 14
Cancelling First Revised Page No. 14

Language has been inserted to provide that costs other than those associated with service line extensions may be included in a revenue guarantee.

Rules and Regulations
Installation of Service
7. Supply Line Extensions
E. Revenue Guarantees

Second Revised Page No. 14
Cancelling First Revised Page No. 14

Language has been inserted into Rule No. 7 Supply Line Extensions, E. Revenue Guarantees and E. Revenue Guarantees (2) to clarify the revenue guarantee payment and refund process.

Rules and Regulations
Installation of Service
8. Nonstandard Service

Second Revised Page No. 15
Cancelling First Revised Page No. 15

Rule No. 8 Connection Charges as shown on First Revised Page No. 15, Cancelling Original Page No. 15 in Supplement No. 2, has been renamed to Rule No. 8 Nonstandard Service in Supplement No. 174.

Language has been revised and inserted to clarify the Company's ability to recover costs of Nonstandard Service.

Rules and Regulations
Installation of Service
9. Relocations of Facilities

Second Revised Page No. 15
Cancelling First Revised Page No. 15

Rule No. 9 Relocations of Facilities, A. Pole Removal or Relocation for Residential Customers (2), (3) and (4) and B. Other Company Facilities for all Customers previously shown on First Revised Page No. 15, Cancelling First Revised Page No. 15 in Supplement No. 2 has been moved to Original Page No. 15A in Supplement No. 174 in order to accommodate the revisions to Rule No. 8 Nonstandard Service.

Rules and Regulations
Installation of Service
9. Relocations of Facilities – (Continued)

Original Page No. 15A

Original Page No. 15A has been added to Tariff No. 24.

Rule No. 9 Relocations of Facilities, A. Pole Removal or Relocation for Residential Customers (2), (3) and (4) and B. Other Company Facilities for all Customers previously shown on First Revised Page No. 15, Cancelling First Revised Page No. 15 in Supplement No. 2 has been moved to Original Page No. 15A in Supplement No. 174 in order to accommodate the revisions to Rule No. 8 Nonstandard Service.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
Measurement and Use of Service — **Fifth Revised Page No. 22**
14.2 Customer Request for Special Metering – (Continued) — **Cancelling Fourth Revised Page No. 22**

Language has been removed as obsolete.

Rules and Regulations
Measurement and Use of Service — **Fifth Revised Page No. 22**
14.3 Sub-Metering — **Cancelling Fourth Revised Page No. 22**

Rule No. 14.3 Sub-Metering has been removed as unnecessary.

Rules and Regulations
Bills and Net Payment Periods — **Fifth Revised Page No. 23**
18. Redistribution — **Cancelling Fourth Revised Page No. 23**

Language has been modified for clarity.

Rules and Regulations
Bills and Net Payment Periods — **Fifth Revised Page No. 23**
20.2 Summary Billing — **Cancelling Fourth Revised Page No. 23**

Rule No. 20.2 Summary Billing has been added to explain the availability of Summary Bills to qualifying customers.

Rules and Regulations — **Sixth Revised Page No. 23A**
Bills and Net Payment Periods — **Cancelling Fifth Revised Page No. 23A**

Rule No. 20.2 Bills (as numbered in Fifth Revised Page No. 23A, Cancelling Fourth Revised Page No. 23A in Supplement No. 128) has been renumbered to Rule No. 20.3 and Rule No. 20.3 Budget Payment Plan for Residential Customers (as numbered in Fifth Revised Page No. 23A, Cancelling Fourth Revised Page No. 23A in Supplement No. 128) has been renumbered to Rule No. 20.4 to accommodate the addition of Rule No. 20.2 Summary Billing in Supplement No. 174.

Rules and Regulations
Bills and Net Payment Periods — **Sixth Revised Page No. 23A**
20.4 Budget Payment Plan for Residential Customers — **Cancelling Fifth Revised Page No. 23A**

Language has been inserted to clarify budget billing for customers of bill-ready EGSs.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations
Company Property on Customer's Premises — **Fifth Revised Page No. 24**
22 Access to Premises — **Cancelling Fourth Revised Page No. 24**

Language has been inserted to ensure Company access to facilities, particularly in the event of emergency, and to clarify that failure to provide access is grounds for termination.

Rules and Regulations
Company Property on Customer's Premises — **Fifth Revised Page No. 24**
22.1 Vegetation Management and Right-Of-Way — **Cancelling Fourth Revised Page No. 24**

Rule No. 22.1 Vegetation Management and Right-Of-Way has been added to clarify customer and Company responsibilities regarding vegetation management around Company facilities.

Rules and Regulations
Company Property on Customer's Premises — **Fifth Revised Page No. 24**
25 Repairs or Losses — **Cancelling Fourth Revised Page No. 24**

Rule No. 25 Repairs or Losses previously shown on Fourth Revised Page No. 24, Cancelling Third Revised Page No. 24 in Supplement No. 100 has been moved to First Revised Page No. 24A, Cancelling Original Page No. 24A in Supplement No. 174 in order to accommodate the addition of Rule No. 22.1 Vegetation Management and Right-Of-Way.

Rules and Regulations — **First Revised Page No. 24A**
Discontinuance, Curtailment or Interruption of Electric Service — **Cancelling Original Page No. 24A**

The "Bills and Net Payment Periods – (Continued)" heading has been removed as it is not applicable to the section.

Rules and Regulations
Company Property on Customer's Premises — **First Revised Page No. 24A**
25 Repairs or Losses — **Cancelling Original Page No. 24A**

Rule No. 25 Repairs or Losses previously shown on Fourth Revised Page No. 24, Cancelling Third Revised Page No. 24 in Supplement No. 100 has been moved to First Revised Page No. 24A, Cancelling Original Page No. 24A in Supplement No. 174 in order to accommodate the addition of Rule No. 22.1 Vegetation Management and Right-Of-Way.

Rules and Regulations
Discontinuance, Curtailment or Interruption of Electric Service — **Third Revised Page No. 25**
27.1 Death of A Residential Customer — **Cancelling Second Revised Page No. 25**

Rule No. 27.1 Death of A Residential Customer has been added to clarify the Company's process for ending service in the name(s) of customers reported as deceased.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations
Discontinuance, Curtailment or Interruption of Electric Service — **Second Revised Page No. 26**
33 Inaccessibility — **Cancelling First Revised Page No. 26**

Language has been revised and inserted to clarify that failure to provide Company representatives access to Company facilities is grounds for termination, consistent with Rule No. 22.

Rules and Regulations
General Provisions — **Fourth Revised Page No. 31A**
46. Provision of Load Data — **Cancelling Third Revised Page No. 31A**

Language has been modified to reflect current business practice. Rule No. 46 has been revised to comply with Commission Order dated October 11, 2012, at Docket No. R-2012-2320394. The reference to "once each calendar year" has been updated to "five (5) requests in a calendar year."

Rate GS/GM – General Service Small and Medium — **Eighth Revised Page No. 40**
Cancelling Seventh Revised Page No. 40

Seventh Revised Page No. 42
Cancelling Sixth Revised Page No. 42

The design of the Monthly Rate section, including sub-section titling, has been modified for customer clarity.

Rate GS/GM – General Service Small and Medium — **Eighth Revised Page No. 41**
Cancelling Seventh Revised Page No. 41

Language has been modified to clarify customer rate assignments among Rate GS, Rate GM < 25 kW and Rate GM ≥ 25 kW.

The last three paragraphs of the "Electric Charges" section as well as the "Minimum Charge" section previously shown on Seventh Revised Page No. 41, Cancelling Sixth Revised Page No. 41 in Supplement No. 35 has been moved to Seventh Revised Page No. 42, Cancelling Sixth Revised Page No. 42 in Supplement No. 174 to accommodate the addition of the rate assignment language.

Rate GS/GM – General Service Small and Medium — **Seventh Revised Page No. 42**
Cancelling Sixth Revised Page No. 42

The last three paragraphs of the "Electric Charges" section as well as the "Minimum Charge" section previously shown on Seventh Revised Page No. 41, Cancelling Sixth Revised Page No. 41 in Supplement No. 35 has been moved to Seventh Revised Page No. 42, Cancelling Sixth Revised Page No. 42 in Supplement No. 174 to accommodate the addition of the rate assignment language.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate GMH – General Service Medium Heating

Eighth Revised Page No. 43
Cancelling Seventh Revised Page No. 43

Ninth Revised Page No. 44
Cancelling Eighth Revised Page No. 44

The design of the Monthly Rate section has been modified for customer clarity.

Rate GMH – General Service Medium Heating

Ninth Revised Page No. 44
Cancelling Eighth Revised Page No. 44

Language has been modified to clarify customer rate assignments between Rate GM < 25 kW and Rate GM ≥ 25 kW.

Rate GL – General Service Large

Eighth Revised Page No. 47
Cancelling Seventh Revised Page No. 47

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate GLH – General Service Large Heating

Eighth Revised Page No. 50
Cancelling Seventh Revised Page No. 50

Fifth Revised Page No. 51
Cancelling Fourth Revised Page No. 51

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate L – Large Power Service

Eighth Revised Page No. 53
Cancelling Seventh Revised Page No. 53

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate L – Large Power Service

Eighth Revised Page No. 53
Cancelling Seventh Revised Page No. 53

Language and relevant rate charges have been removed as "Service Voltage 138 kV and Greater" is no longer applicable to Rate L – Large Power Service.

Rate L – Large Power Service

Second Revised Page No. 56
Cancelling First Revised Page No. 56

Language has been modified from "his" to "its."

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate HVPS – High Voltage Power Service **Eighth Revised Page No. 57**
Cancelling Seventh Revised Page No. 57

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate HVPS – High Voltage Power Service **Eighth Revised Page No. 57**
Cancelling Seventh Revised Page No. 57

Fourth Revised Page No. 58
Cancelling Third Revised Page No. 58

Second Revised Page No. 60
Cancelling First Revised Page No. 60

Language has been modified to lower the kilowatts from "greater than 30,000" to "greater than "5,000" in order to move Rate L – Large Power Service 138 kV and Greater customers to Rate HVPS – High Voltage Power Service.

Rate HVPS – High Voltage Power Service **Second Revised Page No. 60**
Cancelling First Revised Page No. 60

Language has been modified from "his" to "its."

Rate AL – Architectural Lighting Service **Second Revised Page No. 63**
Cancelling First Revised Page No. 63

Item No. 5 under the "Special Terms and Conditions" section has been removed as the Company no longer provides a separate seasonal service rate.

Rate SM – Street Lighting Municipal **Ninth Revised Page No. 68**
Cancelling Eighth Revised Page No. 68

Language has been inserted to reflect the availability of replacement of mercury vapor lamps, fixtures or luminaries, including brackets and ballasts, beginning January 1, 2019.

Language has been inserted as to the minimum number of LED lights per customer, per order requirement and the contiguous location requirement when replacing existing lighting.

Language has been inserted as to the maximum LED light installations the Company shall be required to perform annually.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SM – Street Lighting Municipal

Ninth Revised Page No. 68
Cancelling Eighth Revised Page No. 68

Eighth Revised Page No. 69
Cancelling Seventh Revised Page No. 69

Columns in the Monthly Rate section have been updated to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

Rate SM – Street Lighting Municipal

Eighth Revised Page No. 69
Cancelling Seventh Revised Page No. 69

Current LED lamp wattages have been removed as obsolete.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

The last three (3) paragraphs under "Electric Charges" that resided on Seventh Revised Page No. 69, Cancelling Sixth Revised Page No. 69 in Supplement No. 91 have been moved to Fifth Revised Page No. 70, Cancelling Fourth Revised Page No. 70 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

Rate SM – Street Lighting Municipal

Fifth Revised Page No. 70
Cancelling Fourth Revised Page No. 70

The Rate Schedule name in the header has been revised to read "Lighting."

The last three (3) paragraphs under "Electric Charges" that resided on Seventh Revised Page No. 69, Cancelling Sixth Revised Page No. 69 in Supplement No. 91 have been moved to Fifth Revised Page No. 70, Cancelling Fourth Revised Page No. 70 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

The "Special Terms and Conditions" section that resided on Fourth Revised Page No. 70, Cancelling Third Revised Page No. 70 in Supplement No. 155 has been moved to Original Page No. 70A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SM – Street Lighting Municipal.

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate SM – Street Lighting Municipal.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SM – Street Lighting Municipal **Original Page No. 70A**

Original Page No. 70A has been added in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SM – Street Lighting Municipal.

The "Special Terms and Conditions" section originally shown on Fourth Revised Page No. 70, Cancelling Third Revised Page No. 70 in Supplement No. 155 has been moved to Original Page No. 70A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SM – Street Lighting Municipal.

Item No. 5 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate SM – Street Lighting Municipal.

Rate SH – Street Lighting Highway **Ninth Revised Page No. 71**
Cancelling Eighth Revised Page No. 71

Columns in the Monthly Rate section have been updated to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

New LED lamp wattages have been inserted as choices for Cobra Head fixtures.

The first three (3) paragraphs under "Electric Charges" that resided on Eighth Revised Page No. 71, Cancelling Seventh Revised Page No. 71 in Supplement No. 155 have been moved to Third Revised Page No. 72, Cancelling Second Revised Page No. 72 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

Rate SH – Street Lighting Highway **Third Revised Page No. 72**
Cancelling Second Revised Page No. 72

The first three (3) paragraphs under "Electric Charges" that resided on Eighth Revised Page No. 71, Cancelling Seventh Revised Page No. 71 in Supplement No. 155 have been moved to Third Revised Page No. 72, Cancelling Second Revised Page No. 72 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

Rate SH – Street Lighting Highway **Third Revised Page No. 72**
Cancelling Second Revised Page No. 72

The "Special Terms and Conditions" section that resided on Second Revised Page No. 72, Cancelling First Revised Page No. 72 in Supplement No. 72 has been moved to Second Revised Page No. 73, Cancelling First Revised Page No. 73 in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate SH – Street Lighting Highway.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SH – Street Lighting Highway **Second Revised Page No. 73**
Cancelling First Revised Page No. 73

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate SH – Street Lighting Highway.

The "Special Terms and Conditions" section that resided on Second Revised Page No. 72, Cancelling First Revised Page No. 72 in Supplement No. 72 has been moved to Second Revised Page No. 73, Cancelling First Revised Page No. 73 in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

Language has been modified to remove "230/460 volts" in Item No. 2 under the "Special Terms and Conditions" section.

Rate SH – Street Lighting Highway **Original Page No. 73A**

Original Page No. 73A has been added to Tariff No. 24 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

The "Special Terms and Conditions" section that resided on First Revised Page No. 73, Cancelling Original Page No. 73 in Supplement No. 2 has been moved to Original Page No. 73A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

Item No. 9 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate SH – Street Lighting Highway.

The "Term of Contract" section that resided on First Revised Page No. 73, Cancelling Original Page No. 73 in Supplement No. 2 has been moved to Original Page No. 73A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

Rate PAL – Private Area Lighting **Ninth Revised Page No. 76**
Cancelling Eighth Revised Page No. 76

Columns in the Monthly Rate section have been updated and revised to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate PAL – Private Area Lighting

Fifth Revised Page No. 77
Cancelling Fourth Revised Page No. 77

The "Supply Charges" section that resided on Eighth Revised Page No. 76, Cancelling Seventh Revised Page No. 76 in Supplement No. 155 has been moved to Fifth Revised page No. 77, Cancelling Fourth Revised Page No. 77 in Supplement No. 174 to accommodate the new LED lamp wattages that have been added to Rate PAL – Private Area Lighting.

Language has been modified to correct the reference from "UMS – Unmetered Service" to "PAL – Private Area Lighting."

Rate PAL – Private Area Lighting

Sixth Revised Page No. 78
Cancelling Fifth Revised Page No. 78

The "Special Terms and Conditions" section that resided on Fifth Revised Page No. 78, Cancelling Fourth Revised Page No. 78 in Supplement No. 155 has been moved to Original Page No. 78A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate PAL – Private Area Lighting.

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate PAL – Private Area Lighting.

Rate PAL – Private Area Lighting

Original Page No. 78A

Original Page No. 78A has been added to Tariff No. 24 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate PAL – Private Area Lighting.

The "Special Terms and Conditions" section that resided on Fifth Revised Page No. 78, Cancelling Fourth Revised Page No. 78 in Supplement No. 155 has been moved to Original Page No. 78A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate PAL – Private Area Lighting.

Item No. 5 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate PAL – Private Area Lighting.

Standard Contract Riders
Rider Matrix

Seventh Revised Page No. 79A
Cancelling Sixth Revised Page No. 79A

The Rider Matrix has been revised to show the removal of Rider No. 4 – Budget Billing HUD Finance Multi-Family Housing and Rider No. 7 – SECA Charge. The Riders now read "Intentionally Left Blank."

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 1 – Retail Market Enhancement Surcharge **Nineteenth Revised Page No. 80**
Cancelling Eighteenth Revised Page No. 80

Rider No. 1 – Retail Market Enhancement Surcharge has been modified to remove the recovery of the Purchase of Receivables ("POR") program discount expense associated with the uncollectible expense of EGS consolidated billings. In accordance with Docket No. P-2016-2543140, the expense is being rolled into and recovered through base rates.

Rider No. 1 – Retail Market Enhancement Surcharge **Nineteenth Revised Page No. 80**
Cancelling Eighteenth Revised Page No. 80

Fifth Revised Page No. 80A
Cancelling Fourth Revised Page No. 80A

In the "Calculation of Rates" section, reference to Purchase of Receivables ("POR") has been removed from the formula and the definition.

Rider No. 4 – Budget Billing HUD Financed Multi Family Housing **Second Revised Page No. 83**
Cancelling First Revised Page No. 83

Rider No. 4 – Budget Billing HUD Financed Multi-Family Housing is being removed as obsolete.

Rider No. 5 – Universal Service Charge **Fourteenth Revised Page No. 84**
Cancelling Thirteenth Revised Page No. 84

Rider No. 5 – Universal Service Charge **Sixth Revised Page No. 85**
Cancelling Fifth Revised Page No. 85

Language in the "Calculation of Charge" section has been revised. This language was included in the tariff to address a prior CAP Plus proposal. The Company does not have a CAP Plus plan; therefore, it is appropriate to remove this language.

Rider No. 5 – Universal Service Charge **Sixth Revised Page No. 85**
Cancelling Fifth Revised Page No. 85

Language in the "Calculation of Charge" section has been revised. Pursuant to the Company's 2017-2019 Universal Service and Energy Conservation Plan, customers who receive a LIHEAP grant are no longer auto-enrolled in CAP. The elimination of the Company's auto-enrollment program was approved by Commission Order entered March 23, 2017 at Docket Number M-2016-2534323.

The CAP participation level has been reset as per the provisions of Rider No. 5.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 7 – SECA Charge — **Third Revised Page No. 87**
Cancelling Second Revised Page No. 87

Rider No. 7 – SECA Charge is being removed as the charges are being recovered through the Company's Appendix A – Transmission Service Charges ("TSC").

Rider No. 8 – Default Service Supply — **Third Revised Page No. 88A-1**
Cancelling Second Revised Page No. 88A-1

A new application period is reflected in the heading and added to the chart to reflect the addition of LED lighting.

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

Rider No. 8 – Default Service Supply — **First Revised Page No. 88A-2**
Cancelling Original Page No. 88A-2

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

Rider No. 8 – Default Service Supply — **Sixth Revised Page No. 88C**
Cancelling Fifth Revised Page No. 88C

In the "Calculation of Rates" section, the Docket No. has been updated in DSSa.

Rider No. 9 – Day-Ahead Hourly Price Service — **Sixth Revised Page No. 91**
Cancelling Fifth Revised Page No. 91

Under "Fixed Retail Administrative Charge" section, the Docket No. has been updated in FRA.

Rider No. 10 – State Tax Adjustment — **Fourteenth Revised Page No. 94**
Cancelling Thirteenth Revised Page No. 94

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

Rider No. 13 – General Service Separately Metered Electric Space Heating Service — **Fifth Revised Page No. 97**
Cancelling Fourth Revised Page No. 97

The word "metered" has been removed in the paragraph under "Energy Charges."

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 16 – Service to Non-Utility Generating Facilities — **Sixth Revised Page No.101**
Cancelling Fifth Revised Page No. 101

Sixth Revised Page No.102
Cancelling Fifth Revised Page No. 102

Language has been revised and inserted to clarify the service being provided and the definition of billing determinates.

Rider No. 20 – Smart Meter Charge — **Thirty-Seventh Revised Page No. 108**
Cancelling Thirty-Sixth Revised Page No. 108

Rider No. 20 – Smart Meter Charge has been modified to reflect that it has been set to zero.

Rider No. 21 – Net Metering Service — **Fourth Revised Page No. 110**
Cancelling Third Revised Page No. 110

Language has been revised and inserted to require the installation of a generation meter to measure actual customer-generator facility output to accommodate and plan for increased saturation of net metered installations.

Rider No. 22 – Distribution System Improvement Charge — **Seventh Revised Page No. 112B**
Cancelling Sixth Revised Page No. 112B

Rider No. 22 – Distribution System Improvement Charge ("DSIC") has been modified to reflect that it has been set to zero.

Appendix A – Transmission Service Charges — **Eleventh Revised Page No. 114**
Cancelling Tenth Revised Page No. 114

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

INCREASES

Rate RS – Residential Service — **Ninth Revised Page No. 32**
Cancelling Eighth Revised Page No. 32

Rate RH – Residential Service Heating — **Ninth Revised Page No. 34**
Cancelling Eighth Revised Page No. 34

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rate RA – Residential Service Add-On Heat Pump	Ninth Revised Page No. 37 Cancelling Eighth Revised Page No. 37
Rate GS/GM – General Service Small and Medium	Eighth Revised Page No. 40 Cancelling Seventh Revised Page No. 40
Rate GMH – General Service Medium Heating	Eighth Revised Page No. 43 Cancelling Seventh Revised Page No. 43
Rate GMH – General Service Medium Heating	Eighth Revised Page No. 45 Cancelling Seventh Revised Page No. 45
Rate GL – General Service Large	Eighth Revised Page No. 47 Cancelling Seventh Revised Page No. 47
Rate GLH – General Service Large Heating	Eighth Revised Page No. 50 Cancelling Seventh Revised Page No. 50
Rate GLH – General Service Large Heating	Fifth Revised Page No. 51 Cancelling Fourth Revised Page No. 51
Rate L – Large Power Service	Eighth Revised Page No. 53 Cancelling Seventh Revised Page No. 53
Rate AL – Architectural Lighting Service	Ninth Revised Page No. 61 Cancelling Eighth Revised Page No. 61
Rate SE – Street Lighting Energy	Ninth Revised Page No. 64 Cancelling Eighth Revised Page No. 64
Rate SM – Street Lighting Municipal	Ninth Revised Page No. 68 Cancelling Eighth Revised Page No. 68
Rate SM – Street Lighting Municipal	Fifth Revised Page No. 70 Cancelling Fourth Revised Page No. 70
Rate SH – Street Lighting Highway	Ninth Revised Page No. 71 Cancelling Eighth Revised Page No. 71
Rate PAL – Private Area Lighting	Ninth Revised Page No. 76 Cancelling Eighth Revised Page No. 76
Rate PAL – Private Area Lighting	Sixth Revised Page No. 78 Cancelling Fifth Revised Page No. 78

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rider No. 10 – State Tax Adjustment	**Fourteenth Revised Page No. 94** **Cancelling Thirteenth Revised Page No. 94**
Rider No. 16 – Service to Non-Utility Generating Facilities	**Sixth Revised Page No.102** **Cancelling Fifth Revised Page No. 102**

Unit prices have changed, resulting in increases.

DECREASES

Rate HVPS – High Voltage Power Service	**Eighth Revised Page No. 57** **Cancelling Seventh Revised Page No. 57**
Rate UMS – Unmetered Service	**Ninth Revised Page No. 74** **Cancelling Eighth Revised Page No. 74**
Rate PAL – Private Area Lighting	**Ninth Revised Page No. 76** **Cancelling Eighth Revised Page No. 76**
Rider No. 1 – Retail Market Enhancement Surcharge	**Nineteenth Revised Page No. 80** **Cancelling Eighteenth Revised Page No. 80**
Rider No. 20 – Smart Meter Charge	**Thirty-Seventh Revised Page No. 108** **Cancelling Thirty-Sixth Revised Page No. 108**
Rider No. 22 – Distribution System Improvement Charge	**Seventh Revised Page No. 112B** **Cancelling Sixth Revised Page No. 112B**

Unit prices have changed, resulting in decreases.

TABLE OF CONTENTS

(C) – Indicates Change

RULES AND REGULATIONS

THE ELECTRIC SERVICE TARIFF

1. **FILING AND POSTING** A copy of the Tariff, comprising of the Rules and Regulations, Rates and Riders, and governing electric service, is filed with the Pennsylvania Public Utility Commission. A copy of the Tariff may be obtained by calling, e-mailing or writing the Company's business office. The Tariff may also be accessed at www.duquesnelight.com and is posted and open to inspection at the offices of the Company where payments are made by customers.

2. **REVISIONS** The tariff is subject to such change and modification as may be made from time to time in the manner prescribed by the Public Utility Law. If any rate for electric service is increased, the affected customer shall have the option of discontinuing service, but shall be obligated to pay the increased rate from the effective date thereof until service has been discontinued.

2.1 **RULES AND REGULATIONS** The Rules and Regulations, filed as part of this Tariff, are a part of every (C)
contract for service made by the Company and govern all classes of service where applicable. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service.

2.2 **STATEMENT BY AGENTS** No representative has authority to modify a Tariff rule or provision, or to bind (C)
the Company by any promise or representation contrary thereto.

3. **APPLICATION** Rates of the tariff apply only to the Company's Standard Service delivered from overhead supply lines except in certain restricted areas where the Company is required to provide underground distribution. Riders of the tariff amend or modify the terms governing the electric service under the rates to which they apply. Beginning January 1, 2019, Standard Service is alternating current of sixty cycles frequency, conforming as to (C)
voltage and phase with the following list of standard nominal service delivery voltages.

SINGLE-PHASE	THREE-PHASE		
120/240 volts, 3 wire	120/208 volts, 4 wire	23,000 volts, 3 wire	
480 volts, 2 wire	277/480 volts, 4 wire	13,200/23,000 volts, 4 wire	(C)
13,200 volts, 2 wire	2,400 volts, 3 wire	138,000 volts, 3 wire	(C)
	2,400/4,160 volts, 4 wire		

For service installations completed prior to January 1, 2019, Standard Service may include the delivery voltages (C)
listed above as well as the following list of standard nominal service delivery voltages, as applicable.

SINGLE-PHASE	THREE-PHASE	(C)
120 volts, 2 wire	230 volts, 3 wire	
120/208 volts, 3 wire	460 volts, 3 wire	
230 volts, 2 wire	11,500 volts, 3 wire	
460 volts, 2 wire	69,000 volts, 3 wire	
230/460 volts, 3 wire	345,000 volts, 3 wire	
2,400 volts, 2 wire		
23,000 volts, 2 wire		

The supply of electricity may be provided by the Company or by an alternative Electric Generation Supplier ("EGS"). Rates for the supply of electricity shall apply per applicable tariffs of the Company or the EGS.

(C)

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

THE ELECTRIC SERVICE TARIFF - (Continued)

3.1 DEFINITIONS (C)

(1) **Aggregator or Market Aggregator** – An entity, licensed by the Commission, which purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers. (C)

(2) **Applicant** – A natural person not currently receiving service who applies for residential service provided by a public utility or any adult occupant whose name appears on the mortgage, deed or lease of the property for which the residential utility service is requested. The term does not include a person who, within thirty (30) days after service termination or discontinuance of service, seeks to have service reconnected at the same location or transferred to another location within the service territory of the Company. (C)

(3) **Basic Services** – The services necessary for the physical delivery of electricity service such as supply, including default service, transmission and distribution. Unless directed otherwise, "electric service" or "service" used throughout this tariff have the same meaning.

(4) **Bill Ready** – A form of consolidated billing where Duquesne Light provides a customer's usage to its electric generation supplier ("EGS") and the EGS then calculates the customer's charges and sends the line item(s) back to the Company to be presented on the supplier portion of the bill.

(5) **Broker or Marketer** – An entity, licensed by the Commission, which acts as an agent or intermediary in the sale and purchase of electric energy but does not take title to electric energy.

(6) **Commission** – The Pennsylvania Public Utility Commission.

(7) **Company** - Duquesne Light Company.

(8) **Customer** –Any person, partnership, association, corporation or other legal entity lawfully receiving service from the Company. Unless indicated otherwise, "retail customer" and "customer" used throughout this tariff shall have the same meaning. A residential customer is a natural person in whose name a residential service account is listed and who is primarily responsible for payment of bills rendered for the service or any adult occupant whose name appears on the mortgage, deed or lease of the property of which the residential utility service is requested. The term includes a person who, within thirty (30) days after service termination or discontinuance of service, seeks to have service reconnected at the same location or transferred to another location within the service territory of the public utility. (C)

(9) **Default Service** – The Company will provide electricity to the customer in the event that a customer: 1) elects not to obtain electricity from an EGS; 2) elects to have the Company supply electricity after having previously purchased electricity from an EGS; 3) contracts with an EGS who fails to supply electricity, or 4) has been returned to Default Service by the EGS under circumstances as described in Rule No. 45.2 of this tariff.

(10) **Direct access** – The right of EGSs and retail customers to utilize and interconnect with the electric transmission and distribution system of the Company on a non-discriminatory basis at rates and terms and conditions of service comparable to the Companies' own use of the system to transport electricity from any generator of electricity to any retail customer.

(11) **Distribution Charges** – Basic service charges for delivering electricity over a distribution system (e.g. wires, transformers, substations and other equipment) to the home or business from the transmission system. The distribution charge is regulated by the Commission. These charges include basic service under 52 Pa. Code §56.15 (4) (relating to billing information) and Riders, as applicable.

(12) **Electric Distribution Company ("EDC")** – An entity, including Duquesne Light Company ("Company"), owning and providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners or operators that manage the internal distribution system serving such building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

RULES AND REGULATIONS - (Continued)

THE ELECTRIC SERVICE TARIFF - (Continued)

3.1 DEFINITIONS - (Continued)

(13) Electric Generation Suppliers ("EGS") – A person or corporation, including municipal corporation, which provides service outside its municipal limits except to the extent provided prior to January 1, 1997. This includes brokers and marketers, aggregators or any other entities that sell to end-use customers electricity or related services utilizing the jurisdictional transmission or distribution facilities of an electric distribution company. The term excludes building or facility owner/operators that manage the internal distribution system for the building or facility and that supply electric power and other related power services to occupants of the building or facility. The term also excludes electric cooperative corporations except as provided in 15 Pa. C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives).

(14) Electricity Provider - The term refers collectively to the EDC, EGS, electricity supplier, marketer, aggregator and/or broker, as well as any third party acting on behalf of these entities.

(15) Non-Basic Services - Optional recurring services which are distinctly separate and clearly not required for the physical delivery of electric service.

(16) PJM – PJM Interconnection, L.L.C. **(C)**

(17) PJM Tariff - The PJM Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission ("FERC") and which sets forth the rates, terms and conditions of transmission service over transmission facilities located in the PJM Control Area. **(C)**

(18) Rate Ready – A form of consolidated billing where Duquesne Light calculates the charge to be presented on the supplier portion of the bill based upon the rates previously supplied by the electric generation supplier ("EGS"). **(C)**

(19) Renewable Resource - Includes technologies such as solar photovoltaic energy, solar thermal energy, wind power, low-head hydropower, geothermal energy, landfill or other biomass-based methane gas, mine-based methane gas, energy from waste and sustainable biomass energy. **(C)**

(20) Summary Bill - An aggregate bill prepared for two or more meter locations owned or legally controlled by the same customer for charges for electric service. **(C)**

(21) Supply Charges - Basic service charges for acquiring or producing electricity for supply to retail customers. This excludes charges for transmission or other charges related to electric service. **(C)**

(22) Transmission Charges - Basic charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system of the Company billed to customers that acquire their electricity from the Company. Customers who choose to acquire electricity from an EGS will be billed for transmission services by the EGS. **(C)**

3.2 ELECTRIC GENERATION SUPPLIER TARIFF The rules and guidelines provided in the Company's "Electric Generation Supplier Coordination Tariff" (Supplier Tariff) shall apply to EGS's accessing the Company's transmission and distribution systems to supply electricity to retail customers. Those rules and guidelines pertaining to direct access procedures shall apply accordingly to customers who elect to purchase part or all of their electricity from an EGS. Copies of these rules may be obtained by calling, e-mailing or writing the Company's business office. In addition, they may also be accessed at www.duquesnelight.com and are posted and open to inspection at the offices of the Company where payments are made by customers.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS

4. **CONTRACTS** The Company reserves the right to require non-residential customers to sign a written contract indicating the rate for electric service and to require a contract term which, in the judgment of the Company, is sufficient to justify the cost of any facilities installed for the exclusive use of the customer and to **(C)** compensate the Company for other incremental costs of Nonstandard Service. Customers who have facilities extended for their exclusive use will be permitted to purchase electricity from an EGS according to the provisions of direct access and 66 Pa.C.S. § 2807. Extension of such facilities will not be conditioned on the customer's agreement to purchase supply from the Company. Receipt of electric service by any entity, however, shall constitute the receiver a customer of the Company, subject to its rules and regulations, whether service is based upon contract, agreement, accepted signed application or otherwise. The customer shall notify the Company, in advance of receipt of electric service, of the customer's name, address to which the electricity is to be delivered, the address to which the bill is to be mailed, the date delivery of electricity is to commence, and provide information requested by the Company regarding the customer's credit standing. The customer shall notify the Company to cancel electric service and the customer shall be responsible for payment for all electric charges until the customer has so notified the Company to cancel electric service.

The Company at its sole discretion may enter into special contracts for electric service with industrial or commercial customers to address changing business needs, operating conditions or less expensive competitive **(C)** alternatives for energy. If requested by the Company, the customer shall provide to the Company, on a **(C)** confidential basis, all information, records and financial analysis necessary to evaluate the customer's request for a special contract.

Terms and conditions of service will be mutually agreed upon by the Company and the customer and included in a signed contract, which will be filed with the Public Utility Commission. The Company at its sole discretion may request Public Utility Commission approval. The terms of the agreement will be confidential upon filing with the Commission. Rates established under special contracts will be sufficient to recover, at a minimum, all appropriate incremental costs. Any special contracts written to become effective on or after January 1, 2007, shall apply only to charges for the distribution service provided by the Company.

The contract shall contain all terms and conditions and the rates and charges to be paid for electric service.

The contract shall be for a period of no less than one (1) year and no greater than ten (10) years. **(C)**

The contract will be terminated by the Company if the Company charges are not paid when due as specified in Tariff Rule No. 21, before the addition of the Late Payment Charge. Upon termination of the contract under these conditions, the regular electric tariff rates will be applied to electric service rendered from that point forward. A new special contract will not be made available to a customer whose previous special contract was terminated because of failure to pay bills as specified in Tariff Rule No. 21.

(C)

For contracts that contain provisions governing the customer's rights under direct access, the Company will unbundle the customer's contract and the customer will be eligible to obtain electricity from an EGS only in accordance with the terms and conditions of the customer's contract. Upon expiration of their contract, special contract customers will default to Rider No. 9 – Day-Ahead Hourly Price Service. **(C)**

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

5. **DEPOSITS AND ADVANCE PAYMENTS** The Company reserves the right to require a cash deposit from applicants taking service for a period of less than thirty (30) days, in an amount equal to the estimated gross bill for Company charges, including applicable EGS charges, for such temporary service. The gross bill for Company charges shall include all fixed, demand and energy charges for Company charges in accordance with the applicable tariff. Deposits may be required from all other applicants when creditworthiness has not been established. A deposit may also be required from existing customers when such customer's credit standing is impaired by delinquent payments of any two (2) consecutive electric bills for Company charges or three (3) or more electric bills for Company charges within the preceding twelve (12) months, or as a condition to the reconnection of service or failure to comply with a payment arrangement. Company charges include the customer's EGS receivables that are purchased by the Company. The Company shall not require an applicant or customer who is confirmed to be eligible for a customer assistance program to provide a cash deposit. (C)

The Company, at its discretion, may deem a non-residential customer or applicant to be not creditworthy. Evidence that such a customer or applicant is not creditworthy may include, but shall not be limited to, where the customer or applicant: (i) is insolvent (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due); (ii) has a class of publicly-traded debt outstanding that is rated to be below investment grade; (iii) has tendered two (2) or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. § 3502, within the last twelve (12) billing cycles; or (iv) has had an account balance at least sixty (60) days in arrears within the last twelve (12) billing cycles. The Company may require non-residential customers or applicants to provide financial data as reasonably necessary for the Company to assess their creditworthiness. (C)

The Company may also use an applicant or customer credit score from a third party credit agency as a means to establish creditworthiness. The credit score in the report will be based in part on previous utility billing history and will use a commercially recognized credit scoring methodology that is within the range of generally accepted industry practices to determine whether security or advance payments are required to establish service. The Company may request a government issued photo ID of any applicant to verify the application.

Where the Company requires a deposit, the amount of the deposit will be based on Company charges in an amount that is equal to one-sixth of the applicant's estimated annual bill or one-sixth of the actual average annual bill for existing customers at the premises, provided that the minimum deposit amount for non-residential customers shall be $250.00. In accordance with Commission regulations, the deposit shall be payable during the 90-day period commencing when the Company determines a deposit is required whether for new service or for deposits required upon reconnection of service as described in Rule No. 40. Failure to pay a required deposit within the time period noted above may result in termination of service consistent with Commission regulations. An applicant or existing customer may furnish a third party guarantor in lieu of a cash deposit, with the provision of a written guaranty setting forth the terms therein. The guarantor will be responsible for all missed payments of the applicant or customer. (C) (C)

The Company will pay interest on residential cash deposits computed at the simple annual interest rate determined by the Commonwealth of Pennsylvania's Secretary of Revenue. The interest rate in effect when the deposit is required to be paid shall remain in effect until the later of the date the deposit is refunded or credited or December 31. On January 1 of each year, the new interest rate for that year will apply to the deposit. For all other cash deposits, the Company will pay interest at the lower of the average of 1-year Treasury Bills for September, October and November of the previous year beginning May 1, 1995 and January 1, 1996 and each year thereafter, or six percent per annum without deduction for any taxes thereon, provided that interest accrued prior to April 14, 1995 shall be calculated at 6%. On deposits held for more than one year, accrued interest will be paid at the end of each anniversary year. Upon the return of a deposit, any unpaid interest accrued thereon will be paid.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

5. DEPOSITS AND ADVANCE PAYMENTS - (Continued)

Deposits secured from a residential applicant or customer shall be returned to the depositor when a timely payment history has been established. A timely payment history is established when a customer has paid undisputed bills in full and on time for twelve (12) consecutive months. Should a customer become delinquent prior to establishing a timely payment history, the Company may deduct the outstanding balance from the deposit. Deposits secured from other than residential customers shall be returned to the depositor upon annual review provided such depositor shall have paid undisputed bills during those consecutive twelve (12) months without having service terminated and without having paid the bill subsequent to the due date so long as the customer is not currently delinquent. Payment of any disputed bill, where the payment is withheld beyond the due date set forth on the face of the bill at issue and the dispute over which is terminated substantially in favor of the customer, shall be made by the customer within fifteen (15) days following the termination of that dispute in order to be deemed timely. Where service is discontinued, the deposit and unpaid interest accrued thereon to the date of discontinuance of service, less the amount of all bills due the Company, will promptly be paid to the customer.

(C)

For purposes of all of the provisions of this Rule No. 5, when a customer resides at a place of business or commercial establishment, legitimately served pursuant to a commercial or industrial rate schedule, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Pennsylvania Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to deposits for residential customers. (C)

PAYMENT OF OUTSTANDING BALANCE

5a. PAYMENT OF OUTSTANDING BALANCE As a condition of the furnishing of service to an applicant or (C)
customer, the payment of any outstanding account amount with the Company for which the applicant or customer (C)
is legally responsible is required. The Company may require the payment of an outstanding balance or portion of
an outstanding balance as a condition of furnishing service if the applicant or customer resided at the property (C)
during the time the outstanding balance accrued and for the time applicant/customer resided there, not exceeding (C)
four (4) years from the date that the last bill rendered, except for fraud or theft. The Company may require the (C)
applicant or customer to provide, and may establish that an applicant or customer previously resided at a property (C)
for which residential service is requested through the use of a mortgage, deed or lease or a commercially
available consumer credit reporting service. In addition, the Company may also require and use valid (C)
government-issued photo identification, and may use billing/mailing records, court records, factual reporting and (C)
Company records where the applicant or customer was listed as a spouse or an occupant of a premise, such as
on a customer assistance program enrollment form, a payment arrangement, a power of attorney or authorization
or a medical certification.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE

6. INSTALLATION RULES Except for Nonstandard Service expressly approved in advance by the Company, service installations shall be made in accordance with the Company's "Electric Service Installation Rules," copies of which may be obtained by calling, e-mailing or writing the Company's business office. In addition, the Rules may be accessed at www.duquesnelight.com. (C)

6.1 SERVICE POINT The Service Point for the customer's service installation shall depend on the customer's type of service. The Service Point shall generally be designated as follows: (C)

Type of Service	Service Point
Service voltage greater than 600V	Metering terminals, or for transformed service, secondary transformer terminals
Overhead service at voltage less than 600V	Service drop
Underground service at voltage less than 600V	For underground service from overhead secondary lines: the service lateral connection to Company pole. For underground service from underground spot networks: the network protector spade(s). For underground service from street secondary underground networks: the collector bus. For three-phase transformed underground service: the secondary transformer terminal. In Underground Residential Developments covered by Rule No. 13.2: the meter base. For other underground service from underground secondary lines: the terminal box.
Any service via lines supported by a customer-owned pole or structure	Point of service line connection to the first customer-owned pole or structure to which Company facilities connect

The Company reserves the right to designate an alternative Service Point, at its sole discretion, for customers with atypical or specialized service configurations, or customers participating in the Company's EV ChargeUp pilot program for electric vehicle charging stations.

The Company shall not be required to install or maintain any conductors, meter base, equipment or apparatus except meter and meter accessories, as applicable, beyond the Service Point.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued) (C)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS

A. Definitions

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

(1) **Contractor cost** - The amount paid to a contractor for work performed on a line extension.

(2) **Direct labor cost** - The pay and expenses of public utility employees directly attributable to work performed on line extensions, but does not include construction overheads or payroll taxes, workers' compensation expenses, or similar expenses.

(3) **Direct material cost** - The purchase price of materials used for a line extension, but does not include the related stores expenses. In computing direct material costs, proper allowance should be made for unused materials recovered from temporary structures, and discounts allowed and realized in the purchase of materials.

(4) **Total construction cost** - The contractor cost, direct labor cost, direct material cost, stores expense, construction overheads, payroll taxes, workers' compensation expenses, or similar expenses.

(5) **Current Year** - For purposes of calculating a revenue guarantee, current year shall be each consecutive period of twelve (12) calendar months following the date permanent electric delivery service was first provided to a customer.

(6) **Income Tax** - Federal and State tax relating to the tax liability of contributions in aid-of-construction ("CIAC").

B. Overhead Areas

(1) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all single-phase overhead supply lines operating at 23,000 volts or less to approximately 100 feet within the customer's property line without a guarantee of revenue. (C)

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

B. Overhead Areas - (Continued)

(2) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all three-phase overhead supply lines, operating at 23,000 volts or less, which are usable as a part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer over a period of five years which is sufficient to recover the actual total construction cost of the three-phase overhead line extension, less the estimated total construction cost for an equivalent single-phase overhead line extension. In the event that a revenue guarantee is not sufficient to recover the estimated total cost of the construction, or if the Company determines that the extension is speculative, or the customer represents a credit risk, the Company may require an up-front contribution in aid of construction (CIAC) from the customer to recover the total cost of construction. A customer may choose the option to make a CIAC rather than utilize a revenue guarantee. The Company will consider financing alternatives, such as a letter of credit or other payment arrangements, in lieu of a CIAC when appropriate. Any additional CIAC payment required will include the related income tax. (C)

C. Underground Areas

(1) In areas where the existing supply lines are underground outside the limits of a residential development covered by Tariff Rule 13.2, the Company will construct and maintain extensions of all single-phase underground supply lines operating at 23,000 volts or less which are usable as part of its general supply system without a guarantee of revenue. When the single-phase supply line extension is to supply electricity exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer, over a period of five years which is sufficient to recover the actual total contractor cost, direct labor cost and direct material cost for the full length of the single-phase underground line extension, less the estimated total contractor cost, direct labor cost, and direct material cost for an equivalent single-phase overhead line extension. In the event that a revenue guarantee is not sufficient to recover the estimated total cost of the construction, or if the Company determines that the extension is speculative, or the customer represents a credit risk, the Company may require an up-front contribution in

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

C. Underground Areas - (Continued)

aid of construction (CIAC) from the customer to recover the total cost of construction. A customer may choose the option to make a CIAC rather than utilize a revenue guarantee. The Company will consider financing alternatives, such as a letter of credit or other payment arrangements, in lieu of a CIAC when appropriate. Any additional CIAC payment required will include the related income tax.

(2) In areas where the existing supply lines are underground outside of the limits of a residential development covered by Tariff Rule 13.2, the Company will construct and maintain extensions of all three-phase underground supply lines operating at 23,000 volts or less which are usable as part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer over a period of five years which is sufficient to recover the actual total construction cost of the three-phase underground line extension, less the estimated total construction cost for an equivalent single-phase overhead line extension. In the event that a revenue guarantee is not sufficient to recover the estimated total cost of the construction, or if the Company determines that the extension is speculative, or the customer represents a credit risk, the Company may require an up-front contribution in aid of construction (CIAC) from the customer to recover the total cost of construction. A customer may choose the option to make a CIAC rather than utilize a revenue guarantee. The Company will consider financing alternatives, such as a letter of credit or other payment arrangements, in lieu of a CIAC when appropriate. Any additional CIAC payment required will include the related income tax.

(C)

D. Rights-of-Way

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

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

E. Revenue Guarantees

The revenue guarantee amount shall be the estimated combined cost of (i) the line extension (C)
and (ii) other new Company facilities necessary to serve the customer. The annual revenue (C)
guarantee amount shall be the revenue guarantee amount, divided by the number of years in the guarantee period. The annual revenue guarantee amount will be reviewed yearly and will be adjusted to the minimum charges as provided in the applicable rate schedule on the following basis:

(1) When the total of the monthly Company delivery charges at the end of the current year is less than the annual revenue guarantee amount, a payment equal to the difference plus the related income tax where applicable shall be immediately due and payable.

(2) When the total of the monthly Company delivery charges within the number of years in the guarantee period equals or exceeds the revenue guarantee amount, no further payments
toward the revenue guarantee amount are required. Any prior payments in excess of the (C)
revenue guarantee amount, except for otherwise-applicable charges for electric service, (C)
will be refunded with accrued interest.

(3) If an additional customer is served from the line extension, the revenue guarantee amount will be reduced to the cost of the line extension which is used exclusively to serve the single customer. If the cost of the line extension to serve the new customer would increase the revenue guarantee amount for an existing customer, the extension shall be considered as a new line extension.

(4) In the event the customer discontinues or cancels service before the end of the guarantee period, the balance of the revenue guarantee amount plus the related income tax where applicable shall be immediately due and payable.

F. Contributions in Aid of Construction

The Contribution in Aid of Construction (CIAC) will be refunded to the customer over the five-year revenue guarantee period to the extent that the revenue from the customer satisfies the revenue guarantee.

(1) When the total of the monthly Company delivery charges at the end of the current year is greater than or equal to one-fifth of the CIAC, a refund of one-fifth of the CIAC will be made to the customer.

(2) When the total of the monthly Company delivery charges at the end of the current year is less than one-fifth of the CIAC, a refund of one-fifth of the CIAC less the revenue shortfall will be made to the customer.

(3) At the end of the five-year revenue guarantee period, a final reconciliation of delivery charges during the period will be made against the CIAC. If the total delivery charges paid exceed or equal the original CIAC, any remaining CIAC will be returned to the customer. If the total delivery charges paid are less than the original CIAC, the remaining CIAC will be retained by the Company.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

8. **NONSTANDARD SERVICE** The Company reserves the right to require a customer or applicant for service to pay the cost, including the related income tax, of any special installation necessary to meet the unusual requirements of the customer or applicant for service, including, but not limited to: (C)

(1) service at other than standard voltages, (C)

(2) service for intermittent, unbalanced or fluctuating loads, which, in the Company's sole judgement, would not generate sufficient revenue to recover the installation costs of the required facilities, (C)

(3) service for loads that will be continuous but that will generate minimal usage, and which, in the Company's sole judgement, would not generate sufficient revenue to recover the installation costs of the required facilities, (C)

(4) service for loads that will require provision of closer voltage regulation than required by standard service, (C)

(5) redundant service requested by the customer and not required by the Company, and (C)

(6) service routings or configurations that deviate from the Company's standard construction standards described in the Company's "Electric Service Installation Rules," or that would otherwise necessitate significant construction of new Company facilities. (C)

The customer or applicant shall pay all costs to the Company of performing environmental assessments, including, but not limited to, the cost of consultants utilized by the Company, the cost of removal and disposal of contamination, waste or hazardous materials or dealing with other adverse environmental conditions associated with either the initial installation, modification, repair, maintenance or removal of service facilities. (C)

The Company may decline to provide Nonstandard Service where, in the Company's sole judgment, it would not be commercially, operationally, and/or technically reasonable to provide such service. (C)

9. **RELOCATIONS OF FACILITIES**

A. **Pole Removal or Relocation for Residential Customers**

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

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

(1) Contractor costs - Amount paid by the utility to a contractor for work performed on a pole removal or relocation.

(C)

RULES AND REGULATIONS - (Continued) **(C)**

INSTALLATION OF SERVICE - (Continued)

9. RELOCATIONS OF FACILITIES – (Continued)

A. Pole Removal or Relocation for Residential Customers – (Continued)

(2) **Direct labor costs** - Includes pay and expenses of public utility employees directly attributable to work performed on pole removals or relocations. Excludes payroll taxes, workmen's compensation, similar items of expense and construction overhead costs.

(3) **Direct materials costs** - Includes the purchase price of materials used in performing a pole removal or relocation and excludes the related stores expenses. Proper allowance shall be made for unused materials, and materials recovered from temporary structures, and for discounts allowed and realized in purchase of materials.

(4) **Income tax** - Federal and State tax relating to the tax liability of contributions in aid-of-construction.

B. Other Company Facilities for all Customers

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

RULES AND REGULATIONS - (Continued)

MEASUREMENT AND USE OF SERVICE - (Continued)

14.2 CUSTOMER REQUEST FOR SPECIAL METERING – (Continued)

The Company has adopted a program that provides all customers with meters to provide data for normal monthly billing services. In the event that a residential or small commercial customer, or an EGS on behalf of a residential or small commercial customer, requests an upgrade to an Alpha Powerplus meter, which the Company provides for large commercial and industrial customers, installation of that meter will be provided at a cost of $586.00, plus additional costs for the appropriate communication/system infrastructure. These net incremental charges, as set forth in the Company's Advance Meter Catalog, may be paid to the Company by either the customer or the EGS, or jointly by the customer and the EGS pursuant to a mutual agreement.

(C)
(C)

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

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

16. USE OF SERVICE BY CUSTOMER The customer shall use the electric service only at the premise where service is established; and after electric service has been established, shall notify the Company of any change in connected load, demand, or other conditions of use. The customer shall notify the Company of other on site sources of electric generation or electricity concurrently produced as a by-product of another process or electricity produced utilizing renewable resources. Customers who own and operate electric generation equipment shall conform with the Company's "Electric Service Installation Rules," copies of which may be obtained by calling, e-mailing or writing the Company's business office or at www.duquesnelight.com. For customers who own and operate electric generation, the provisions of Rider No. 16 - Service to Non-Utility Generating Facilities and Rider No. 21 - Net Metering Service may also apply.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

MEASUREMENT AND USE OF SERVICE - (Continued)

18. REDISTRIBUTION All electric energy shall be consumed by the customer to whom the Company supplies and delivers such energy, except that (1) the customer owning and operating a separate office building, and (2) any other customer who, upon showing that special circumstances exist, obtains the written consent of the Company may redistribute electric energy to tenants of such customer, but only if such tenants are not required to make a specific payment for such energy. (C)

This Rule shall not affect any practice undertaken prior to June 1, 1965. See Rule No. 41 for special requirements for residential dwelling units in a building.

18.1 ELECTRIC VEHICLE CHARGING For purposes of third party-owned electric vehicle charging stations, charging the electric vehicle shall not be considered redistribution as defined in Rule No. 18 - Redistribution. Electric vehicles are defined as any vehicle licensed to operate on public roadways that are propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles. Electric vehicle charging stations shall be made in accordance with the Company's "Electric Service Installation Rules," a copy of which may be found at www.duquesnelight.com. The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit as required by Company rules. The Company shall not be liable for any damages associated with operation of the charging station. For stations dedicated solely for the purpose of charging electric vehicles wherein a third party owns the charger and allows an electric vehicle owner to use their facility to charge an electric vehicle, the owner of the charging facility shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company. The third party owner of the station shall be responsible for all applicable Tariff rates, fees and charges. For such installations, the electric vehicle owner shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

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

BILLS AND NET PAYMENT PERIODS

20. BILLING The Company will render a bill monthly for electric service.

20.1 BILLING OPTIONS Customers who elect to purchase their electricity from an Electric Generation Supplier ("EGS") may choose: (1) Consolidated Billing and receive a single bill from the Company that includes Company charges and EGS charges; or (2) Separate Billing and receive one bill from the Company for Company charges and a second bill from the EGS for EGS charges. The customer's billing option will be communicated to the Company by the EGS, in accordance with the provisions contained in the Company's Supplier Tariff.

20.2 SUMMARY BILLING The Company may, at its discretion and upon customer request, provide Summary Bills in lieu of individual bills to qualifying customers. Summary Bills shall include an abridged summary of electric service usage and charges associated with each meter location. The Company may remove a customer from Summary Billing at its option or at the customer's request. (C)

For the purpose of determining whether to provide Summary Billing, the Company may consider, among other factors, whether the read and due dates of the multiple meter locations allow for Summary Billing without adversely affecting the timely payment of bills, and whether Summary Billing would have an adverse financial impact on the Company.

(C) – Indicates Change

RULES AND REGULATIONS – (Continued)

BILLS AND NET PAYMENT PERIODS – (Continued)

20.3 BILLS Bills for electric service are due and payable upon presentation and may be paid with a check or money order and placed in the payment drop box located at the Company's business office, by any of the means listed under the "Billing and Payment Conveniences" as described on Page 2 of the customer's bill or to any of its collecting agencies during the regular office hours of such agencies. For customers who select an EGS and who select the Separate Billing Option, payment of the bill from the EGS is due to the EGS per the EGS terms and conditions. When the meter readings are taken at other than monthly intervals or when the elapsed time between meter readings is substantially greater or less than one month, the rate values applicable to monthly delivery periods will be adjusted. (C)

20.4 BUDGET PAYMENT PLAN FOR RESIDENTIAL CUSTOMERS The Budget Payment Plan provides residential customers the option of paying a budget amount each month based on their average monthly charges over a rolling twelve (12) month period. The Budget Payment Plan is available upon request for residential customers not in arrears for payment of service. The Budget Payment Plan will average utility service charges on an estimated annual basis by account and will be reviewed periodically for adjustment. When the Company provides Consolidated EDC Rate Ready Billing, the EGS's charges for conventionally-priced supply service will be included in the customer's Budget Payment Plan. When the Company provides Consolidated EDC Bill Ready Billing, the EGS's charges for conventionally-priced supply service will be included in the customer's Budget Payment Plan at the EGS's election. If the customer elects a dynamically-priced supply product (e.g., time-of-use pricing, real-time pricing, critical-peak pricing, peak-time rebate pricing, etc.) from the EGS, charges will not be included in the customer's Budget Payment Plan unless the customer receives prior authorization from the EGS and is on Consolidated EDC Rate Ready Billing. If a customer fails to pay an outstanding bill by the required due date, the Company may, in its sole discretion, terminate that customer's enrollment in the Budget Payment Plan and the difference owed the Company shall be immediately due. For customers enrolled in the Budget Payment Plan, the Company will reconcile the difference between the actual amount due and the budget amount paid to date in the twelfth month from the date of the Customer's enrollment in the Plan. Reconciliation amounts will be handled in accordance with Pennsylvania Public Utility Commission regulations including 52 Pa. Code § 56.12. (C) (C)

21. NET PAYMENT Payments placed in the payment drop box at the Company's business office or payments made direct to the Company's collecting agencies will be accepted by the Company in the amount billed as per the terms stated at each respective location. Payments made by mail may be accepted in the amount billed by the Company, at its option, if the payment is received within five (5) days after the due date. A Late Payment Charge will be added to Company charges for failure to make payment of the bill in accord with the above.

21.1 PAYMENT OF BILLS FOR RESIDENTIAL SERVICE The Company will designate a due date on its bill which shall be a business day no less than 20 days from the date of transmittal of the bill. The Company may accommodate changes to due dates for residential customers upon written customer request and when a demonstrated financial burden for the current due date exists for ratepayers receiving Social Security or equivalent monthly checks.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

BILLS AND NET PAYMENT PERIODS – (Continued)

21.2 PARTIAL PAYMENT OF BILLS For customers who submit payments which are insufficient to cover all of the charges billed by the Company, including EGS charges for those customers who have selected consolidated billing, the Company will apply the payment based upon their outstanding balance, if any, and their current bill, as follows: (1) past due deposit; (2) past-due distribution charges; (3) past-due transmission and supply charges; (4) past due non-basic charges; (5) current deposit; (6) current distribution charges; (7) current transmission and supply charges; and (8) current non-basic charges.

21.3 RETURNED PAYMENT CHARGE If a payment on a Customer's account is returned to the Company unpaid by the Customer's financial institution or another entity responsible for processing payment and cannot be reprocessed by the Company for payment, a $20.00 charge will be added to the Customer's account. If such an occurrence happens a second time within any twelve (12) month period, personal checks and electronic checks will not be accepted by the Company to make the current payment and future payments on the Customer's account until a timely payment history is established by the Customer as defined by 52 Pa. Code § 56.53(b).

COMPANY PROPERTY ON CUSTOMER'S PREMISES

22. ACCESS TO PREMISES Company representatives, who are properly identified, shall have full and free access to the customer's premises at all reasonable times for the purpose of reading Company meters, for inspection and repairs, for removal of Company property, or for any other purpose incident to the service. The (C)
Company shall have the right to access customer owned facilities and equipment at all hours for the purposes of responding to an emergency, restoring electric service, rendering the electric facilities safe and reliable, or for the purpose of reducing the likelihood of damage to the Company's facilities or equipment. The customer should immediately communicate with the Company in case of any question as to the authority or credentials of Company representatives. A customer's failure to provide access may be grounds for service termination (C)
pursuant to Rule No. 33 herein.

22.1. VEGETATION MANAGEMENT AND RIGHT-OF-WAY The customer, applicant, or property owner shall (C)
provide, without charge to the Company, right-of-way and access across property owned or controlled by customer/applicant/property owner, and locations and housings which are suitable, in the opinion of Company, for the construction, reconstruction, maintenance or operation of Company facilities that serve the customer/applicant/property owner. Suitable right-of-way includes, but is not limited to, the right of ingress and egress to and from the electric facilities for any of the purposes aforesaid; and also the right to prune, cut or remove trees, underbrush and other obstructions which, in the judgment of Company, may at any time interfere with the construction, reconstruction, maintenance or operation of the electric facilities, and in connection therewith, the right to treat with herbicides approved for the removal and control of trees, brush and undergrowth. The Company shall also have all of the aforesaid rights related to its provision of underground service to a customer/applicant/property owner, even if the Company does not require the customer/applicant/property owner to execute a formal right-of-way document.

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

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

(C)

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

(C)

DISCONTINUANCE, CURTAILMENT OR INTERRUPTION OF ELECTRIC SERVICE

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

26. ARREARS The Company upon reasonable notice may terminate electric service and remove its equipment from the premises for nonpayment of undisputed Company service charges, Company charges as the default service charges or EGS receivables purchased by the Company up to the amount that the customer would have paid under Default Service rates during the non-payment period, pursuant to Duquesne's Electric Generation Supplier Coordination Tariff Rule No. 12.1.7. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

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

26.1 COLLECTION REVIEW The Company shall review accounts for collection purposes as reasonable and appropriate. The Company may pursue all lawful means of collection of accounts as permitted by applicable law.

27. CONTRACTS OR APPLICATIONS Where electric service has been established without the customer first having executed a written contract or application, the Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer refuses or neglects to execute a written contract or application when requested so to do by the Company. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

27.1 DEATH OF A RESIDENTIAL CUSTOMER A residential customer shall notify the Company upon the death of any other customer listed on the same residential service account. The Company may request and require proof of death prior to removing the deceased customer from the account. The Company may require evidence of the deceased customer's estate (such as a Decree of Probate) prior to listing the account in the name of the deceased customer's estate. (C)

Where a residential service account is listed solely in the name of a deceased customer, and service is not established in the name of the deceased customer's estate or a different customer, the Company may discontinue the service consistent with 66 Pa. C.S. § 1503.

28. DEPOSITS The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer refuses or neglects to post a cash deposit based on Company charges when requested to do so by the Company, as provided under Rule No. 5. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

29. UNDERGROUND SERVICE The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice when the customer refuses or neglects to provide at his own expense the necessary facilities for receiving underground service, as provided under Rule No. 13.1. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

30. HAZARDOUS AND IMPROPER CONDITIONS The Company may terminate electric service and remove its equipment from the premises if in the judgment of the Company the customer's installation has become dangerous or defective, or if the Company has received a notice from the proper authorities that the customer's equipment is dangerous or defective, or if the customer's equipment or use thereof injuriously affects the equipment of the Company or the Company's service to other customers. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

31. MISREPRESENTATIONS The Company reserves the right to terminate electric service and remove its equipment from the premises in case the customer has made misrepresentations to the Company with respect to the customer's identity or the use of the electric service. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

32. REDISTRIBUTION The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer redistributes the electric service contrary to the provisions set forth in this tariff. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

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

33. **INACCESSIBILITY** The Company may terminate electric service and remove its equipment from the premises upon reasonable notice in case meter readers or other authorized representatives of the Company cannot gain admittance or are refused admittance to the premises for the purposes of reading Company meters, (C)
inspection and repairs, removal of Company property, responding to an emergency, restoring electric service, (C)
rendering the electric facilities safe and reliable, or for any other purpose incident to the service or in case the (C)
customer interferes with Company representatives in the performance of their duties. When a residential (C)
customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

34. **TAMPERING** The Company may terminate electric service and remove its equipment from the premises in case the Company's property on the premises has been interfered with, or in case evidence is found that the service wires, meters, switch-box or other appurtenances on the premises have been tampered with. When a residential customer or residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

35. **REPAIRS AND LOSSES** The Company may terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer shall neglect or refuse to reimburse the Company for repairs to or loss of the Company's property on the premises when such repairs are necessitated, or loss occasioned, by negligence on the part of the customer. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

36. **WRITS AND LEVIES** The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case a Writ of Execution is issued against the customer, or in case the premises at which service is supplied is levied upon, or in case of assignment or act of bankruptcy on the part of the customer. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

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

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

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

(C) – Indicates Change

GENERAL PROVISIONS- (Continued)

45.3 SWITCHING BETWEEN LOCATIONS - (Continued)

1. At least one (1) business day notice to the Company is required to effectuate the move. Requests to start service on the same day as the request will not be honored nor will the Company allow customers to back-date service.

2. The move will not be allowed for any overlapping service or gaps in service lasting more than three (3) days.

3. An EGS must currently be providing service on the customer's account and any termination of EGS service prior to the customer's move will preclude continued service from the same EGS at the new location by the Company.

If the above criteria have been met, the Company will advise the customer that their EGS supply service will seamlessly move to their new location and the Company will send a new move transaction to the EGS.

The move may be terminated or voided after the move transaction is complete under certain circumstances, including where the customer: 1.) voids or terminates the new account prior to the service start date; 2.) requests to change the service start date on the new account to a date occurring in the past; or 3.) enrolls with a new EGS on the current account before the connection to the new account occurs. In these instances, the Company will send a drop notification to the EGS.

45.4 STARTING SERVICE WITH AN EGS Customers starting new service with the Company will be permitted to begin supply service with an EGS on their start date subject to meeting the eligibility requirements in Rule No. 45.3 and conditions set forth in this Rule.

The Company will process EGS service to a new customer provided that the customer has met all of the following criteria:

1. the customer has provided notice to the Company at least three (3) business days prior to the start date for new service;

2. the customer will not be permitted to back-date service;

3. the customer has satisfied all requirements to start service at the new location; and

4. the customer has contacted the EGS to initiate supply service.

46. PROVISION OF LOAD DATA The Company will provide to a customer or its authorized representative historical data in accordance with all current regulatory requirements of direct access up to five (5) requests for **(C)**
the same account in a calendar year at no charge. All subsequent requests by the customer, and all requests for **(C)**
historical data by the EGSs or other customer authorized consultant will be provided in accordance with the Supplier Tariff.

47. TAX INDEMNIFICATION If Duquesne Light Company becomes liable under Section 2806(g) or 2809(c) of the Public Utility Code, Pa. C.S. §§ 2806(g) and 2809(f), for Pennsylvania state taxes not paid by an Electric Generation Supplier (EGS), the non-compliant EGS shall indemnify Duquesne for the amount of additional state tax liability imposed upon Duquesne by the Pennsylvania Department of Revenue due to the failure of the EGS to pay or remit to the Commonwealth the tax imposed on its gross receipts under Section 1101 of the Tax Report Code of 1971 or Chapter 28 of Title 66.

(C) – Indicates Change

RATE RS - RESIDENTIAL SERVICE

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, and general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge .... $16.25 **(I)**

Energy Charge .... 6.1147 per kilowatt hour **(I)**

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

(I) – Indicates Increase

RATE RH - RESIDENTIAL SERVICE HEATING

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and as the sole primary method of space heating except that the space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge .... $16.25 **(I)**

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge .... 4.6451 cents per kilowatt hour **(I)**

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... 6.1147 cents per kilowatt hour **(I)**

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE RA - RESIDENTIAL SERVICE ADD-ON HEAT PUMP

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and an add-on heat pump for space heating. Other energy sources may be used to supplement the add-on heat pump provided that the supplemental energy source is thermostatically controlled to operate only when the outdoor temperature falls to at least 40^{O} F and the add-on heat pump cannot provide the total heating requirements.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge .... $16.25 **(I)**

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge .... 1.5485 cents per kilowatt hour **(I)**

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... 6.1147 cents per kilowatt hour **(I)**

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM

AVAILABILITY

Available for all the standard electric service taken on a small or medium general service customer's premises for which a residential rate is not available.

MONTHLY RATE FOR NON-DEMAND CUSTOMERS (C)

DISTRIBUTION CHARGES — RATE GS (C)

Customer Charge .... $16.25 (I)

Energy Charge — All kWh .... 7.2821 cents per kilowatt-hour (I)

MONTHLY RATE FOR DEMAND CUSTOMERS (C)

DISTRIBUTION CHARGES — RATE GM < 25 kW (C)

Customer Charge .... $56.00 (I)

Energy Charge — All kWh .... 1.5123 cents per kilowatt-hour (I)

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... $7.09 per kilowatt (I)

DISTRIBUTION CHARGES — RATE GM ≥ 25 kW (C)

Customer Charge .... $67.00 (I)

Energy Charge — All kWh .... 0.9381 cents per kilowatt-hour (I)

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... $7.09 per kilowatt (I)

(C) – Indicates Change (I) – Indicates Increase

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM - (Continued)

MONTHLY RATE FOR NON-DEMAND AND DEMAND CUSTOMERS (C)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for customers will be updated through competitive requests for proposal described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to non-demand customers, customers with monthly demand less than 25 kW and customers with monthly demand equal to or greater than 25 kW shall be as described in Rider No. 8 and for the effective periods defined in Rider No. 8. (C) (C)

(C)

A new customer or a customer with limited or no historical data shall be eligible for and assigned to the applicable rate based on Duquesne Light's estimate of the customer's monthly usage and/or peak monthly demand for the next twelve (12) month period. In no instance shall a customer be eligible for more than one of Rate GS, Rate GM < 25kW or Rate GM ≥ 25 kW at a time. (C)

Rate GS Customers A customer's assignment to Rate GS is for a twelve-month period. The Company shall review the customer's rate upon the expiration of such twelve-month period and shall assign the customer to the applicable rate based on a rolling twelve-month average of the customer's usage and billing demand as follows: (C)

- If the customer's average monthly usage is 1,000 kWh or less, and the customer's average monthly billing demand is 5 kW or less, the customer shall be assigned to Rate GS. (C)
- If the customer's average monthly usage is greater than 1,000 kWh, or the customer's average monthly billing demand is greater than 5 kW, the customer shall be assigned to the Rate GM < 25kW or Rate GM ≥ 25 kW, as applicable, effective with the customer's next billing cycle. (C)

Rate GM < 25 kW and Rate GM ≥ 25 kW Customers A customer's assignment to Rate GM < 25kW or to Rate GM ≥ 25 kW is for a period of twelve (12) months or until the customer's next January billing, whichever is longer. Each October, Duquesne Light shall evaluate the customer's average monthly usage and billing demand for the past twelve (12) most recent months, for purposes of determining the customer's rate for the following year. (C)

- If the customer's average monthly usage was 1,000 kWh or less and the customer's average monthly billing demand was 5 kW or less, the customer shall be assigned to Rate GS effective with the customer's next January billing. (C)
- If the customer's average monthly billing demand was greater than 5 kW but less than 25 kW, the customer shall be assigned to Rate GM < 25 kW effective with the customer's next January billing. (C)
- If the customer's average monthly billing demand was 25 kW or greater, the customer shall be assigned to Rate GM ≥ 25 kW effective with the customer's next January billing. (C)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(C) – Indicates Change

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM - (Continued)

MONTHLY RATE FOR NON-DEMAND AND DEMAND CUSTOMERS - (Continued) (C)

ELECTRIC CHARGES – (Continued) (C)

Customers who elect to purchase their electric energy requirements from an EGS will be charged the Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity at the above Distribution and Supply Charges and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

MINIMUM CHARGE

The Minimum Charge shall be the sum of the Customer Distribution Charge plus a Demand Charge based on 50% of the current month Billing Demand or 30% of the highest Billing Demand, during the preceding eleven months, whichever is greater, plus the current billing period charges for Company supplied transmission and supply service, if any. The Demand Charge shall be determined using the Distribution Charge only, but shall not be less than the Customer Distribution Charge.

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

DETERMINATION OF DEMAND

The demand will be measured where a customer's monthly use exceeds 1,000 kilowatt-hours or where the demand is known to exceed 5 kilowatts. Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen-minute period of greatest kilowatt-hour use during the billing period. Individual demands which exceed 30 kilowatts will be adjusted for power factor by multiplying by

$$\left\{0.8 + \left[0.6 \frac{\text{Reactive Kilovolt - ampere hours}}{\text{Kilowatt - hours}}\right]\right\},$$

where such multiplier will be not less than 1.00 nor more than 2.00. The Billing Demand will be the sum of the individual demands of each metered service, adjusted for power factor as defined above.

CONTRACT PROVISIONS

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

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see “Standard Contract Riders.”

(C) – Indicates Change

RATE GMH - GENERAL SERVICE MEDIUM HEATING

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE (C)

WINTER MONTHLY RATE — FOR THE BILLING MONTHS OF OCTOBER THROUGH MAY (C)

DISTRIBUTION CHARGES (C)

Customer Charge .... $56.00 (I)

Energy Charge — All kWh .... 3.1725 cents per kilowatt-hour (I)

SUMMER MONTHLY RATE — FOR THE BILLING MONTHS OF JUNE THROUGH SEPTEMBER (C)

DISTRIBUTION CHARGES (C)

Customer Charge .... $56.00 (I)

Energy Charge — All kWh .... 1.5123 cents per kilowatt-hour (I)

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... $7.09 per kilowatt (I)

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

(C)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for customers will be updated through competitive requests for proposal described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to non-demand customers, customers (C)
with monthly demand less than 25 kW and customers with monthly demand equal to or greater than 25 kW shall (C)
be as described in Rider No. 8 and for the effective periods defined in Rider No. 8.

For purposes of determining the monthly rate for demand customers, Duquesne Light shall evaluate the (C)
customer's twelve (12) most recent months of monthly billing demand for that customer available in October of the (C)
preceding year. If the customer's average monthly billing demand is less than 25 kW in the twelve (12) months, (C)
then that customer shall be charged the monthly rate for demand customers less than 25 kW for the next calendar (C)
year and automatically assigned to that rate effective with their January billing. If the customer's average monthly (C)
demand is 25 kW or greater in the twelve (12) month period, then that customer shall be charged the monthly rate (C)
for demand customers equal to or greater than 25 kW for the next calendar year and automatically assigned to (C)
that rate as their default service rate effective with their January billing. In no instance shall a customer be eligible for more than one default service offering at a time. A new customer or a customer with limited or no historical data shall be eligible for and assigned to the applicable rate based on Duquesne Light's estimate of the customer's average monthly billing demand for the next twelve (12) month period. (C)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(C) – Indicates Change

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC CHARGES – (Continued)

Customers who elect to purchase their electric energy requirements from an EGS will be charged the Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity at the above Distribution and Supply Charges and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

MINIMUM CHARGE

For the months of October through May, the Minimum Charge shall be the Customer Distribution Charge for the first kilowatt, plus a Distribution Charge of $7.09 per kW, plus the current billing period charges for Company (I) supplied transmission and supply service, if any. The Minimum Charge shall not be less than the Customer Distribution Charge. For the months of June through September, the Minimum Charge shall be calculated in accordance with the Minimum Charge provisions in Rate GS/GM.

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

DETERMINATION OF DEMAND

The demand will be measured where a customer's monthly use exceeds 1,000 kilowatt-hours or where the demand is known to exceed 5 kilowatts. The demand will be the sum of individual demands of each metered standard service. Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen-minute period of greatest kilowatt-hour use during the billing period. For the months of June through September, demand will be determined as defined in Rate GS/GM.

(I) – Indicates Increase

RATE GL - GENERAL SERVICE LARGE

AVAILABILITY

Available for all the standard electric service taken on a customer's premises where the demand is not less than 300 kilowatts.

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

DEMAND CHARGES

First 300 kilowatts or less of Demand	$3,000.00	(I)
Additional kilowatts of Demand	$9.66 per kW	(I)

ELECTRIC CHARGES

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE GLH - GENERAL SERVICE LARGE HEATING

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE

CUSTOMER CHARGE

Customer Distribution Charge .... $67.00 (I)

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

For the Billing Months of October through May:

ENERGY CHARGES

All kilowatt-hours 2.4828 cents per kWh (I)

For the Billing Months of June through September:

Rate GL shall apply.

RATE GLH - GENERAL SERVICE LARGE HEATING - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC CHARGES

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

MINIMUM CHARGE

For the months of October through May, the Minimum Charge shall be the Customer Distribution Charge for the first kilowatt plus a Distribution Charge of $9.66 per kW and the charges for Company supplied transmission and (I) supply, if any. For Company supplied transmission and supply, the transmission charges shall be calculated as set forth in Appendix A and the supply charges shall be calculated as set forth under Rider No. 9. The Minimum Charge shall not be less than the Customer Distribution Charge. For the months of June through September, the Minimum Charge shall be calculated in accordance with the Minimum Charge provisions contained in Rate GL.

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

(C) – Indicates Change (I) – Indicates Increase

RATE L - LARGE POWER SERVICE

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

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

DEMAND CHARGES

Service Voltage Less than 138 kV:

First 5,000 kilowatts or less of Demand	$48,500.00	(I)
Additional kilowatts of Demand	$11.50 per kW	(I)

(C)

ELECTRIC CHARGES

The Company will provide and charge for Transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE L - LARGE POWER SERVICE - (Continued)

VOLTAGE CONTROL PROVISION

The customer shall be required to operate its 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. (C)

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%.

(C) – Indicates Change

RATE HVPS - HIGH VOLTAGE POWER SERVICE

AVAILABILITY

Available to customers with Contract On-Peak Demands greater than 5,000 kilowatts where service is supplied at 69,000 volts or higher. (C)

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

FIXED MONTHLY CHARGE

Up to and Including 50,000 kW Billing Demand	$7,482.78	(D)
50,001 kW to 100,000 kW Billing Demand	$11,688.61	(D)
Greater than 100,000 kW Billing Demand	$16,576.26	(D)

ELECTRIC CHARGES

The Company will provide and charge for Transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE HVPS - HIGH VOLTAGE POWER SERVICE - (Continued)

MONTHLY RATE - (Continued)

MINIMUM CHARGE

The Minimum Charge shall be the Demand Charge based on 70% of the Contract On-Peak Demand for transmission and distribution and the Demand Charge as calculated under Rider No. 9 for Company supplied supply. The Demand Charge shall be determined using the Distribution Charge, and the Transmission and Supply Charges associated with Company supplied transmission and supply, if any, but in total not less than the demand charges associated with the first 5,000 kWs or less of demand. (C)

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

DETERMINATION OF DEMAND FOR DISTRIBUTION

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 5,000 kilowatts, whichever is the greater. (C)

ON-PEAK AND OFF-PEAK CONTRACT DEMAND

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

(C) – Indicates Change

RATE HVPS - HIGH VOLTAGE POWER SERVICE - (Continued)

CONTRACT PROVISION – (Continued)

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. (C)

VOLTAGE CONTROL PROVISION

The customer shall be required to operate its 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. (C)

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%.

FACILITIES CHARGE

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

(C) – Indicates Change

RATE AL - ARCHITECTURAL LIGHTING SERVICE

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

DISTRIBUTION CHARGES

Customer Charge .... $8.00 (I)

Demand Charge .... $1.59 per kilowatt (I)

Energy Charge .... 0.2110 cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate AL – Architectural Lighting Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate AL customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(I) – Indicates Increase

RATE AL - ARCHITECTURAL LIGHTING SERVICE - (Continued)

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see "Standard Contract Riders."

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.

(C)

(C) – Indicates Change

RATE SE - STREET LIGHTING ENERGY

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

DISTRIBUTION CHARGE

Monthly charge per lamp.. $2.91 (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SE – Street Lighting Energy customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate SE customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(I) – Indicates Increase

RATE SM - STREET LIGHTING MUNICIPAL

AVAILABILITY

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

Mercury vapor street lighting is only available where served prior to January 30, 1983, and continuously thereafter at the same location. Beginning January 1, 2019, replacement of mercury vapor lamps, fixtures or luminaries, including brackets and ballasts, will not be available. In such cases, the customer must take service under one of the available lighting unit options listed below. (C) (C) (C)

A minimum of ten (10) LED lights per customer per individual order is required and must be installed in a contiguous location when replacing existing lighting. (C)

The Company shall not be required to install more than 3,000 LED lights annually. (C)

MONTHLY RATE

DISTRIBUTION CHARGE — Monthly Rate Per Unit (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment Distribution Charge per Unit	Customer Owned and Maintained Equipment Distribution Charge per Unit	(C)(C)(C)(C)
Mercury Vapor				
100	44	$12.69	$2.71	(I)(C)
175	74	$12.95	$2.71	(I)(C)
250	102	$13.20	$2.71	(I)(C)
400	161	$13.73	$2.71	(I)(C)
1,000	386	$15.79	$2.71	(I)(C)
Sodium Vapor				
70	29	$13.11	$2.71	(I)(C)
100	50	$13.21	$2.71	(I)(C)
150	71	$13.40	$2.71	(I)(C)
250	110	$13.75	$2.71	(I)(C)
400	170	$14.30	$2.71	(I)(C)
1,000	387	$16.44	$2.71	(I)(C)

(C) – Indicates Change (I) – Indicates Increase

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)

MONTHLY RATE – (Continued) (C)

DISTRIBUTION CHARGE — Monthly Rate Per Unit - (Continued) (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment Distribution Charge per Unit	Customer Owned and Maintained Equipment Distribution Charge per Unit	
Light-Emitting Diode (LED) — Cobra Head				(C)
45	16	$13.01	$2.71	
60	21	$13.52	$2.71	
95	34	$13.99	$2.71	
139	49	$15.08	$2.71	
219	77	$17.54	$2.71	
275	97	$19.24	$2.71	
Light-Emitting Diode (LED) — Colonial				(C)
48	17	$12.18	$2.71	
83	29	$12.18	$2.71	
Light-Emitting Diode (LED) — Contemporary				(C)
47	17	$14.19	$2.71	
62	22	$14.19	$2.71	

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SM – Street Lighting Municipal customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate SM customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(C)

RATE SM - STREET LIGHTING MUNICIPAL - (Continued) (C)

MONTHLY RATE – (Continued)

ELECTRIC CHARGES – (Continued) (C)

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

POLES

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 the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of $10.32 for each pole required. (I)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE (C)

A per unit monthly charge whenever the customer or an agent of the customer owns the entire street lighting system, including, but not limited to, the fixture, pole, circuit, controls, and all other related equipment on the load side of the Company's service point or when such facility is provided by a public agency and the customer and/or agent is obligated to operate and maintain such facility.

The street lighting system equipment must be approved by and installed in a manner acceptable to the Company and must be equipped with photocells or other such equipment that permit only dusk-to-dawn operation.

(C) – Indicates Change (I) – Indicates Increase

RATE SM - STREET LIGHTING MUNICIPAL - (Continued) (C)

MONTHLY RATE – (Continued)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE – (Continued) (C)

The customer/agent must provide the Company with a written inventory of all street lighting fixtures. This inventory shall include the location, type and wattage rating for each fixture. The customer/agent will update its inventory of lighting fixtures by informing the Company in writing of changes in type, rating, location, and quantity of lighting fixtures as such changes occur and billings will be adjusted accordingly.

The Company reserves the right to inspect the equipment at each location and make prospective adjustments in billing as indicated by such inspections. The Company shall be under no obligation to conduct such inspections for the purpose of determining accuracy of billing or otherwise. The Company's decision not to conduct such inspections shall not release the customer/agent from the obligation to provide to the Company, and to update, an accurate inventory of the types, ratings, and quantities of lighting equipment upon which billing is based.

As this service is a per unit monthly charge, the customer/agent agrees to pay amounts billed in accordance with the current inventory, regardless of whether any of the equipment was electrically operable during the period in question and regardless of the cause of any such equipment's failure to operate.

The contract period is as covered by any existing contract now in effect with the customer/agent. All new contracts shall be for a period of one year.

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.

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.

5. Non-standard installations. The Company may offer non-standard lighting units and installations in addition to those listed in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract, based on the incremental cost over that listed in the Monthly Rate Table. (C)

RATE SH - STREET LIGHTING HIGHWAY

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 Lıght 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

DISTRIBUTION CHARGE — Monthly Rate Per Unit (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment Distribution Charge per Unit	Customer Owned and Maintained Equipment Distribution Charge per Unit	
				(C)(C)(C)(C)
Sodium Vapor				
100	50	$12.54	$2.71	(I)(C)
150	71	$12.71	$2.71	(I)(C)
200	95	$12.89	$2.71	(I)(C)
400	170	$13.57	$2.71	(I)(C)
Light-Emitting Diode (LED) — Cobra Head				(C)
60	21	$13.52	$2.71	
95	34	$13.99	$2.71	
139	49	$15.08	$2.71	
219	77	$17.54	$2.71	

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

(C)

(C) – Indicates Change (I) – Indicates Increase

RATE SH - STREET LIGHTING HIGHWAY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC CHARGES (C)

The Supply Charges for Rate SH – Street Lighting Highway customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate SH customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE (C)

A per unit monthly charge whenever the customer or an agent of the customer owns the entire street lighting system, including, but not limited to, the fixture, pole, circuit, controls, and all other related equipment on the load side of the Company's service point or when such facility is provided by a public agency and the customer and/or agent is obligated to operate and maintain such facility.

The street lighting system equipment must be approved by and installed in a manner acceptable to the Company and must be equipped with photocells or other such equipment that permit only dusk-to-dawn operation.

(C) – Indicates Change

RATE SH - STREET LIGHTING HIGHWAY - (Continued)

MONTHLY RATE - (Continued)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE – (Continued) (C)

The customer/agent must provide the Company with a written inventory of all street lighting fixtures. This inventory shall include the location, type and wattage rating for each fixture. The customer/agent will update its inventory of lighting fixtures by informing the Company in writing of changes in type, rating, location, and quantity of lighting fixtures as such changes occur and billings will be adjusted accordingly.

The Company reserves the right to inspect the equipment at each location and make prospective adjustments in billing as indicated by such inspections. The Company shall be under no obligation to conduct such inspections for the purpose of determining accuracy of billing or otherwise. The Company's decision not to conduct such inspections shall not release the customer/agent from the obligation to provide to the Company, and to update, an accurate inventory of the types, ratings, and quantities of lighting equipment upon which billing is based.

As this service is a per unit monthly charge, the customer/agent agrees to pay amounts billed in accordance with the current inventory, regardless of whether any of the equipment was electrically operable during the period in question and regardless of the cause of any such equipment's failure to operate.

The contract period is as covered by any existing contract now in effect with the customer/agent. All new contracts shall be for a period of one year.

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 volts from a single point or multiple points of supply satisfactory to the Company. Fixtures operating at higher voltages will not be acceptable. (C)

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.

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.

(C)

(C) – Indicates Change

RATE SH - STREET LIGHTING HIGHWAY - (Continued) (C)

SPECIAL TERMS AND CONDITIONS - (Continued)

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.

9. Non-standard installations. The Company may offer non-standard lighting units and installations in addition to those listed in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract, based on the incremental cost over that listed in the Monthly Rate Table. (C)

TERM OF CONTRACT

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

(C) – Indicates Change

RATE UMS – UNMETERED SERVICE

AVAILABILITY

Available to customers using unmetered standard service at each point of connection for customer-owned and maintained equipment such as traffic signals, communication devices and billboard lighting.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge $10.00

Energy Charge .... 1.2822 cents per kilowatt hour (D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate UMS – Unmetered Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate UMS customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(D) – Indicates Decrease

RATE PAL - PRIVATE AREA LIGHTING

AVAILABILITY

Available for high pressure sodium lighting and flood lighting of residential, commercial and industrial private property installations including parking lots, for normal dusk to dawn operation of approximately 4,200 hours per year.

MONTHLY RATE

DISTRIBUTION CHARGE - Monthly Rate Per Unit (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment Distribution Charge per Unit	Customer Owned and Maintained Equipment Distribution Charge per Unit	(C)
High Pressure Sodium				
70	29	$13.11	$2.71	(I)(D)
100	50	$13.21	$2.71	(I)(D)
150	71	$13.40	$2.71	(I)(D)
250	110	$13.75	$2.71	(I)(D)
400	170	$14.30	$2.71	(I)(D)
Flood Lighting				
100	46	$13.11	$2.71	(I)(D)
250	100	$13.72	$2.71	(I)(D)
400	155	$14.33	$2.71	(I)(D)
Light-Emitting Diode (LED) — Cobra Head				(C)
45	16	$13.01	$2.71	
60	21	$13.52	$2.71	
95	34	$13.99	$2.71	
139	49	$15.08	$2.71	
219	77	$17.54	$2.71	
275	97	$19.24	$2.71	
Light-Emitting Diode (LED) — Colonial				(C)
48	17	$12.18	$2.71	
83	29	$12.18	$2.71	
Light-Emitting Diode (LED) — Contemporary				(C)
47	17	$14.19	$2.71	
62	22	$14.19	$2.71	
				(C)

(C) – Indicates Change (I) – Indicates Increase

RATE PAL - PRIVATE AREA LIGHTING - (Continued)

MONTHLY RATE - (Continued)

SUPPLY CHARGES (C)

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate PAL – Private Area Lighting customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate UMS customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8. (C)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS , the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

POLES

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.

(C) – Indicates Change

RATE PAL - PRIVATE AREA LIGHTING - (Continued)

MONTHLY RATE - (Continued)

POLES – (Continued)

Where the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of $10.32 for each pole required. (I)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE (C)

A per unit monthly charge whenever the customer or an agent of the customer owns the entire street lighting system, including, but not limited to, the fixture, pole, circuit, controls, and all other related equipment on the load side of the Company's service point or when such facility is provided by a public agency and the customer and/or agent is obligated to operate and maintain such facility.

The street lighting system equipment must be approved by and installed in a manner acceptable to the Company and must be equipped with photocells or other such equipment that permit only dusk-to-dawn operation.

The customer/agent must provide the Company with a written inventory of all street lighting fixtures. This inventory shall include the location, type and wattage rating for each fixture. The customer/agent will update its inventory of lighting fixtures by informing the Company in writing of changes in type, rating, location, and quantity of lighting fixtures as such changes occur and billings will be adjusted accordingly.

The Company reserves the right to inspect the equipment at each location and make prospective adjustments in billing as indicated by such inspections. The Company shall be under no obligation to conduct such inspections for the purpose of determining accuracy of billing or otherwise. The Company's decision not to conduct such inspections shall not release the customer/agent from the obligation to provide to the Company, and to update, an accurate inventory of the types, ratings, and quantities of lighting equipment upon which billing is based.

As this service is a per unit monthly charge, the customer/agent agrees to pay amounts billed in accordance with the current inventory, regardless of whether any of the equipment was electrically operable during the period in question and regardless of the cause of any such equipment's failure to operate.

The contract period is as covered by any existing contract now in effect with the customer/agent. All new contracts shall be for a period of one year.

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.

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.

(C)

(I) – Indicates Increase (C) – Indicates Change

RATE PAL - PRIVATE AREA LIGHTING - (Continued) (C)

SPECIAL TERMS AND CONDITIONS – (Continued)

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.

5. Non-standard installations. The Company may offer non-standard lighting units and installations in addition to those listed in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract, based on the incremental cost over that listed in the Monthly Rate Table. (C)

(C) – Indicates Change

STANDARD CONTRACT RIDERS – (Continued)

RIDER MATRIX

	RS	RH	RA	GS/GM	GMH	GL	GLH	L	HVPS	AL	SE	SM	SH	UMS	PAL	
Rider No. 1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Rider No. 2				X	X	X	X									
Rider No. 3				X	X	X	X	X								
Rider No. 4																(C)
Rider No. 5	X	X	X													
Rider No. 6				X												
Rider No. 7																(C)
Rider No. 8	X	X	X	X	X					X	X	X	X	X	X	
Rider No. 9						X	X	X	X							
Rider No. 10	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Rider No. 11				X		X										
Rider No. 12				X	X											
Rider No. 13				X												
Rider No. 14	X															
Rider No. 15																
Rider No. 15A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Rider No. 16				X	X	X	X	X								
Rider No. 17						X	X	X	X							
Rider No. 18	X	X	X	X	X	X	X									
Rider No. 19																
Rider No. 20	X	X	X	X	X	X	X	X	X	X						
Rider No. 21	X	X	X	X	X	X										
Rider No. 22	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Appendix A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Rider Titles:

Rider No. 1 — Retail Market Enhancement Surcharge
Rider No. 2 — Untransformed Service
Rider No. 3 — School and Government Service Discount Period
Rider No. 4 — Intentionally Left Blank (C)
Rider No 5 — Universal Service Charge
Rider No 6 — Temporary Service
Rider No. 7 — Intentionally Left Blank (C)
Rider No. 8 — Default Service Supply
Rider No. 9 — Day-Ahead Hourly Price Service
Rider No. 10 — State Tax Adjustment
Rider No. 11 — Street Railway Service
Rider No. 12 — Billing Option – Volunteer Fire Companies and Nonprofit Senior Citizen Centers
Rider No. 13 — General Service Separately Metered Electric Space Heating Service
Rider No. 14 — Residential Service Separately Metered Electric Space and Water Heating
Rider No. 15 — Intentionally Left Blank
Rider No. 15A — Phase III Energy Efficiency and Conservation Surcharge
Rider No. 16 — Service to Non-Utility Generating Facilities
Rider No. 17 — Emergency Energy Conservation
Rider No. 18 — Rates for Purchase of Electric Energy from Customer-Owned Renewable Resources Generating Facilities
Rider No. 19 — Intentionally Left Blank
Rider No 20 — Smart Meter Charge
Rider No. 21 — Net Metering Service
Rider No 22 — Distribution System Improvement Charge ("DSIC")
Appendix A — Transmission Service Charges

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 1 – RETAIL MARKET ENHANCEMENT SURCHARGE

(Applicable to all Rates)

The Retail Market Enhancement Surcharge ("RMES") is instituted as a cost recovery mechanism to recover all eligible costs incurred by the Company associated with implementing Commission-mandated activities, programs, projects, services etc. to enhance the competitive energy market in Pennsylvania. As an example, some of the mandated activities may be found in, but are not limited to, Commission Order's at Docket No. I-2011-2237952, Docket No. M-2013-2355751, and Docket No. M-2014-2401345. The RMES shall remain in effect to recover all expenses associated with Commission-mandated consumer education and retail market enhancement activities that are directed by the Commission to be recovered through the RMES or other Commission-approved mechanism and that are not otherwise being recovered in base rates. Consumer education activities shall also include those expenses to educate low-income and Customer Assistance Program ("CAP") customers about shopping in the retail market. The RMES will be recomputed annually and filed, to be effective June 1 of each year, unless the new rate is such a small change as to warrant no change in rates. The RMES shall be applied to all customers' bills. The RMES process will reconcile actual expense with revenue billed in accordance with this Rider. (C)

MONTHLY RETAIL MARKET ENHANCEMENT SURCHARGE RATES

(C)

Tariff Rate Class	Monthly RME Surcharge per Customer (cents)
Rate RS	(2.00)
Rate RH	(2.00)
Rate RA	(2.00)
Rate GS	(1.00)
Rate GM < 25 kW	(1.00)
Rate GM > 25 kW	(3.00)
Rate GMH < 25 kW	(1.00)
Rate GMH > 25 kW	(3.00)
Rates GL, GLH, L and HVPS	(1.00)
Rates AL, SE, UMS, SM, SH and PAL	(5.00)

CALCULATION OF RATES

The RMES, calculated independently for each customer class in this Tariff, shall be applied to all customers served under the Tariff. The RMES shall be determined in cents per month in accordance with the formula set forth below and shall be applied to all customers served during any part of a billing month:

$$\mathbf{RMES = [\ ((\ RME - e\ ) / (\ C * 12\ ) * 100\ )\ ] * [\ 1 / (\ 1 - T\ )\ ]} \quad \text{(C)}$$

Where **RMES** = Retail Market Enhancement Surcharge, a fixed charge in cents per month, to be billed to each customer served under the applicable Tariff rate class.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 1 – RETAIL MARKET ENHANCEMENT SURCHARGE – (Continued)

(Applicable to all Rates)

CALCULATION OF RATES – (CONTINUED)

RME = Projected annual expenses associated with retail market enhancement, consumer education activities and CAP customer education mandated by the Commission in dollars for each customer class for the filing year. CAP customer education dollars shall be assigned to the Residential customer class for cost recovery purposes. (C)

C = Projected average number of customers per customer class for the filing year.

e = The net overcollection or undercollection of the consumer education and retail market enhancement related expenses directed by the Commission as computed for each customer class as of the end of the reconciliation year.

T = The Pennsylvania Gross Receipts Tax in effect during the billing month, expressed in decimal form.

ANNUAL UPDATE

The RMES defined herein will be updated effective June 1 of each year unless, upon determination, the rates then in effect would result in a significant over or under collection. On or about January 31, the Company will file a reconciliation of the revenue and expense for the previous calendar year. On or about April 1 of the filing year, the Company will file revised RMES rates with the Commission defining rates in effect from June 1 to May 31 of the following year. These rates shall be determined based on the projected budget and number of customers for the filing year and the over or under collection of expenses based on actual RMES revenue and expense incurred for the previous calendar year, the reconciliation year. If it is determined that a significant over or under collection will occur, the Company shall file a revised RMES to become effective on no less than ten (10) day notice.

MISCELLANEOUS

No interest will be included in the RMES.

Rider No. 10 – State Tax Adjustment Surcharge (STAS) shall be applicable to the surcharge defined in this Rider.

The RMES will be added to the monthly Customer Charge of each rate schedule or added as a line item on the monthly bill, as applicable.

The Company shall file reconciliation statements annually.

The RMES shall be subject to review and audit by the Commission.

The RMES shall remain in effect until otherwise directed by the Commission and until the final reconciliation statement is approved and charges fully recovered.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) (C)

THIS PAGE INTENTIONALLY LEFT BLANK

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 – UNIVERSAL SERVICE CHARGE
(Applicable to Rate Schedules RS, RH and RA)

APPLICABILITY

The Universal Service Charge ("USC") is instituted as a cost recovery mechanism to recover the costs incurred by the Company to provide its Commission approved Universal Service and Energy Conservation Plan. The USC shall be applicable to all residential customers who take distribution service under Rate Schedules RS, RH and RA except for residential customers in the Company's Customer Assistance Program ("CAP"). The USC provides for the recovery of the costs, excluding internal administrative costs, associated with universal service programs provided by the Company to residential customers. The USC shall be determined to the nearest one-thousandth of one (1) cent per kilowatt-hour ("kWh") in accordance with the formula set forth below and shall be applied to all kilowatt-hours delivered during the billing month. The USC is a non-bypassable charge.

RATE

In addition to the charges provided in this Tariff, an amount of 0.972 cents per kilowatt-hour shall be added to the distribution energy charges per kilowatt-hour of each applicable rate schedule to determine the total per kilowatt-hour charge. The USC shall not be applicable to customers enrolled in the Company's CAP.

CALCULATION OF CHARGE

$$USC = [\,(US_c - Cr - E) / S_{Res}\,] * 100 * [1 / (1 - T)\,]$$

Where: USC = The charge, in cents per kilowatt-hour, to be applied to each kilowatt-hour delivered to all applicable non-CAP customers who take distribution service under the residential retail rate schedules under this Tariff.

US_c = Universal Service Program costs, which are the estimated direct and external administrative costs to be incurred by the Company to provide Universal Service to customers for the USC Computational Year. Such costs shall include, but are not limited to, preparation of the Needs Assessment, Universal Service Plan development, Impact Evaluation and educational materials. Universal Service Programs include the following programs which may change from time to time:

- Customer Assistance Program ("CAP"): CAP costs will be calculated to include the projected CAP discount and CAP program costs for the Computational Year. The total CAP discount will be based on the annual average discount from the previous year, the Reconciliation Year, multiplied by the projected average number of CAP program participants during the Computational Year. (C)

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 – UNIVERSAL SERVICE CHARGE - (Continued)
(Applicable to Rate Schedules RS, RH and RA)

CALCULATION OF CHARGE – (Continued)

The projected customer additions to the CAP program during the Computational Year will be based on the number of CAP customers receiving a discount at the end of the Reconciliation Year plus a projection of the average monthly number of CAP customers during the Computational Year. The projected number of CAP customers will include net additions to the program (additions minus exits), and a projection of customers enrolled through expected changes in policy (e.g. changes in the definition of poverty, changes in regulatory mandates). The projected CAP program costs will include the estimated costs for new applications, maintenance and annual recertification, and the projected CAP pre-program arrearages to be forgiven and written off during the USC Computational Year. **(C)** **(C)** **(C)** **(C)**

- Smart Comfort Program [Low Income Usage Reduction Program ("LIURP")]: LIURP costs will be calculated based on the projected number of homes that participate in the usage reduction program and the average cost per visit.
- Customer Assistance and Referral Evaluation Services ("CARES"): CARES costs will be calculated based on the projected annual Community Based Organization ("CBO") program costs and CBO costs for administering the program.
- Hardship Fund: Hardship Fund costs will be calculated based on the projected annual program costs and CBO costs for administering the program.
- Any other replacement or Commission-mandated Universal Service Program or low income program that is implemented during the Reconciliation or Computational Year.

Cr = A credit to reduce CAP customer discounts included in the USC to the extent that the monthly CAP enrollment level exceeds 39,088 customers. Specifically, the recoverable CAP discounts will be reduced by the number of CAP participants in excess of 39,088 times the average CAP credit and arrearage forgiveness costs times 10.43%. The participation level above which the offset shall be applied will be reset in each distribution rate case. **(C)** **(C)**

E = The over- or under- collection of actual Universal Service Program costs and revenue that result from the billing of the USC during the USC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly at the statutory legal rate of interest, from the month the over or under collection occurs to the effective month that the over collection is refunded or the under collection is recouped.

(C) – Indicates Change

STANDARD CONTRACT RIDERS – (Continued) (C)

THIS PAGE INTENTIONALLY LEFT BLANK

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting

(Rate Schedules SM, SH and PAL)

Lamp wattage as available on applicable rate schedule.

June 1, 2017 through May 31, 2018, June 1, 2018 through May 31, 2019 and (C)
January 1, 2019 through May 31, 2019 (C)

		Application Period					
Wattage	Nominal kWh Energy Usage per Unit per Month	06/01/2017 through 11/30/2017	12/01/2017 through 05/31/2018	06/01/2018 through 11/30/2018	12/01/2018 through 05/31/2019	01/01/2019 through 05/31/2019	(C)
Supply Charge ¢ per kWh		3.7939	3.8177	3.6653	X.XXXX	X.XXXX	
		Fixture Charge — $ per Month					
Mercury Vapor							
100	44	1.67	1.68	1.61	X.XX	—	
175	74	2.81	2.83	2.71	X.XX	—	
250	102	3.87	3.89	3.74	X.XX	—	
400	161	6.11	6.15	5.90	X.XX	—	
1000	386	14.64	14.74	14.15	X.XX	—	
High Pressure Sodium							
70	29	1.10	1.11	1.06	X.XX	—	
100	50	1.90	1.91	1.83	X.XX	—	
150	71	2.69	2.71	2.60	X.XX	—	
200	95	3.60	3.63	3.48	X.XX	—	
250	110	4.17	4.20	4.03	X.XX	—	
400	170	6.45	6.49	6.23	X.XX	—	
1000	387	14.68	14.77	14.18	X.XX	—	
Flood Lighting - Unmetered							
70	29	1.10	1.11	1.06	X.XX	—	
100	46	1.75	1.76	1.69	X.XX	—	
150	67	2.54	2.56	2.46	X.XX	—	
250	100	3.79	3.82	3.67	X.XX	—	
400	155	5.88	5.92	5.68	X.XX	—	
Light-Emitting Diode (LED) — Cobra Head							(C)
45	16	—	—	—	—	X.XX	
60	21	—	—	—	—	X.XX	
95	34	—	—	—	—	X.XX	
139	49	—	—	—	—	X.XX	
219	77	—	—	—	—	X.XX	
275	97	—	—	—	—	X.XX	
Light-Emitting Diode (LED) — Colonial							
48	17	—	—	—	—	X.XX	
83	29	—	—	—	—	X.XX	(C)
Light-Emitting Diode (LED) — Contemporary							
47	17	—	—	—	—	X.XX	
62	22	—	—	—	—	X.XX	(C)

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting — (Continued)

(Rate Schedules SM, SH and PAL)

Lamp wattage as available on applicable rate schedule.

June 1, 2019 through May 31, 2020 and June 1, 2020 through May 31, 2021

		Application Period				
Wattage	**Nominal kWh Energy Usage per Unit per Month**	**06/01/2019 through 11/30/2019**	**12/01/2019 through 05/31/2020**	**06/01/2020 through 11/30/2020**	**12/01/2020 through 05/31/2021**	
Supply Charge ¢ per kWh		X.XXXX	X.XXXX	X.XXXX	X.XXXX	
		Fixture Charge — $ per Month				
Mercury Vapor						
100	44	X.XXXX	X.XXXX	X.XX	X.XX	
175	74	X.XXXX	X.XXXX	X.XX	X.XX	
250	102	X.XXXX	X.XXXX	X.XX	X.XX	
400	161	X.XXXX	X.XXXX	X.XX	X.XX	
1000	386	X.XXXX	X.XXXX	X.XX	X.XX	
High Pressure Sodium						
70	29	X.XXXX	X.XXXX	X.XX	X.XX	
100	50	X.XXXX	X.XXXX	X.XX	X.XX	
150	71	X.XXXX	X.XXXX	X.XX	X.XX	
200	95	X.XXXX	X.XXXX	X.XX	X.XX	
250	110	X.XXXX	X.XXXX	X.XX	X.XX	
400	170	X.XXXX	X.XXXX	X.XX	X.XX	
1000	387	X.XXXX	X.XXXX	X.XX	X.XX	
Flood Lighting - Unmetered						
70	29	X.XXXX	X.XXXX	X.XX	X.XX	
100	46	X.XXXX	X.XXXX	X.XX	X.XX	
150	67	X.XXXX	X.XXXX	X.XX	X.XX	
250	100	X.XXXX	X.XXXX	X.XX	X.XX	
400	155	X.XXXX	X.XXXX	X.XX	X.XX	
Light-Emitting Diode (LED) — Cobra Head						**(C)**
45	16	X.XX	X.XX	X.XX	X.XX	
60	21	X.XX	X.XX	X.XX	X.XX	
95	34	X.XX	X.XX	X.XX	X.XX	
139	49	X.XX	X.XX	X.XX	X.XX	
219	77	X.XX	X.XX	X.XX	X.XX	
275	97	X.XX	X.XX	X.XX	X.XX	
Light-Emitting Diode (LED) — Colonial						
48	17	X.XX	X.XX	X.XX	X.XX	
83	29	X.XX	X.XX	X.XX	X.XX	**(C)**
Light-Emitting Diode (LED) — Contemporary						
47	17	X.XX	X.XX	X.XX	X.XX	
62	22	X.XX	X.XX	X.XX	X.XX	**(C)**

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

CONTINGENCY PLAN

In the event Duquesne receives bids for less than all Tranches or the Commission does not approve all or some of the submitted bids or in the event of supplier default, then Duquesne will provide the balance of the default supply for commercial and industrial customers through purchases in the PJM spot markets until such time that a different contingency plan is approved by the Commission. Duquesne will submit to the Commission within fifteen (15) days after any such occurrence an emergency plan to handle any default service shortfall. All costs associated with implementing the contingency plan will be included as part of the DSS described in the section below, "Calculation of Rate."

CALCULATION OF RATE

DSS rates shall be determined based on the formula described in this section. The DSS shall be filed with the Commission no less than sixty (60) days prior to the start of the next Application Period as defined under the Default Service Supply Rate section of this Rider. Rates are reconciled on a semi-annual basis in accordance with the Default Service Supply Rate section of this Rider. The rates shall include an adjustment to reconcile revenue and expense for each Application Period. The DSS shall be determined to the nearest one-thousandth of one (1) mill per kilowatt-hour in accordance with the formula set forth below and shall be applied to all kilowatt-hours billed for default service provided during the billing month:

$$DSS = [(RFP + SLR + (DSS_a + E))/S) * F] * [1/(1 - T)]$$

Where:

DSS = Default Service Supply rate, converted to cents per kilowatt-hour, to be applied to each kilowatt-hour supplied to customers taking default service from the Company under this Rider.

RFP = The weighted average of the winning bids received in a competitive request for proposal for each customer class identified above and described in the "Default Service Supply Rate" section and adjusted for customer class transmission and distribution line losses. The request for proposal shall be conducted as described in "Procurement Process."

DSSa = The total estimated direct and indirect costs incurred by the Company to acquire DSS from any source on behalf of customers described above in the "Procurement Process." The Application Period shall be for each period over which the DSS, as computed, will apply. Projections of the Company's costs to acquire default supply for the Application Period shall include all direct and indirect costs of generation supply to be acquired by the Company from any source plus any associated default service supply-related procurement and administration costs. Company costs may also include the expenses to support time-of-use ("TOU") programs offered by EGSs. Time-of-use expenses will be assigned to the applicable customer class for recovery through this Rider. Default service supply-related costs shall include the cost of preparing the company's default service plan filing and working capital costs associated with default service supply. The Company will recover these costs over the default service plan period as defined (C)
in the Commission's order at Docket No. R-2018-3000124.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

MONTHLY CHARGES – (Continued)

PJM Ancillary Service Charges and Other PJM Charges – (Continued)

PJM_S= PJM Surcharge is a pass-through of the charges incurred by the Company for grid management and administrative costs associated with membership and operation in PJM. These are the charges incurred by the Company under PJM Schedules 9 and 10 to provide hourly price service.

R_D = Reactive supply service charge in $/MW-day to serve the customer's load as calculated under the PJM Tariff Schedule 2.

B_D = Blackstart service charge in $/MW-day to serve the customer's load as calculated under the PJM Tariff Schedule 6A.

Fixed Retail Administrative Charge

FRA = The Fixed Retail Administrative Charge in $ per MWH. The Fixed Retail Administrative Charge consists of the sum of administrative charges for the suppliers providing hourly price service (as determined by a competitive solicitation process) and for the Company to obtain supply and administer this service. Default service supply-related costs shall include the cost of preparing the company's default service plan filing and working capital costs associated with default service supply. The Company will recover these costs over the default service plan period as defined in the Commission's order at Docket No.R-2018-3000124. **(C)**

The supplier charges shall be based on the winning bids in the Company's most recent solicitation for supply of hourly price default service.

The Company's administrative charges shall be based on an amortization of the costs incurred by the Company to acquire generation supply from any source for the Large C&I Customer Class during the most recent twelve-month (12-month) period ended May 31st (as determined by amortizing such costs over a 12-month period) plus the amortization of the cost of administering the hourly price service over the duration of the default service plan, including any unbundled costs of preparing the Company's default service plan filing and working capital costs associated with default service supply.

This charge shall also include the Company's costs associated with any Commission approved solar contracts and its administration, if applicable, in $ per MWh. The proceeds of any solar energy, capacity, ancillary services and solar AECs that are acquired and in excess of those allocated to default service suppliers, and sold into the market, will be netted against solar contract costs.

Application Period	FRA $/MWH
June 1, 2017 through May 31, 2018	$1.77
June 1, 2018 through May 31, 2019	$1.74
June 1, 2019 through May 31, 2020	$X.XX
June 1, 2020 through May 31, 2021	$X.XX

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 10 - STATE TAX ADJUSTMENT

(Applicable to All Rates)

In addition to the charges provided in this Tariff, a two-part surcharge will apply to all bills rendered by the Company, 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.

Part 1 of the surcharge, at a rate of 0.0000% will include Capital Stock Tax, Corporate Net Income Tax, and Public Utility Realty Tax, which will be applied to the distribution charges of customer bills. **(D)**

Part 2 of the surcharge, at a rate of 0.0000% will include Gross Receipts Tax and will be applied to all portions of customer bills.

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 December 22, 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.

(D) – Indicates Decrease

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - GENERAL SERVICE SEPARATELY METERED ELECTRIC SPACE HEATING SERVICE

(Applicable to Rate GS/GM)

AVAILABILITY

Available for separately metered circuitry connected to electric space heating devices limited to electric resistance heaters, add-on heat pumps, heat pump compressors, system fans, pumps and controls except where the customer uses the Company's service for water heating, then water heating may also be included on the circuit. The space heating service may be provided at the same voltage as other electric service.

MONTHLY RATE

ENERGY CHARGES

For the billing months of November through April, all kilowatt-hours will be billed the applicable kilowatt-hour Monthly Energy Charges of Rate GS/GM. The applicable Monthly Energy Charge will be determined based on the customer's monthly demand, including the demand associated with the separately metered electric space (C)
heating, as described in the Electric Charges section of Rate GS/GM. Customers who purchase their electric supply requirements from the Company will be billed the applicable transmission energy charges of Appendix A and the applicable energy charges of Rider No. 8 – Default Service Supply. For the billing months of May through October, Rate GS/GM will apply.

METER CHARGE..$13.21 per month

The customer will be responsible for any necessary wiring, structural or equipment changes or relocations to allow the isolation and metering of the electric space heating system.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES

(Applicable to GM < 25, GM ≥ 25, GMH < 25, GMH ≥ 25, GL, GLH and L Rates) (C)

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

A. DEFINITIONS

Supplementary Service is distribution services provided by the Company to a non-utility generating facility and regularly used in addition to that electric energy which the non-utility generating facility generates itself. The Company's regular and appropriate General Service Rates will be utilized for billing for Supplementary Service. (C)

Back-Up Service is distribution services provided by the Company to a non-utility generating facility during any outage of the non-utility generating facility's electric generating equipment or otherwise, to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment. (C)

Base Period is the twelve consecutive monthly billing periods applicable to the customer ending one month prior to the installation of new on-site generation or increase in capacity to existing on-site supply.

Contract Demand is the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer for Back-Up Service. A Contract Demand may be established for Supplementary Service to the customer's facility. (C)

Supplementary Service Billing Determinants is the kW specified in the Contract with the customer for Supplementary Service. (C)

Back-Up Service Billing Determinants is the kW specified in the Contract with the customer for Back-Up Service. (C)

Distribution Base Period Billing Determinants are the billing demand (kW) for the month in the Base Period corresponding to the current billing month under which the on-site generation is operable. For new customers, the Company will use existing procedures to estimate Base Period Billing Determinants. (C)

Supply Billing Determinants for customers not being served by an Electric Generation Supplier ("EGS"), Rate Schedules GL, GLH, and L shall be the billing determinates for the current billing month then in effect under Rider No. 9 – Day-Ahead Hourly Price Service. Supply Billing Determinants for customers on Rate Schedule GS/GM and GMH shall be the billing determinants for the current billing month then in effect under Rider No. 8 – Default Service Supply. (C)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to GM < 25, GM ≥ 25, GMH < 25, GMH ≥ 25, GL, GLH and L Rates) (C)

B. BACK-UP SERVICE (C)

The Company will supply Back-Up Service at the following rates: (C)

DISTRIBUTION

A distribution charge of $8.00 per kW shall be applied to the Back-Up Service Billing Determinants. (I)(C)

The distribution charges will be applied in each month based on the customer's Contract Demand without regard to actual usage. (C)
(C)

If actual usage of Back-Up Service exceeds zero for more than 15% of the hours in any Base Period, then those hours above the 15% threshold will be counted toward the billing on the customer's applicable general service rate, including all ratchets applicable. (C)

If a customer's Back-Up Service requirement at any time exceeds the customer's Back-Up Contract Demand by 5% or more, the actual Back-Up Service requirement measured in kW demand will become the customer's new Back-Up Contract Demand for the remaining term of the back-up contract. If a customer's actual Back-Up Service requirement at any time exceeds the customer's Back-Up Contract Demand by 10% or more, the customer will be assessed a fee equal to the difference between the actual Back-Up Service requirement at the time and the Back-Up Contract Demand multiplied by two times the applicable charge per kilowatt. (C)(C)(C)(C)(C)(C)

SUPPLY (C)

In any month that the Company provides energy to back up the customer's equipment, supply service shall be supplied and billed under Rider No. 9 for customers with Contract Demand of 300 kW or more. For customers having Contract Demand of less than 300 kW, the Company will bill the applicable supply demand and energy charges then in effect under Rate Schedule GS/GM.

C. INTERCONNECTION

Each non-utility generating facility will be required to install at its expense or pay in advance to have the Company 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 the Company's General Service Rates, except as noted below. Any such equipment to be installed by the non-utility generating facility must be reviewed and approved in writing by the Company prior to installation. Nothing in this Rider shall exempt a new customer from the application of Rule No. 7 and Rule No. 9 regarding Supply Line Extensions and Relocation of Facilities.

However, customers may elect to pay the cost of existing or newly required transformation equipment that is over and above that equipment necessary for the Company to supply the customer with its contracted Supplemental Service via a monthly charge rather than in total at the onset of the contract. The monthly charge for transformation equipment for customers with contract demand under this rider of 5,000 kW or more will be determined by the Company on a case-by-case basis (C)(C)

(C) – Indicates Change

RIDER NO. 20 – SMART METER CHARGE

(Applicable to Rates RS, RH, RA, GS/GM, GMH, GL, GLH, L, HVPS and AL)

PURPOSE

The Smart Meter Charge ("SMC") is instituted as a cost recovery mechanism to recover all costs to implement the Company's Smart Meter Procurement and Implementation Plan ("Plan"). The SMC has been added per Commission Order at Docket No. M-2009-2123948. Act 129 ("Act") became effective November 14, 2008, requiring all Pennsylvania electric distribution companies ("EDCs") with more than 100,000 customers to implement smart meters. Act 129 set forth the timeline for implementation, the definition of smart meters and the provisions for full and current cost recovery of all costs incurred by EDCs to install and make fully functional a smart meter system defined in and required by Act 129. The Company filed its Plan on August 14, 2009, in compliance with the Act, including this Charge and provisions for cost recovery. This Charge shall be updated as described below to recover all costs associated with implementing the Plan.

The SMC is a non-bypassable charge and shall be applicable to the monthly bill of all metered customers based on the number of meters installed at the premise.

ELIGIBLE COSTS

The SMC recovers all eligible costs incurred by the Company to implement smart meter technology and the supporting infrastructure. Eligible costs, described in 66 Pa. C.S. § 2807(f), include capital and expense items relating to all Plan elements, equipment and facilities, as well as all related administrative costs. Plan costs include, but are not limited to, capital expenditures for any equipment and facilities that may be required to implement the Plan, as well as depreciation, operating and maintenance expenses, a return component based on the EDC's weighted cost of capital and taxes. In general, eligible administrative costs include, but are not limited to, incremental costs relating to Plan development, cost analysis, measurement and verification and reporting. The costs associated with testing, upgrades, maintenance and personnel training are considered eligible costs.

MONTHLY SMART METER CHARGE

Meter Type	Monthly Charge Per Meter	
Single-Phase	$0.00	(D)
Poly-Phase	$0.00	(D)

The SMC, calculated independently for each meter type, shall be applied to all applicable customers served under the Tariff. Customers will be billed based on the number of meter types installed at their premise. Customers with multiple meters will incur multiple charges. The SMC shall be determined in dollars and cents per month per meter in accordance with the formula described in the "Calculation of Charge" section and shall be applied to all applicable customers served during any part of a billing month.

(D) – Indicates Decrease

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE

(Applicable to Rates RS, RH, RA, GS/GM, GMH and GL)

PURPOSE

This Rider sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY

This Rider applies to renewable customer-generators served under Rate Schedules RS, RH, RA, GS/GM, GMH and GL who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rider is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate RS, RH or RA) or not larger than 3,000 kilowatts at other customer service locations (Rate GS/GM, GMH and GL), except for Customers whose systems are above three megawatts and up to five megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a micro grid is in place for the primary or secondary purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers ("IEEE") and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rider is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rider is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule RS, RH, RA, GS/GM, GMH and GL.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter, which can measure and record the flow of electricity in both directions at the same rate, for (C) all billing-related purposes, including measurement of customer-generator's net electricity (C) consumption. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense. Except for those customer-generator facilities interconnected, or for (C) which the Company has received a completed Part 1 Interconnection Application, prior to January 1, 2019, such facility shall also be equipped with an additional meter (the "generation meter"), which shall be installed at Company expense and which shall be used to record outbound flow of electricity.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 22 – DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

(Applicable to All Rates)

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply consistent with the Commission Order entered September 15, 2016, at Docket No. P-2016-2540046 approving the Distribution System Improvement Charge ("DSIC"). **(D)**

GENERAL DESCRIPTION

PURPOSE

To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

ELIGIBLE PROPERTY

The DSIC-eligible property will consist of the following:

— Poles and towers (account 364);

— Overhead conductors (account 365) and underground conduit and conductors (accounts 366 and 367);

— Line transformers (account 368) and substation equipment (account 362);

— Any fixture or device related to eligible property listed above including insulators, circuit breakers, fuses, reclosers, grounding wires, cross arms and brackets, relays, capacitors, converters and condensers;

— Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and

— Other related capitalized costs.

EFFECTIVE DATE

The DSIC will become effective October 1, 2016.

(D) – Indicates Decrease

APPENDIX A – (Continued)

TRANSMISSION SERVICE CHARGES – (Continued)

(Applicable to All Rates)

MONTHLY RATES – (Continued)

Rate Class	Energy Charge $/kWh	Demand Charge $/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture	Monthly Charge Per Fixture	
			Rate Class			
By Wattage			SH	PAL	SM	
Flood Lighting - Unmetered						
70			—	$0.18	—	
100			—	$0.29	—	
150			—	$0.42	—	
250			—	$0.63	—	
400			—	$0.98	—	
Light-Emitting Diode (LED) — Cobra Head						(C)
45			—	$0.00	$0.00	
60			$0.00	$0.00	$0.00	
95			$0.00	$0.00	$0.00	
139			$0.00	$0.00	$0.00	
219			$0.00	$0.00	$0.00	
275			—	$0.00	$0.00	
Light-Emitting Diode (LED) — Colonial						(C)
48			—	$0.00	$0.00	
83			—	$0.00	$0.00	
Light-Emitting Diode (LED) — Contemporary						(C)
47			—	$0.00	$0.00	
62			—	$0.00	$0.00	

BILLING DEMAND

Billing Demand subject to Transmission Service Charges for customers taking service under Rate Schedules GS/GM and GMH shall be the same as that determined for distribution and supply charges under the applicable rate schedules.

Billing Demand subject to Transmission Service Charges for Customers taking service under Rate Schedules GL, GLH, L, HVPS and UMS shall be the customer's daily network service coincident peak load contribution in MW. This quantity is determined based on the customer's load coincident with the annual peak of the Duquesne Zone (single coincident peak) as defined in the PJM Tariff Section 34.1.

ANNUAL UPDATE

The Transmission Service Charges (TSC) defined herein will be updated effective June 1st of each calendar year or more often upon determination that the rates then in effect would result in a significant over or under collection. On or about May 1st, the Company will file revised TSC rates with the PA Public Utility Commission (Commission) defining rates in effect from June 1 to May 31 of the following year, the computation year. These rates shall be determined based on the projected revenue requirement for the computation year, the projected cost of PJM charges and the over or under collection of expenses based on actual TSC revenue and expense incurred up to March 1 of each filing year. The revenue requirement and over or under collection shall be allocated to each rate class based on the class contribution to the Company's coincident peak load (1CP) and Default Service share of the 1CP load from the previous calendar year. The costs for ancillary services and PJM administrative expenses are included in the Default Service Supply rates defined in Rider No. 8. The costs for ancillary services and PJM administrative expenses for rate classes GL, GLH, L and HVPS will be billed in accordance with Rider No. 9. The rates applicable to each Rate Schedule shall be determined in accordance with the following formulas.

(C) – Indicates Change

Exhibit No. DBO-2

SUPPLEMENT NO. ~~173~~174
TO ELECTRIC – PA. P.U.C. NO. 24

DUQUESNE LIGHT CO.

SCHEDULE OF RATES

For Electric Service in Allegheny and Beaver Counties

(For List of Communities Served, see Pages No. 4 and 5)

Issued By

DUQUESNE LIGHT COMPANY
411 Seventh Avenue
Pittsburgh, PA 15219

Richard Riazzi
President and Chief Executive Officer

ISSUED: March 28, 2018 EFFECTIVE: May 29, 2018

Filed at Docket No. R-2018-3000124

NOTICE

THIS TARIFF SUPPLEMENT MAKES CHANGES TO THE TABLE OF CONTENTS, RULES AND REGULATIONS, RATE SCHEDULES, RIDERS AND APPENDIX A AND MAKES INCREASES AND DECREASES TO THE RATES CONTAINED IN THE RATE SCHEDULES, RIDERS AND APPENDIX A.

See Page Two

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

List of Modifications — **Page No. 2**

Pages No. 2A through 2R were added to the Tariff.

Table of Contents — **Thirty-Fifth Revised Page No. 3**
Standard Contract Riders — **Cancelling Thirty-Fourth Revised Page No. 3**

Pages No. 2A through 2R were added to the Table of Contents.

The Table of Contents has been updated to reflect the addition of Original Page No. 70A.

The Table of Contents has been updated to reflect the addition of Original Page No. 73A.

The Table of Contents has been updated to reflect the addition of Original Page No. 78A.

The Table of Contents has been updated to reflect the removal of Rider No. 4 – Budget Billing HUD Finance Multi-Family Housing. Rider No. 4 has been revised to read "This Page Intentionally Left Blank."

The Table of Contents has been updated to reflect the removal of Rider No. 7 – SECA Charge. Rider No. 7 has been revised to read "This Page Intentionally Left Blank."

Rules and Regulations — **Fifth Revised Page No. 6**
The Electric Service Tariff — **Cancelling Fourth Revised Page No. 6**

Rule No. 2.1 Rules and Regulations has been added to clarify tariff applicability to all persons taking service.

Rule No. 2.2 Statement by Agents has been added to clarify that Company representatives cannot modify tariff obligations.

Rule No. 3 Application has been revised to update and define the Company's standard nominal service delivery voltages for installations prior to and effective on January 1, 2019.

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions — **Fifth Revised Page No. 6**
Cancelling Fourth Revised Page No. 6

Rule No. 3.1 Definitions (1) Aggregator or Market Aggregator and (2) Applicant previously shown on Fourth Revised Page No. 6, Cancelling Third Revised Page No. 6 in Supplement No. 107 has been moved to Sixth Revised Page No. 7, Cancelling Fifth Revised Page No. 7 in Supplement No. 174 to accommodate the addition of and revision to rules.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions — **Sixth Revised Page No. 7**
Cancelling Fifth Revised Page No. 7

Rule No. 3.1 Definitions along with (1) Aggregator or Market Aggregator and (2) Applicant previously shown on Fourth Revised Page No. 6, Cancelling Third Revised Page No. 6 in Supplement No. 107 has been moved to Sixth Revised Page No. 7, Cancelling Fifth Revised Page No. 7 in Supplement No. 174 to accommodate the addition of and revision to rules.

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions — **Sixth Revised Page No. 7**
Cancelling Fifth Revised Page No. 7

Language has been revised in Definition (8) Customer to clarify the definition of "Customer."

Rules and Regulations
The Electric Service Tariff
Rule No. 3.1 Definitions — **Sixth Revised Page No. 8**
Cancelling Fifth Revised Page No. 8

Currently existing definitions for Rate Ready and Renewable Resource have been moved down to place in alphabetical order.

The definition for Summary Billing has been added.

Definitions have been renumbered to place in alphabetical order and to accommodate the addition of a definition of Summary Billing.

Rules and Regulations
Contracts, Deposits and Advance Payments — **Fourth Revised Page No. 9**
4. Contracts — **Cancelling Third Revised Page No. 9**

Language has been inserted at the end of the first sentence of paragraph one to clarify that Nonstandard Service costs can be recoverable through special rate contracts.

Language has been revised to adjust instances where the Company can enter into special rate contracts and the duration of special contracts.

Information previously shown on Second Revised Page No. 9A, Cancelling First Revised Page No. 9A in Supplement No. 72 has been moved to the end of Fourth Revised Page No. 9, Cancelling Third Revised Page No. 9 in Supplement No. 174.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
Contracts, Deposits and Advance Payments — **Second Revised Page No. 9A**
4. Contracts — **Cancelling First Revised Page No. 9A**

Second Revised Page No. 9A, Cancelling First Revised Page No. 9A in Supplement No. 72 is being deleted as it is no longer necessary. Information previously shown on Second Revised Page No. 9A, Cancelling First Revised Page No. 9A in Supplement No. 72 has been moved to the end of Fourth Revised Page No. 9, Cancelling Third Revised Page No. 9 in Supplement No. 174.

Rules and Regulations
Contracts, Deposits and Advance Payments — **Fourth Revised Page No. 10**
5. Deposits and Advance Payments — **Cancelling Third Revised Page No. 10**

Language has been inserted to clarify that EGS charges, where applicable, are included in the calculation of a security deposit.

Language has been inserted to clarify how the Company evaluates creditworthiness of non-residential customers.

Language has been inserted to clarify the Company process for requiring security deposits from non-residential customers.

Rules and Regulations
Contracts, Deposits and Advance Payments — **Second Revised Page No. 10A**
5. Deposits and Advance Payments — **Cancelling First Revised Page No. 10A**

The paragraph referencing "seasonal service" has been removed as obsolete. The Company no longer provides a separate seasonal service rate.

Language has been inserted to explain that security deposit requirements for residential customers do not extend to non-residential accounts.

Rules and Regulations
Payment of Outstanding Balance — **Second Revised Page No. 10A**
5a. Payment of Outstanding Balance — **Cancelling First Revised Page No. 10A**

Language has been inserted to clarify customer/applicant responsibility for outstanding account balances and the documentation required to establish service.

Rules and Regulations
Installation of Service — **Third Revised Page No. 11**
6. Installation Rules — **Cancelling Second Revised Page No. 11**

Language has been inserted to clarify limited exception for Company-approved Nonstandard Service.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations	
Installation of Service	**Third Revised Page No. 11**
6.1 Service Point	**Cancelling Second Revised Page No. 11**

Rule No. 6.1 Service Point has been added to comply with 52 Pa. Code § 57.28 (a) Electric Safety Standards (Docket No. L-2015-2500632).

Rule No. 7 Supply Line Extensions previously shown on Second Revised Page No. 11, Cancelling First Revised Page No. 11 in Supplement No. 35 has been moved to Original Page No. 11A in Supplement No. 174 in order to accommodate the addition of Rule No. 6.1 Service Point.

Rules and Regulations	
Installation of Service	
7. Supply Line Extensions	**Original Page No. 11A**

Original Page No. 11A has been added to Tariff No. 24.

Rule No. 7 Supply Line Extensions previously shown on Second Revised Page No. 11, Cancelling First Revised Page No. 11 in Supplement No. 35 has been moved to Original Page No. 11A in Supplement No. 174 in order to accommodate the addition of Rule No. 6.1 Service Point.

Language has been inserted in Rule No. 7 Supply Line Extensions, B. Overhead Areas (1) to provide additional customer clarity in regard to the length of single-phase, lower-voltage supply line extensions.

Rules and Regulations	
Installation of Service	
7. Supply Line Extensions	**Second Revised Page No. 12**
B. Overhead Areas – (Continued)	**Cancelling First Revised Page No. 12**

Rule No. 7 Supply Line Extensions, B. Overhead Areas (3) has been removed to clarify the Company's ability to recover costs of Nonstandard Service.

Rules and Regulations	
Installation of Service	
7. Supply Line Extensions	**Second Revised Page No. 13**
C. Underground Areas – (Continued)	**Cancelling First Revised Page No. 13**

Rule No. 7 Supply Line Extensions, C. Underground Areas (3) has been removed to clarify the Company's ability to recover costs of Nonstandard Service.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
Installation of Service
7. Supply Line Extensions — **Second Revised Page No. 14**
E. Revenue Guarantees — **Cancelling First Revised Page No. 14**

Language has been inserted to provide that costs other than those associated with service line extensions may be included in a revenue guarantee.

Rules and Regulations
Installation of Service
7. Supply Line Extensions — **Second Revised Page No. 14**
E. Revenue Guarantees — **Cancelling First Revised Page No. 14**

Language has been inserted into Rule No. 7 Supply Line Extensions, E. Revenue Guarantees and E. Revenue Guarantees (2) to clarify the revenue guarantee payment and refund process.

Rules and Regulations
Installation of Service — **Second Revised Page No. 15**
8. Nonstandard Service — **Cancelling First Revised Page No. 15**

Rule No. 8 Connection Charges as shown on First Revised Page No. 15, Cancelling Original Page No. 15 in Supplement No. 2, has been renamed to Rule No. 8 Nonstandard Service in Supplement No. 174.

Language has been revised and inserted to clarify the Company's ability to recover costs of Nonstandard Service.

Rules and Regulations
Installation of Service — **Second Revised Page No. 15**
9. Relocations of Facilities — **Cancelling First Revised Page No. 15**

Rule No. 9 Relocations of Facilities, A. Pole Removal or Relocation for Residential Customers (2), (3) and (4) and B. Other Company Facilities for all Customers previously shown on First Revised Page No. 15, Cancelling First Revised Page No. 15 in Supplement No. 2 has been moved to Original Page No. 15A in Supplement No. 174 in order to accommodate the revisions to Rule No. 8 Nonstandard Service.

Rules and Regulations
Installation of Service
9. Relocations of Facilities – (Continued) — **Original Page No. 15A**

Original Page No. 15A has been added to Tariff No. 24.

Rule No. 9 Relocations of Facilities, A. Pole Removal or Relocation for Residential Customers (2), (3) and (4) and B. Other Company Facilities for all Customers previously shown on First Revised Page No. 15, Cancelling First Revised Page No. 15 in Supplement No. 2 has been moved to Original Page No. 15A in Supplement No. 174 in order to accommodate the revisions to Rule No. 8 Nonstandard Service.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES

Rules and Regulations
Measurement and Use of Service — **Fifth Revised Page No. 22**
14.2 Customer Request for Special Metering – (Continued) — **Cancelling Fourth Revised Page No. 22**

Language has been removed as obsolete.

Rules and Regulations
Measurement and Use of Service — **Fifth Revised Page No. 22**
14.3 Sub-Metering — **Cancelling Fourth Revised Page No. 22**

Rule No. 14.3 Sub-Metering has been removed as unnecessary.

Rules and Regulations
Bills and Net Payment Periods — **Fifth Revised Page No. 23**
18. Redistribution — **Cancelling Fourth Revised Page No. 23**

Language has been modified for clarity.

Rules and Regulations
Bills and Net Payment Periods — **Fifth Revised Page No. 23**
20.2 Summary Billing — **Cancelling Fourth Revised Page No. 23**

Rule No. 20.2 Summary Billing has been added to explain the availability of Summary Bills to qualifying customers.

Rules and Regulations — **Sixth Revised Page No. 23A**
Bills and Net Payment Periods — **Cancelling Fifth Revised Page No. 23A**

Rule No. 20.2 Bills (as numbered in Fifth Revised Page No. 23A, Cancelling Fourth Revised Page No. 23A in Supplement No. 128) has been renumbered to Rule No. 20.3 and Rule No. 20.3 Budget Payment Plan for Residential Customers (as numbered in Fifth Revised Page No. 23A, Cancelling Fourth Revised Page No. 23A in Supplement No. 128) has been renumbered to Rule No. 20.4 to accommodate the addition of Rule No. 20.2 Summary Billing in Supplement No. 174.

Rules and Regulations
Bills and Net Payment Periods — **Sixth Revised Page No. 23A**
20.4 Budget Payment Plan for Residential Customers — **Cancelling Fifth Revised Page No. 23A**

Language has been inserted to clarify budget billing for customers of bill-ready EGSs.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations
Company Property on Customer's Premises — **Fifth Revised Page No. 24**
22 Access to Premises — **Cancelling Fourth Revised Page No. 24**

Language has been inserted to ensure Company access to facilities, particularly in the event of emergency, and to clarify that failure to provide access is grounds for termination.

Rules and Regulations
Company Property on Customer's Premises — **Fifth Revised Page No. 24**
22.1 Vegetation Management and Right-Of-Way — **Cancelling Fourth Revised Page No. 24**

Rule No. 22.1 Vegetation Management and Right-Of-Way has been added to clarify customer and Company responsibilities regarding vegetation management around Company facilities.

Rules and Regulations
Company Property on Customer's Premises — **Fifth Revised Page No. 24**
25 Repairs or Losses — **Cancelling Fourth Revised Page No. 24**

Rule No. 25 Repairs or Losses previously shown on Fourth Revised Page No. 24, Cancelling Third Revised Page No. 24 in Supplement No. 100 has been moved to First Revised Page No. 24A, Cancelling Original Page No. 24A in Supplement No. 174 in order to accommodate the addition of Rule No. 22.1 Vegetation Management and Right-Of-Way.

Rules and Regulations — **First Revised Page No. 24A**
Discontinuance, Curtailment or Interruption of Electric Service — **Cancelling Original Page No. 24A**

The "Bills and Net Payment Periods – (Continued)" heading has been removed as it is not applicable to the section.

Rules and Regulations
Company Property on Customer's Premises — **First Revised Page No. 24A**
25 Repairs or Losses — **Cancelling Original Page No. 24A**

Rule No. 25 Repairs or Losses previously shown on Fourth Revised Page No. 24, Cancelling Third Revised Page No. 24 in Supplement No. 100 has been moved to First Revised Page No. 24A, Cancelling Original Page No. 24A in Supplement No. 174 in order to accommodate the addition of Rule No. 22.1 Vegetation Management and Right-Of-Way.

Rules and Regulations
Discontinuance, Curtailment or Interruption of Electric Service — **Third Revised Page No. 25**
27.1 Death of A Residential Customer — **Cancelling Second Revised Page No. 25**

Rule No. 27.1 Death of A Residential Customer has been added to clarify the Company's process for ending service in the name(s) of customers reported as deceased.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rules and Regulations
Discontinuance, Curtailment or Interruption of Electric Service — **Second Revised Page No. 26**
33 Inaccessibility — **Cancelling First Revised Page No. 26**

Language has been revised and inserted to clarify that failure to provide Company representatives access to Company facilities is grounds for termination, consistent with Rule No. 22.

Rules and Regulations
General Provisions — **Fourth Revised Page No. 31A**
46. Provision of Load Data — **Cancelling Third Revised Page No. 31A**

Language has been modified to reflect current business practice. Rule No. 46 has been revised to comply with Commission Order dated October 11, 2012, at Docket No. R-2012-2320394. The reference to "once each calendar year" has been updated to "five (5) requests in a calendar year."

Rate GS/GM – General Service Small and Medium — **Eighth Revised Page No. 40**
Cancelling Seventh Revised Page No. 40

Seventh Revised Page No. 42
Cancelling Sixth Revised Page No. 42

The design of the Monthly Rate section, including sub-section titling, has been modified for customer clarity.

Rate GS/GM – General Service Small and Medium — **Eighth Revised Page No. 41**
Cancelling Seventh Revised Page No. 41

Language has been modified to clarify customer rate assignments among Rate GS, Rate GM < 25 kW and Rate GM ≥ 25 kW.

The last three paragraphs of the "Electric Charges" section as well as the "Minimum Charge" section previously shown on Seventh Revised Page No. 41, Cancelling Sixth Revised Page No. 41 in Supplement No. 35 has been moved to Seventh Revised Page No. 42, Cancelling Sixth Revised Page No. 42 in Supplement No. 174 to accommodate the addition of the rate assignment language.

Rate GS/GM – General Service Small and Medium — **Seventh Revised Page No. 42**
Cancelling Sixth Revised Page No. 42

The last three paragraphs of the "Electric Charges" section as well as the "Minimum Charge" section previously shown on Seventh Revised Page No. 41, Cancelling Sixth Revised Page No. 41 in Supplement No. 35 has been moved to Seventh Revised Page No. 42, Cancelling Sixth Revised Page No. 42 in Supplement No. 174 to accommodate the addition of the rate assignment language.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate GMH – General Service Medium Heating — **Eighth Revised Page No. 43**
Cancelling Seventh Revised Page No. 43

Ninth Revised Page No. 44
Cancelling Eighth Revised Page No. 44

The design of the Monthly Rate section has been modified for customer clarity.

Rate GMH – General Service Medium Heating — **Ninth Revised Page No. 44**
Cancelling Eighth Revised Page No. 44

Language has been modified to clarify customer rate assignments between Rate GM < 25 kW and Rate GM ≥ 25 kW.

Rate GL – General Service Large — **Eighth Revised Page No. 47**
Cancelling Seventh Revised Page No. 47

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate GLH – General Service Large Heating — **Eighth Revised Page No. 50**
Cancelling Seventh Revised Page No. 50

Fifth Revised Page No. 51
Cancelling Fourth Revised Page No. 51

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate L – Large Power Service — **Eighth Revised Page No. 53**
Cancelling Seventh Revised Page No. 53

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate L – Large Power Service — **Eighth Revised Page No. 53**
Cancelling Seventh Revised Page No. 53

Language and relevant rate charges have been removed as "Service Voltage 138 kV and Greater" is no longer applicable to Rate L – Large Power Service.

Rate L – Large Power Service — **Second Revised Page No. 56**
Cancelling First Revised Page No. 56

Language has been modified from "his" to "its."

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate HVPS – High Voltage Power Service — **Eighth Revised Page No. 57**
Cancelling Seventh Revised Page No. 57

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate HVPS – High Voltage Power Service — **Eighth Revised Page No. 57**
Cancelling Seventh Revised Page No. 57

Fourth Revised Page No. 58
Cancelling Third Revised Page No. 58

Second Revised Page No. 60
Cancelling First Revised Page No. 60

Language has been modified to lower the kilowatts from "greater than 30,000" to "greater than "5,000" in order to move Rate L – Large Power Service 138 kV and Greater customers to Rate HVPS – High Voltage Power Service.

Rate HVPS – High Voltage Power Service — **Second Revised Page No. 60**
Cancelling First Revised Page No. 60

Language has been modified from "his" to "its."

Rate AL – Architectural Lighting Service — **Second Revised Page No. 63**
Cancelling First Revised Page No. 63

Item No. 5 under the "Special Terms and Conditions" section has been removed as the Company no longer provides a separate seasonal service rate.

Rate SM – Street Lighting Municipal — **Ninth Revised Page No. 68**
Cancelling Eighth Revised Page No. 68

Language has been inserted to reflect the availability of replacement of mercury vapor lamps, fixtures or luminaries, including brackets and ballasts, beginning January 1, 2019.

Language has been inserted as to the minimum number of LED lights per customer, per order requirement and the contiguous location requirement when replacing existing lighting.

Language has been inserted as to the maximum LED light installations the Company shall be required to perform annually.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SM – Street Lighting Municipal **Ninth Revised Page No. 68**
Cancelling Eighth Revised Page No. 68

Eighth Revised Page No. 69
Cancelling Seventh Revised Page No. 69

Columns in the Monthly Rate section have been updated to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

Rate SM – Street Lighting Municipal **Eighth Revised Page No. 69**
Cancelling Seventh Revised Page No. 69

Current LED lamp wattages have been removed as obsolete.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

The last three (3) paragraphs under "Electric Charges" that resided on Seventh Revised Page No. 69, Cancelling Sixth Revised Page No. 69 in Supplement No. 91 have been moved to Fifth Revised Page No. 70, Cancelling Fourth Revised Page No. 70 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

Rate SM – Street Lighting Municipal **Fifth Revised Page No. 70**
Cancelling Fourth Revised Page No. 70

The Rate Schedule name in the header has been revised to read "Lighting."

The last three (3) paragraphs under "Electric Charges" that resided on Seventh Revised Page No. 69, Cancelling Sixth Revised Page No. 69 in Supplement No. 91 have been moved to Fifth Revised Page No. 70, Cancelling Fourth Revised Page No. 70 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

The "Special Terms and Conditions" section that resided on Fourth Revised Page No. 70, Cancelling Third Revised Page No. 70 in Supplement No. 155 has been moved to Original Page No. 70A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SM – Street Lighting Municipal.

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate SM – Street Lighting Municipal.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SM – Street Lighting Municipal **Original Page No. 70A**

Original Page No. 70A has been added in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SM – Street Lighting Municipal.

The "Special Terms and Conditions" section originally shown on Fourth Revised Page No. 70, Cancelling Third Revised Page No. 70 in Supplement No. 155 has been moved to Original Page No. 70A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SM – Street Lighting Municipal.

Item No. 5 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate SM – Street Lighting Municipal.

Rate SH – Street Lighting Highway **Ninth Revised Page No. 71**
Cancelling Eighth Revised Page No. 71

Columns in the Monthly Rate section have been updated to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

New LED lamp wattages have been inserted as choices for Cobra Head fixtures.

The first three (3) paragraphs under "Electric Charges" that resided on Eighth Revised Page No. 71, Cancelling Seventh Revised Page No. 71 in Supplement No. 155 have been moved to Third Revised Page No. 72, Cancelling Second Revised Page No. 72 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

Rate SH – Street Lighting Highway **Third Revised Page No. 72**
Cancelling Second Revised Page No. 72

The first three (3) paragraphs under "Electric Charges" that resided on Eighth Revised Page No. 71, Cancelling Seventh Revised Page No. 71 in Supplement No. 155 have been moved to Third Revised Page No. 72, Cancelling Second Revised Page No. 72 in Supplement No. 174 in order to accommodate the additional LED lamp wattages.

Rate SH – Street Lighting Highway **Third Revised Page No. 72**
Cancelling Second Revised Page No. 72

The "Special Terms and Conditions" section that resided on Second Revised Page No. 72, Cancelling First Revised Page No. 72 in Supplement No. 72 has been moved to Second Revised Page No. 73, Cancelling First Revised Page No. 73 in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate SH – Street Lighting Highway.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate SH – Street Lighting Highway — **Second Revised Page No. 73**
Cancelling First Revised Page No. 73

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate SH – Street Lighting Highway.

The "Special Terms and Conditions" section that resided on Second Revised Page No. 72, Cancelling First Revised Page No. 72 in Supplement No. 72 has been moved to Second Revised Page No. 73, Cancelling First Revised Page No. 73 in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

Language has been modified to remove "230/460 volts" in Item No. 2 under the "Special Terms and Conditions" section.

Rate SH – Street Lighting Highway — **Original Page No. 73A**

Original Page No. 73A has been added to Tariff No. 24 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

The "Special Terms and Conditions" section that resided on First Revised Page No. 73, Cancelling Original Page No. 73 in Supplement No. 2 has been moved to Original Page No. 73A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

Item No. 9 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate SH – Street Lighting Highway.

The "Term of Contract" section that resided on First Revised Page No. 73, Cancelling Original Page No. 73 in Supplement No. 2 has been moved to Original Page No. 73A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate SH – Street Lighting Highway.

Rate PAL – Private Area Lighting — **Ninth Revised Page No. 76**
Cancelling Eighth Revised Page No. 76

Columns in the Monthly Rate section have been updated and revised to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

The "Supply Charges" section that resided on Eighth Revised Page No. 76, Cancelling Seventh Revised Page No. 76 in Supplement No. 155 has been moved to Fifth Revised page No. 77, Cancelling Fourth Revised Page No. 77 in Supplement No. 174 to accommodate the new LED lamp wattages that have been added to Rate PAL – Private Area Lighting.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rate PAL – Private Area Lighting — **Fifth Revised Page No. 77**
Cancelling Fourth Revised Page No. 77

The "Supply Charges" section that resided on Eighth Revised Page No. 76, Cancelling Seventh Revised Page No. 76 in Supplement No. 155 has been moved to Fifth Revised page No. 77, Cancelling Fourth Revised Page No. 77 in Supplement No. 174 to accommodate the new LED lamp wattages that have been added to Rate PAL – Private Area Lighting.

Language has been modified to correct the reference from "UMS – Unmetered Service" to "PAL – Private Area Lighting."

Rate PAL – Private Area Lighting — **Sixth Revised Page No. 78**
Cancelling Fifth Revised Page No. 78

The "Special Terms and Conditions" section that resided on Fifth Revised Page No. 78, Cancelling Fourth Revised Page No. 78 in Supplement No. 155 has been moved to Original Page No. 78A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate PAL – Private Area Lighting.

A "Customer Owned and Maintained Equipment Charge" section has been added to Rate PAL – Private Area Lighting.

Rate PAL – Private Area Lighting — **Original Page No. 78A**

Original Page No. 78A has been added to Tariff No. 24 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate PAL – Private Area Lighting.

The "Special Terms and Conditions" section that resided on Fifth Revised Page No. 78, Cancelling Fourth Revised Page No. 78 in Supplement No. 155 has been moved to Original Page No. 78A in Supplement No. 174 to accommodate the addition of a "Customer Owned and Maintained Equipment Charge" section that has been added to Rate PAL – Private Area Lighting.

Item No. 5 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate PAL – Private Area Lighting.

Standard Contract Riders — **Seventh Revised Page No. 79A**
Rider Matrix — **Cancelling Sixth Revised Page No. 79A**

The Rider Matrix has been revised to show the removal of Rider No. 4 – Budget Billing HUD Finance Multi-Family Housing and Rider No. 7 – SECA Charge. The Riders now read "Intentionally Left Blank."

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 1 – Retail Market Enhancement Surcharge — **Nineteenth Revised Page No. 80**
Cancelling Eighteenth Revised Page No. 80

Rider No. 1 – Retail Market Enhancement Surcharge has been modified to remove the recovery of the Purchase of Receivables ("POR") program discount expense associated with the uncollectible expense of EGS consolidated billings. In accordance with Docket No. P-2016-2543140, the expense is being rolled into and recovered through base rates.

Rider No. 1 – Retail Market Enhancement Surcharge — **Nineteenth Revised Page No. 80**
Cancelling Eighteenth Revised Page No. 80

Fifth Revised Page No. 80A
Cancelling Fourth Revised Page No. 80A

In the "Calculation of Rates" section, reference to Purchase of Receivables ("POR") has been removed from the formula and the definition.

Rider No. 4 – Budget Billing HUD Financed Multi Family Housing — **Second Revised Page No. 83**
Cancelling First Revised Page No. 83

Rider No. 4 – Budget Billing HUD Financed Multi-Family Housing is being removed as obsolete.

Rider No. 5 – Universal Service Charge — **Fourteenth Revised Page No. 84**
Cancelling Thirteenth Revised Page No. 84

Rider No. 5 – Universal Service Charge — **Sixth Revised Page No. 85**
Cancelling Fifth Revised Page No. 85

Language in the "Calculation of Charge" section has been revised. This language was included in the tariff to address a prior CAP Plus proposal. The Company does not have a CAP Plus plan; therefore, it is appropriate to remove this language.

Rider No. 5 – Universal Service Charge — **Sixth Revised Page No. 85**
Cancelling Fifth Revised Page No. 85

Language in the "Calculation of Charge" section has been revised. Pursuant to the Company's 2017-2019 Universal Service and Energy Conservation Plan, customers who receive a LIHEAP grant are no longer auto-enrolled in CAP. The elimination of the Company's auto-enrollment program was approved by Commission Order entered March 23, 2017 at Docket Number M-2016-2534323.

The CAP participation level has been reset as per the provisions of Rider No. 5.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 7 – SECA Charge — **Third Revised Page No. 87**
Cancelling Second Revised Page No. 87

Rider No. 7 – SECA Charge is being removed as the charges are being recovered through the Company's Appendix A – Transmission Service Charges ("TSC").

Rider No. 8 – Default Service Supply — **Third Revised Page No. 88A-1**
Cancelling Second Revised Page No. 88A-1

A new application period is reflected in the heading and added to the chart to reflect the addition of LED lighting.

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

Rider No. 8 – Default Service Supply — **First Revised Page No. 88A-2**
Cancelling Original Page No. 88A-2

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

Rider No. 8 – Default Service Supply — **Sixth Revised Page No. 88C**
Cancelling Fifth Revised Page No. 88C

In the "Calculation of Rates" section, the Docket No. has been updated in DSSa.

Rider No. 9 – Day-Ahead Hourly Price Service — **Sixth Revised Page No. 91**
Cancelling Fifth Revised Page No. 91

Under "Fixed Retail Administrative Charge" section, the Docket No. has been updated in FRA.

Rider No. 10 – State Tax Adjustment — **Fourteenth Revised Page No. 94**
Cancelling Thirteenth Revised Page No. 94

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

CHANGES – (Continued)

Rider No. 13 – General Service Separately Metered Electric Space Heating Service — **Fifth Revised Page No. 97**
Cancelling Fourth Revised Page No. 97

The word "metered" has been removed in the paragraph under "Energy Charges."

Rider No. 16 – Service to Non-Utility Generating Facilities — **Sixth Revised Page No.101**
Cancelling Fifth Revised Page No. 101

Sixth Revised Page No.102
Cancelling Fifth Revised Page No. 102

Language has been revised and inserted to clarify the service being provided and the definition of billing determinates.

Rider No. 20 – Smart Meter Charge — **Thirty-Seventh Revised Page No. 108**
Cancelling Thirty-Sixth Revised Page No. 108

Rider No. 20 – Smart Meter Charge has been modified to reflect that it has been set to zero.

Rider No. 21 – Net Metering Service — **Fourth Revised Page No. 110**
Cancelling Third Revised Page No. 110

Language has been revised and inserted to require the installation of a generation meter to measure actual customer-generator facility output to accommodate and plan for increased saturation of net metered installations.

Rider No. 22 – Distribution System Improvement Charge — **Seventh Revised Page No. 112B**
Cancelling Sixth Revised Page No. 112B

Rider No. 22 – Distribution System Improvement Charge ("DSIC") has been modified to reflect that it has been set to zero.

Appendix A – Transmission Service Charges — **Eleventh Revised Page No. 114**
Cancelling Tenth Revised Page No. 114

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES

Rate RS – Residential Service	Ninth Revised Page No. 32
	Cancelling Eighth Revised Page No. 32
Rate RH – Residential Service Heating	Ninth Revised Page No. 34
	Cancelling Eighth Revised Page No. 34
Rate RA – Residential Service Add-On Heat Pump	Ninth Revised Page No. 37
	Cancelling Eighth Revised Page No. 37
Rate GS/GM – General Service Small and Medium	Eighth Revised Page No. 40
	Cancelling Seventh Revised Page No. 40
Rate GMH – General Service Medium Heating	Eighth Revised Page No. 43
	Cancelling Seventh Revised Page No. 43
Rate GMH – General Service Medium Heating	Eighth Revised Page No. 45
	Cancelling Seventh Revised Page No. 45
Rate GL – General Service Large	Eighth Revised Page No. 47
	Cancelling Seventh Revised Page No. 47
Rate GLH – General Service Large Heating	Eighth Revised Page No. 50
	Cancelling Seventh Revised Page No. 50
Rate GLH – General Service Large Heating	Fifth Revised Page No. 51
	Cancelling Fourth Revised Page No. 51
Rate L – Large Power Service	Eighth Revised Page No. 53
	Cancelling Seventh Revised Page No. 53
Rate AL – Architectural Lighting Service	Ninth Revised Page No. 61
	Cancelling Eighth Revised Page No. 61
Rate SE – Street Lighting Energy	Ninth Revised Page No. 64
	Cancelling Eighth Revised Page No. 64
Rate SM – Street Lighting Municipal	Ninth Revised Page No. 68
	Cancelling Eighth Revised Page No. 68
Rate SM – Street Lighting Municipal	Fifth Revised Page No. 70
	Cancelling Fourth Revised Page No. 70
Rate SH – Street Lighting Highway	Ninth Revised Page No. 71
	Cancelling Eighth Revised Page No. 71
Rate PAL – Private Area Lighting	Ninth Revised Page No. 76
	Cancelling Eighth Revised Page No. 76

LIST OF MODIFICATIONS MADE BY THIS TARIFF

INCREASES – (Continued)

Rate PAL – Private Area Lighting	Sixth Revised Page No. 78 Cancelling Fifth Revised Page No. 78
Rider No. 10 – State Tax Adjustment	Fourteenth Revised Page No. 94 Cancelling Thirteenth Revised Page No. 94
Rider No. 16 – Service to Non-Utility Generating Facilities	Sixth Revised Page No.102 Cancelling Fifth Revised Page No. 102

Unit prices have changed, resulting in increases.

DECREASES

Rate HVPS – High Voltage Power Service	Eighth Revised Page No. 57 Cancelling Seventh Revised Page No. 57
Rate UMS – Unmetered Service	Ninth Revised Page No. 74 Cancelling Eighth Revised Page No. 74
Rate PAL – Private Area Lighting	Ninth Revised Page No. 76 Cancelling Eighth Revised Page No. 76
Rider No. 1 – Retail Market Enhancement Surcharge	Nineteenth Revised Page No. 80 Cancelling Eighteenth Revised Page No. 80
Rider No. 20 – Smart Meter Charge	Thirty-Seventh Revised Page No. 108 Cancelling Thirty-Sixth Revised Page No. 108
Rider No. 22 – Distribution System Improvement Charge	Seventh Revised Page No. 112B Cancelling Sixth Revised Page No. 112B

Unit prices have changed, resulting in decreases.

TABLE OF CONTENTS

(C) – Indicates Change

RULES AND REGULATIONS

THE ELECTRIC SERVICE TARIFF

1. **FILING AND POSTING** A copy of the Tariff, comprising of the Rules and Regulations, Rates and Riders, and governing electric service, is filed with the Pennsylvania Public Utility Commission. A copy of the Tariff may be obtained by calling, e-mailing or writing the Company's business office. The Tariff may also be accessed at www.duquesnelight.com and is posted and open to inspection at the offices of the Company where payments are made by customers.

2. **REVISIONS** The tariff is subject to such change and modification as may be made from time to time in the manner prescribed by the Public Utility Law. If any rate for electric service is increased, the affected customer shall have the option of discontinuing service, but shall be obligated to pay the increased rate from the effective date thereof until service has been discontinued.

2.1 **RULES AND REGULATIONS** The Rules and Regulations, filed as part of this Tariff, are a part of every contract for service made by the Company and govern all classes of service where applicable. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service. (C)

2.2 **STATEMENT BY AGENTS** No representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto. (C)

3. **APPLICATION** Rates of the tariff apply only to the Company's Standard Service delivered from overhead supply lines except in certain restricted areas where the Company is required to provide underground distribution. Riders of the tariff amend or modify the terms governing the electric service under the rates to which they apply. Beginning January 1, 2019, Standard Service is alternating current of sixty cycles frequency, conforming as to voltage and phase with the following list of standard nominal service delivery voltages. (C)

SINGLE-PHASE	THREE-PHASE		
120/240 volts, 3 wire	120/208 volts, 4 wire	23,000 volts, 3 wire	
480 volts, 2 wire	277/480 volts, 4 wire	13,200/23,000 volts, 4 wire	(C)
13,200 volts, 2 wire	2,400 volts, 3 wire	138,000 volts, 3 wire	(C)
	2,400/4,160 volts, 4 wire		

For service installations completed prior to January 1, 2019, Standard Service may include the delivery voltages listed above as well as the following list of standard nominal service delivery voltages, as applicable. (C)

SINGLE-PHASE	THREE-PHASE
120 volts, 2 wire	230 volts, 3 wire
120/208 volts, 3 wire	460 volts, 3 wire
230 volts, 2 wire	11,500 volts, 3 wire
460 volts, 2 wire	69,000 volts, 3 wire
230/460 volts, 3 wire	345,000 volts, 3 wire
2,400 volts, 2 wire	
23,000 volts, 2 wire	

(C)

The supply of electricity may be provided by the Company or by an alternative Electric Generation Supplier ("EGS"). Rates for the supply of electricity shall apply per applicable tariffs of the Company or the EGS.

(C)

RULES AND REGULATIONS - (Continued)

THE ELECTRIC SERVICE TARIFF - (Continued)

3.1 DEFINITIONS (C)

(1) Aggregator or Market Aggregator – An entity, licensed by the Commission, which purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers. (C)

(2) Applicant – A natural person not currently receiving service who applies for residential service provided by a public utility or any adult occupant whose name appears on the mortgage, deed or lease of the property for which the residential utility service is requested. The term does not include a person who, within thirty (30) days after service termination or discontinuance of service, seeks to have service reconnected at the same location or transferred to another location within the service territory of the Company. (C)

(3) Basic Services – The services necessary for the physical delivery of electricity service such as supply, including default service, transmission and distribution. Unless directed otherwise, "electric service" or "service" used throughout this tariff have the same meaning.

(4) Bill Ready – A form of consolidated billing where Duquesne Light provides a customer's usage to its electric generation supplier ("EGS") and the EGS then calculates the customer's charges and sends the line item(s) back to the Company to be presented on the supplier portion of the bill.

(5) Broker or Marketer – An entity, licensed by the Commission, which acts as an agent or intermediary in the sale and purchase of electric energy but does not take title to electric energy.

(6) Commission – The Pennsylvania Public Utility Commission.

(7) Company - Duquesne Light Company.

(8) Customer – ~~A retail electric customer or potential customer of retail electricity service who are direct purchasers of electric power for use at their facility.~~ Any person, partnership, association, corporation or other legal entity lawfully receiving service from the Company. Unless indicated otherwise, "retail customer" and "customer" used throughout this tariff shall have the same meaning. A residential customer is a natural person in whose name a residential service account is listed and who is primarily responsible for payment of bills rendered for the service or any adult occupant whose name appears on the mortgage, deed or lease of the property of which the residential utility service is requested. The term includes a person who, within thirty (30) days after service termination or discontinuance of service, seeks to have service reconnected at the same location or transferred to another location within the service territory of the public utility. (C)

(9) Default Service – The Company will provide electricity to the customer in the event that a customer: 1) elects not to obtain electricity from an EGS; 2) elects to have the Company supply electricity after having previously purchased electricity from an EGS; 3) contracts with an EGS who fails to supply electricity, or 4) has been returned to Default Service by the EGS under circumstances as described in Rule No. 45.2 of this tariff.

(10) Direct access – The right of EGSs and retail customers to utilize and interconnect with the electric transmission and distribution system of the Company on a non-discriminatory basis at rates and terms and conditions of service comparable to the Companies' own use of the system to transport electricity from any generator of electricity to any retail customer.

(11) Distribution Charges – Basic service charges for delivering electricity over a distribution system (e.g. wires, transformers, substations and other equipment) to the home or business from the transmission system. The distribution charge is regulated by the Commission. These charges include basic service under 52 Pa. Code §56.15 (4) (relating to billing information) and Riders, as applicable.

(12) Electric Distribution Company ("EDC") – An entity, including Duquesne Light Company ("Company"), owning and providing facilities for the jurisdictional transmission and distribution of electricity to retail customers, except building or facility owners or operators that manage the internal distribution system serving such building or facility and that supply electric power and other related electric power services to occupants of the building or facility.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

THE ELECTRIC SERVICE TARIFF - (Continued)

3.1 DEFINITIONS - (Continued)

(13) Electric Generation Suppliers ("EGS") – A person or corporation, including municipal corporation, which provides service outside its municipal limits except to the extent provided prior to January 1, 1997. This includes brokers and marketers, aggregators or any other entities that sell to end-use customers electricity or related services utilizing the jurisdictional transmission or distribution facilities of an electric distribution company. The term excludes building or facility owner/operators that manage the internal distribution system for the building or facility and that supply electric power and other related power services to occupants of the building or facility. The term also excludes electric cooperative corporations except as provided in 15 Pa. C.S. Ch. 74 (relating to generation choice for customers of electric cooperatives).

(14) Electricity Provider - The term refers collectively to the EDC, EGS, electricity supplier, marketer, aggregator and/or broker, as well as any third party acting on behalf of these entities.

(15) Non-Basic Services - Optional recurring services which are distinctly separate and clearly not required for the physical delivery of electric service.

~~**(16) Rate Ready** – A form of consolidated billing where Duquesne Light calculates the charge to be presented on the supplier portion of the bill based upon the rates previously supplied by the electric generation supplier ("EGS").~~

~~**(17) Renewable Resource** - Includes technologies such as solar photovoltaic energy, solar thermal energy, wind power, low-head hydropower, geothermal energy, landfill or other biomass-based methane gas, mine-based methane gas, energy from waste and sustainable biomass energy.~~

~~(18)~~**(16) PJM** – PJM Interconnection, L.L.C.

(17) PJM Tariff - The PJM Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission ("FERC") and which sets forth the rates, terms and conditions of transmission service over transmission facilities located in the PJM Control Area. (C) (C)

(18) Rate Ready – A form of consolidated billing where Duquesne Light calculates the charge to be presented on the supplier portion of the bill based upon the rates previously supplied by the electric generation supplier ("EGS"). (C)

(19) Renewable Resource - Includes technologies such as solar photovoltaic energy, solar thermal energy, wind power, low-head hydropower, geothermal energy, landfill or other biomass-based methane gas, mine-based methane gas, energy from waste and sustainable biomass energy. (C)

~~(19)~~**(20) Summary Bill** - An aggregate bill prepared for two or more meter locations owned or legally controlled by the same customer for charges for electric service. (C)

~~(20)~~**(21) Supply Charges** - Basic service charges for acquiring or producing electricity for supply to retail customers. This excludes charges for transmission or other charges related to electric service. (C)

~~(21)~~**(22) Transmission Charges** - Basic charges for the cost of transporting electricity over high voltage wires from the generator to the distribution system of the Company billed to customers that acquire their electricity from the Company. Customers who choose to acquire electricity from an EGS will be billed for transmission services by the EGS. (C)

3.2 ELECTRIC GENERATION SUPPLIER TARIFF The rules and guidelines provided in the Company's "Electric Generation Supplier Coordination Tariff" (Supplier Tariff) shall apply to EGS's accessing the Company's transmission and distribution systems to supply electricity to retail customers. Those rules and guidelines pertaining to direct access procedures shall apply accordingly to customers who elect to purchase part or all of their electricity from an EGS. Copies of these rules may be obtained by calling, e-mailing or writing the Company's business office. In addition, they may also be accessed at www.duquesnelight.com and are posted and open to inspection at the offices of the Company where payments are made by customers.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS

4. CONTRACTS The Company reserves the right to require non-residential customers to sign a written contract indicating the rate for electric service and to require a contract term which, in the judgment of the Company, is sufficient to justify the cost of any facilities installed for the exclusive use of the customer and to compensate the Company for other incremental costs of Nonstandard Service. Customers who have facilities extended for their exclusive use will be permitted to purchase electricity from an EGS according to the provisions of direct access and 66 Pa.C.S. § 2807. Extension of such facilities will not be conditioned on the customer's agreement to purchase supply from the Company. Receipt of electric service by any entity, however, shall constitute the receiver a customer of the Company, subject to its rules and regulations, whether service is based upon contract, agreement, accepted signed application or otherwise. The customer shall notify the Company, in advance of receipt of electric service, of the customer's name, address to which the electricity is to be delivered, the address to which the bill is to be mailed, the date delivery of electricity is to commence, and provide information requested by the Company regarding the customer's credit standing. The customer shall notify the Company to cancel electric service and the customer shall be responsible for payment for all electric charges until the customer has so notified the Company to cancel electric service. (C)

The Company at its sole discretion may enter into special contracts for electric service with industrial or commercial customers ~~having load of at least 100 kW~~ to address changing business needs, ~~or~~ operating conditions~~, for incremental sales of at least 100 kW from existing or new industrial customers,~~ or ~~to address~~ less expensive competitive alternatives for energy ~~to be used for applications other than space heating~~. If requested by the Company, the customer shall provide to the Company, on a confidential basis, all information, records and financial analysis necessary to evaluate the customer's request for a special contract. (C) (C) (C)

Terms and conditions of service will be mutually agreed upon by the Company and the customer and included in a signed contract, which will be filed with the Public Utility Commission. The Company at its sole discretion may request Public Utility Commission approval. The terms of the agreement will be confidential upon filing with the Commission. Rates established under special contracts will be sufficient to recover, at a minimum, all appropriate incremental costs. Any special contracts written to become effective on or after January 1, 2007, shall apply only to charges for the distribution service provided by the Company.

The contract shall contain all terms and conditions and the rates and charges to be paid for electric service.

The contract shall be for a period of no less than ~~five (5) years~~one (1) year and no greater than ten (10) years. (C)

The contract will be terminated by the Company if the Company charges are not paid when due as specified in Tariff Rule No. 21, before the addition of the Late Payment Charge. Upon termination of the contract under these conditions, the regular electric tariff rates will be applied to electric service rendered from that point forward. A new special contract will not be made available to a customer whose previous special contract was terminated because of failure to pay bills as specified in Tariff Rule No. 21.

(C)

For contracts that contain provisions governing the customer's rights under direct access, the Company will unbundle the customer's contract and the customer will be eligible to obtain electricity from an EGS only in accordance with the terms and conditions of the customer's contract. Upon expiration of their contract, special contract customers will default to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

(C) – Indicates Change

~~RULES AND REGULATIONS - (Continued)~~

~~THE ELECTRIC SERVICE TARIFF - (Continued)~~

~~CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS~~

~~4. CONTRACTS – (Continued)~~ ~~(C)~~

~~For contracts that contain provisions governing the customer's rights under direct access, the Company will unbundle the customer's contract and the customer will be eligible to obtain electricity from an EGS only in accordance with the terms and conditions of the customer's contract. Upon expiration of their contract, special contract customers will default to Rider No. 9 - Hourly Price Service.~~

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

5. **DEPOSITS AND ADVANCE PAYMENTS** The Company reserves the right to require a cash deposit from applicants taking service for a period of less than thirty (30) days, in an amount equal to the estimated gross bill for Company charges, including applicable EGS charges, for such temporary service. The gross bill for Company charges shall include all fixed, demand and energy charges for Company charges in accordance with the applicable tariff. Deposits may be required from all other applicants when creditworthiness has not been established. A deposit may also be required from existing customers when such customer's credit standing is impaired by delinquent payments of any two (2) consecutive electric bills for Company charges or three (3) or more electric bills for Company charges within the preceding twelve (12) months, or as a condition to the reconnection of service or failure to comply with a payment arrangement. Company charges include the customer's EGS receivables that are purchased by the Company. The Company shall not require an applicant or customer who is confirmed to be eligible for a customer assistance program to provide a cash deposit. (C)

The Company, at its discretion, may deem a non-residential customer or applicant to be not creditworthy. Evidence that such a customer or applicant is not creditworthy may include, but shall not be limited to, where the customer or applicant: (i) is insolvent (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due); (ii) has a class of publicly-traded debt outstanding that is rated to be below investment grade; (iii) has tendered two (2) or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. § 3502, within the last twelve (12) billing cycles; or (iv) has had an account balance at least sixty (60) days in arrears within the last twelve (12) billing cycles. The Company may require non-residential customers or applicants to provide financial data as reasonably necessary for the Company to assess their creditworthiness. (C)

The Company may also use an applicant or customer credit score from a third party credit agency as a means to establish creditworthiness. The credit score in the report will be based in part on previous utility billing history and will use a commercially recognized credit scoring methodology that is within the range of generally accepted industry practices to determine whether security or advance payments are required to establish service. The Company may request a government issued photo ID of any applicant to verify the application.

Where the Company requires a deposit, t~~T~~he amount of the deposit will be based on Company charges in an amount that is equal to one-sixth of the applicant's estimated annual bill or one-sixth of the actual average annual bill for existing customers at the premises, provided that the minimum deposit amount for non-residential customers shall be $250.00. In accordance with Commission regulations, the deposit shall be payable during the 90-day period commencing when the Company determines a deposit is required whether for new service or for deposits required upon reconnection of service as described in Rule No. 40. Failure to pay a required deposit within the time period noted above may result in termination of service consistent with Commission regulations. An applicant or existing customer may furnish a third party guarantor in lieu of a cash deposit, with the provision of a written guaranty setting forth the terms therein. The guarantor will be responsible for all missed payments of the applicant or customer. (C) (C)

The Company will pay interest on residential cash deposits computed at the simple annual interest rate determined by the Commonwealth of Pennsylvania's Secretary of Revenue. The interest rate in effect when the deposit is required to be paid shall remain in effect until the later of the date the deposit is refunded or credited or December 31. On January 1 of each year, the new interest rate for that year will apply to the deposit. For all other cash deposits, the Company will pay interest at the lower of the average of 1-year Treasury Bills for September, October and November of the previous year beginning May 1, 1995 and January 1, 1996 and each year thereafter, or six percent per annum without deduction for any taxes thereon, provided that interest accrued prior to April 14, 1995 shall be calculated at 6%. On deposits held for more than one year, accrued interest will be paid at the end of each anniversary year. Upon the return of a deposit, any unpaid interest accrued thereon will be paid.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

CONTRACTS, DEPOSITS AND ADVANCE PAYMENTS - (Continued)

5. DEPOSITS AND ADVANCE PAYMENTS - (Continued)

Deposits secured from a residential applicant or customer shall be returned to the depositor when a timely payment history has been established. A timely payment history is established when a customer has paid undisputed bills in full and on time for twelve (12) consecutive months. Should a customer become delinquent prior to establishing a timely payment history, the Company may deduct the outstanding balance from the deposit. Deposits secured from other than residential customers shall be returned to the depositor upon annual review provided such depositor shall have paid undisputed bills during those consecutive twelve (12) months without having service terminated and without having paid the bill subsequent to the due date so long as the customer is not currently delinquent. Payment of any disputed bill, where the payment is withheld beyond the due date set forth on the face of the bill at issue and the dispute over which is terminated substantially in favor of the customer, shall be made by the customer within fifteen (15) days following the termination of that dispute in order to be deemed timely. Where service is discontinued, the deposit and unpaid interest accrued thereon to the date of discontinuance of service, less the amount of all bills due the Company, will promptly be paid to the customer.

~~The Company reserves the right to require payment in advance for seasonal service, when the applicants elect to take such service, in an amount equal to the estimated gross Company charges for such seasonal service as determined by the provisions of the rate under which this service is taken.~~ (C)

For purposes of all of the provisions of this Rule No. 5, when a customer resides at a place of business or commercial establishment, legitimately served pursuant to a commercial or industrial rate schedule, that is not a residential dwelling unit attached thereto, the customer is not thereby entitled to any of the protections in the Pennsylvania Public Utility Code or the Commission's regulations implementing the Pennsylvania Public Utility Code, or to any of the provisions of these rules or this Tariff, that apply exclusively to deposits for residential customers. (C)

PAYMENT OF OUTSTANDING BALANCE

5a. PAYMENT OF OUTSTANDING BALANCE As a condition of the furnishing of service to an applicant or customer, the payment of any outstanding account amount with the Company for which the applicant or customer is legally responsible is required. The Company may require the payment of an outstanding balance or portion of an outstanding balance as a condition of furnishing service if the applicant or customer resided at the property ~~for which service is requested~~ during the time the outstanding balance accrued and for the time applicant/customer resided there, not exceeding four (4) years from the date that the last bill rendered, except for fraud or theft. The Company may require the applicant or customer to provide, and may establish that an applicant or customer previously resided at a property for which residential service is requested through the use of a mortgage, deed or lease or a commercially available consumer credit reporting service. In addition, the Company may also require and use ~~a~~ valid ~~driver's license~~government-issued photo identification, and may use billing/mailing records, court records, factual reporting and Company records where the applicant or customer was listed as a spouse or an occupant of a premise, such as on a customer assistance program enrollment form, a payment arrangement, a power of attorney or authorization or a medical certification. (C) (C) (C) (C) (C) (C) (C)

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE

6. INSTALLATION RULES Except for Nonstandard Service expressly approved in advance by the Company, ~~S~~service installations shall be made in accordance with the Company's "Electric Service Installation Rules," copies of which may be obtained by calling, e-mailing or writing the Company's business office. In addition, the Rules may be accessed at www.duquesnelight.com. (C)

6.1 SERVICE POINT The Service Point for the customer's service installation shall depend on the customer's type of service. The Service Point shall generally be designated as follows: (C)

Type of Service	Service Point
Service voltage greater than 600V	Metering terminals, or for transformed service, secondary transformer terminals
Overhead service at voltage less than 600V	Service drop
Underground service at voltage less than 600V	For underground service from overhead secondary lines: the service lateral connection to Company pole. For underground service from underground spot networks: the network protector spade(s). For underground service from street secondary underground networks: the collector bus. For three-phase transformed underground service: the secondary transformer terminal. In Underground Residential Developments covered by Rule No. 13.2: the meter base. For other underground service from underground secondary lines: the terminal box.
Any service via lines supported by a customer-owned pole or structure	Point of service line connection to the first customer-owned pole or structure to which Company facilities connect

The Company reserves the right to designate an alternative Service Point, at its sole discretion, for customers with atypical or specialized service configurations, or customers participating in the Company's EV ChargeUp pilot program for electric vehicle charging stations.

The Company shall not be required to install or maintain any conductors, meter base, equipment or apparatus except meter and meter accessories, as applicable, beyond the Service Point.

RULES AND REGULATIONS - (Continued) (C)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS

A. Definitions

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

(1) **Contractor cost -** The amount paid to a contractor for work performed on a line extension.

(2) **Direct labor cost -** The pay and expenses of public utility employees directly attributable to work performed on line extensions, but does not include construction overheads or payroll taxes, workers' compensation expenses, or similar expenses.

(3) **Direct material cost -** The purchase price of materials used for a line extension, but does not include the related stores expenses. In computing direct material costs, proper allowance should be made for unused materials recovered from temporary structures, and discounts allowed and realized in the purchase of materials.

(4) **Total construction cost -** The contractor cost, direct labor cost, direct material cost, stores expense, construction overheads, payroll taxes, workers' compensation expenses, or similar expenses.

(5) **Current Year -** For purposes of calculating a revenue guarantee, current year shall be each consecutive period of twelve (12) calendar months following the date permanent electric delivery service was first provided to a customer.

(6) **Income Tax -** Federal and State tax relating to the tax liability of contributions in aid-of-construction ("CIAC").

B. Overhead Areas

(1) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all single-phase overhead supply lines operating at 23,000 volts or less to approximately 100 feet within the customer's property line without a guarantee of revenue. (C)

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

B. Overhead Areas - (Continued)

(2) In areas where the existing supply lines are overhead, the Company will construct and maintain extensions of all three-phase overhead supply lines, operating at 23,000 volts or less, which are usable as a part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer over a period of five years which is sufficient to recover the actual total construction cost of the three-phase overhead line extension, less the estimated total construction cost for an equivalent single-phase overhead line extension. In the event that a revenue guarantee is not sufficient to recover the estimated total cost of the construction, or if the Company determines that the extension is speculative, or the customer represents a credit risk, the Company may require an up-front contribution in aid of construction (CIAC) from the customer to recover the total cost of construction. A customer may choose the option to make a CIAC rather than utilize a revenue guarantee. The Company will consider financing alternatives, such as a letter of credit or other payment arrangements, in lieu of a CIAC when appropriate. Any additional CIAC payment required will include the related income tax.

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

C. Underground Areas

(1) In areas where the existing supply lines are underground outside the limits of a residential development covered by Tariff Rule 13.2, the Company will construct and maintain extensions of all single-phase underground supply lines operating at 23,000 volts or less which are usable as part of its general supply system without a guarantee of revenue. When the single-phase supply line extension is to supply electricity exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer, over a period of five years which is sufficient to recover the actual total contractor cost, direct labor cost and direct material cost for the full length of the single-phase underground line extension, less the estimated total contractor cost, direct labor cost, and direct material cost for an equivalent single-phase overhead line extension. In the event that a revenue guarantee is not sufficient to recover the estimated total cost of the construction, or if the Company determines that the extension is speculative, or the customer represents a credit risk, the Company may require an up-front contribution in

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

C. Underground Areas - (Continued)

aid of construction (CIAC) from the customer to recover the total cost of construction. A customer may choose the option to make a CIAC rather than utilize a revenue guarantee. The Company will consider financing alternatives, such as a letter of credit or other payment arrangements, in lieu of a CIAC when appropriate. Any additional CIAC payment required will include the related income tax.

(2) In areas where the existing supply lines are underground outside of the limits of a residential development covered by Tariff Rule 13.2, the Company will construct and maintain extensions of all three-phase underground supply lines operating at 23,000 volts or less which are usable as part of its general supply system without a guarantee of revenue. When the three-phase supply line extension is to supply service exclusively to a single customer, such a supply line will be extended to the customer's property line only if a guarantee of revenue is provided by the customer over a period of five years which is sufficient to recover the actual total construction cost of the three-phase underground line extension, less the estimated total construction cost for an equivalent single-phase overhead line extension. In the event that a revenue guarantee is not sufficient to recover the estimated total cost of the construction, or if the Company determines that the extension is speculative, or the customer represents a credit risk, the Company may require an up-front contribution in aid of construction (CIAC) from the customer to recover the total cost of construction. A customer may choose the option to make a CIAC rather than utilize a revenue guarantee. The Company will consider financing alternatives, such as a letter of credit or other payment arrangements, in lieu of a CIAC when appropriate. Any additional CIAC payment required will include the related income tax.

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

D. Rights-of-Way

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

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

7. SUPPLY LINE EXTENSIONS - (Continued)

E. Revenue Guarantees

The revenue guarantee amount shall be the estimated combined cost of (i) the line extension and (ii) other new Company facilities necessary to serve the customer. The annual revenue guarantee amount shall be the revenue guarantee amount, divided by the number of years in the guarantee period. The annual revenue guarantee amount will be reviewed yearly and will be adjusted to the minimum charges as provided in the applicable rate schedule on the following basis: (C) (C)

(1) When the total of the monthly Company delivery charges at the end of the current year is less than the annual revenue guarantee amount, a payment equal to the difference plus the related income tax where applicable shall be immediately due and payable.

(2) When the total of the monthly Company delivery charges within the number of years in the guarantee period~~,~~ equals or exceeds the revenue guarantee amount, no further payments toward the revenue guarantee amount are required. Any prior payments in excess of the revenue guarantee amount, except for otherwise-applicable charges for electric service, will be refunded with accrued interest. (C) (C)

(3) If an additional customer is served from the line extension, the revenue guarantee amount will be reduced to the cost of the line extension which is used exclusively to serve the single customer. If the cost of the line extension to serve the new customer would increase the revenue guarantee amount for an existing customer, the extension shall be considered as a new line extension.

(4) In the event the customer discontinues or cancels service before the end of the guarantee period, the balance of the revenue guarantee amount plus the related income tax where applicable shall be immediately due and payable.

F. Contributions in Aid of Construction

The Contribution in Aid of Construction (CIAC) will be refunded to the customer over the five-year revenue guarantee period to the extent that the revenue from the customer satisfies the revenue guarantee.

(1) When the total of the monthly Company delivery charges at the end of the current year is greater than or equal to one-fifth of the CIAC, a refund of one-fifth of the CIAC will be made to the customer.

(2) When the total of the monthly Company delivery charges at the end of the current year is less than one-fifth of the CIAC, a refund of one-fifth of the CIAC less the revenue shortfall will be made to the customer.

(3) At the end of the five-year revenue guarantee period, a final reconciliation of delivery charges during the period will be made against the CIAC. If the total delivery charges paid exceed or equal the original CIAC, any remaining CIAC will be returned to the customer. If the total delivery charges paid are less than the original CIAC, the remaining CIAC will be retained by the Company.

RULES AND REGULATIONS - (Continued)

INSTALLATION OF SERVICE - (Continued)

8. ~~CONNECTION CHARGES~~NONSTANDARD SERVICE The Company reserves the right to ~~make~~ require a customer or applicant for service to pay the cost, ~~reasonable charge~~ including the related income tax, ~~payable in advance,~~of any special installation necessary to meet the unusual requirements of the customer or applicant for service, including, but not limited to: (C) (C) (C) (C)

(1) service at other than standard voltages, (C)

(2) service for intermittent, unbalanced or fluctuating loads, which, in the Company's sole judgement, would not generate sufficient revenue to recover the installation costs of the required facilities, (C)

(3) service for loads that will be continuous but that will generate minimal usage, and which, in the Company's sole judgement, would not generate sufficient revenue to recover the installation costs of the required facilities, (C)

(4) service for loads that will require provision of closer voltage regulation than required by standard service, (C)

(5) redundant service requested by the customer and not required by the Company, and (C)

(6) service routings or configurations that deviate from the Company's standard construction ~~lines and for equipment installed for the exclusive use of a customer which exceed Company established~~ standards described in the Company's "Electric Service Installation Rules~~,.~~" or that would otherwise necessitate significant construction of new Company facilities. (C) (C) (C)

The customer or applicant shall pay all costs to the Company of performing environmental assessments, including, but not limited to, the cost of consultants utilized by the Company, the cost of removal and disposal of contamination, waste or hazardous materials or dealing with other adverse environmental conditions associated with either the initial installation, modification, repair, maintenance or removal of service facilities. (C)

The Company may decline to provide Nonstandard Service where, in the Company's sole judgment, it would not be commercially, operationally, and/or technically reasonable to provide such service. (C)

9. RELOCATIONS OF FACILITIES

A. Pole Removal or Relocation for Residential Customers

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

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

(1) Contractor costs - Amount paid by the utility to a contractor for work performed on a pole removal or relocation.

(C)

INSTALLATION OF SERVICE - (Continued)

9. RELOCATIONS OF FACILITIES – (Continued)

A. Pole Removal or Relocation for Residential Customers – (Continued)

(2) **Direct labor costs** - Includes pay and expenses of public utility employees directly attributable to work performed on pole removals or relocations. Excludes payroll taxes, workmen's compensation, similar items of expense and construction overhead costs.

(3) **Direct materials costs** - Includes the purchase price of materials used in performing a pole removal or relocation and excludes the related stores expenses. Proper allowance shall be made for unused materials, and materials recovered from temporary structures, and for discounts allowed and realized in purchase of materials.

(4) **Income tax** - Federal and State tax relating to the tax liability of contributions in aid-of-construction.

B. Other Company Facilities for all Customers

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

RULES AND REGULATIONS - (Continued)

MEASUREMENT AND USE OF SERVICE - (Continued)

14.2 CUSTOMER REQUEST FOR SPECIAL METERING – (Continued)

The Company has adopted a program that provides all customers with meters to provide data for normal monthly billing services. In the event that a residential or small commercial customer, or an EGS on behalf of a residential or small commercial customer, requests an upgrade to an Alpha Powerplus meter, which the Company provides for large commercial and industrial customers, installation of that meter will be provided at a cost of $586.00, plus additional costs for the appropriate communication/system infrastructure. These net incremental charges, as set forth in the Company's Advance Meter Catalog, may be paid to the Company by either the customer or the EGS, or jointly by the customer and the EGS pursuant to a mutual agreement.

~~Act 129 of 2008 ("Act") required electric distribution companies ("EDCs") with at least 100,000 customers to file a Smart Meter Procurement and Installation Plan ("Plan") for Commission approval. The Commission's Smart Meter Procurement and Installation Implementation Order entered June 24, 2009, at Docket No. M-2009-2092655 set forth additional details for EDCs and rules for customers who request a smart meter prior to the EDC installing a smart meter on their premise. For customers who request a smart meter installed at their premise prior to October 2012, the Company will install an interval meter in lieu of a smart meter. The meter will be provided at a cost of $586.00, as specified above, plus $719.00 for the appropriate communication/system infrastructure. For a customer requesting pulse data from the interval meter, an additional charge of $197.00 will apply. The requesting customer's account must be current and all payments must be made up-front prior to installation.~~ (C)

~~**14.3 SUB-METERING** If a customer wishes to have metering installed in addition to the Company installed meter, the meter must be installed on the customers electrical system and at the expense of the customer.~~ (C)

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

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

16. USE OF SERVICE BY CUSTOMER The customer shall use the electric service only at the premise where service is established; and after electric service has been established, shall notify the Company of any change in connected load, demand, or other conditions of use. The customer shall notify the Company of other on site sources of electric generation or electricity concurrently produced as a by-product of another process or electricity produced utilizing renewable resources. Customers who own and operate electric generation equipment shall conform with the Company's "Electric Service Installation Rules," copies of which may be obtained by calling, e-mailing or writing the Company's business office or at www.duquesnelight.com. For customers who own and operate electric generation, the provisions of Rider No. 16 - Service to Non-Utility Generating Facilities and Rider No. 21 - Net Metering Service may also apply.

RULES AND REGULATIONS - (Continued)

MEASUREMENT AND USE OF SERVICE - (Continued)

18. REDISTRIBUTION All electric energy shall be consumed by the customer to whom the Company supplies and delivers such energy, except that (1) ~~a~~ the customer owning and operating a separate office building, and (2) any other customer who, upon showing that special circumstances exist, obtains the written consent of the Company may redistribute electric energy to tenants of such customer, but only if such tenants are not required to make a specific payment for such energy.~~, except where such payments would encourage energy conservation.~~ (C) (C)

This Rule shall not affect any practice undertaken prior to June 1, 1965. See Rule No. 41 for special requirements for residential dwelling units in a building.

18.1 ELECTRIC VEHICLE CHARGING For purposes of third party-owned electric vehicle charging stations, charging the electric vehicle shall not be considered redistribution as defined in Rule No. 18 - Redistribution. Electric vehicles are defined as any vehicle licensed to operate on public roadways that are propelled in whole or in part by electrical energy stored on-board for the purpose of propulsion. Types of electric vehicles include, but are not limited to, plug-in hybrid electric vehicles and battery electric vehicles. Electric vehicle charging stations shall be made in accordance with the Company's "Electric Service Installation Rules," a copy of which may be found at www.duquesnelight.com. The station must be designed to protect for back flow of electricity to the Company's electrical distribution circuit as required by Company rules. The Company shall not be liable for any damages associated with operation of the charging station. For stations dedicated solely for the purpose of charging electric vehicles wherein a third party owns the charger and allows an electric vehicle owner to use their facility to charge an electric vehicle, the owner of the charging facility shall notify the Company at least one hundred twenty (120) days in advance of the planned installation date and may be required to install metering for the station as determined by the Company. The third party owner of the station shall be responsible for all applicable Tariff rates, fees and charges. For such installations, the electric vehicle owner shall be responsible for all fees imposed by the owner of the station for charging the electric vehicle.

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

BILLS AND NET PAYMENT PERIODS

20. BILLING The Company will render a bill monthly for electric service.

20.1 BILLING OPTIONS Customers who elect to purchase their electricity from an Electric Generation Supplier ("EGS") may choose: (1) Consolidated Billing and receive a single bill from the Company that includes Company charges and EGS charges; or (2) Separate Billing and receive one bill from the Company for Company charges and a second bill from the EGS for EGS charges. The customer's billing option will be communicated to the Company by the EGS, in accordance with the provisions contained in the Company's Supplier Tariff.

20.2 SUMMARY BILLING The Company may, at its discretion and upon customer request, provide Summary Bills in lieu of individual bills to qualifying customers. Summary Bills shall include an abridged summary of electric service usage and charges associated with each meter location. The Company may remove a customer from Summary Billing at its option or at the customer's request. (C)

For the purpose of determining whether to provide Summary Billing, the Company may consider, among other factors, whether the read and due dates of the multiple meter locations allow for Summary Billing without adversely affecting the timely payment of bills, and whether Summary Billing would have an adverse financial impact on the Company.

RULES AND REGULATIONS – (Continued)

BILLS AND NET PAYMENT PERIODS – (Continued)

20.3~~2~~ BILLS Bills for electric service are due and payable upon presentation and may be paid with a check or money order and placed in the payment drop box located at the Company's business office, by any of the means listed under the "Billing and Payment Conveniences" as described on Page 2 of the customer's bill or to any of its collecting agencies during the regular office hours of such agencies. For customers who select an EGS and who select the Separate Billing Option, payment of the bill from the EGS is due to the EGS per the EGS terms and conditions. When the meter readings are taken at other than monthly intervals or when the elapsed time between meter readings is substantially greater or less than one month, the rate values applicable to monthly delivery periods will be adjusted. (C)

20.4~~3~~ BUDGET PAYMENT PLAN FOR RESIDENTIAL CUSTOMERS The Budget Payment Plan provides residential customers the option of paying a budget amount each month based on their average monthly charges over a rolling twelve (12) month period. The Budget Payment Plan is available upon request for residential customers not in arrears for payment of service. The Budget Payment Plan will average utility service charges on an estimated annual basis by account and will be reviewed periodically for adjustment. When the Company provides Consolidated EDC Rate Ready Billing, the EGS's charges for conventionally-priced supply service will be included in the customer's Budget Payment Plan. When the Company provides Consolidated EDC Bill Ready Billing, the EGS's charges for conventionally-priced supply service will be included in the customer's Budget Payment Plan at the EGS's election. If the customer elects a dynamically-priced supply product (e.g., time-of-use pricing, real-time pricing, critical-peak pricing, peak-time rebate pricing, etc.) from the EGS, charges will not be included in the customer's Budget Payment Plan unless the customer receives prior authorization from the EGS and is on Consolidated EDC Rate Ready Billing. If a customer fails to pay an outstanding bill by the required due date, the Company may, in its sole discretion, terminate that customer's enrollment in the Budget Payment Plan and the difference owed the Company shall be immediately due. For customers enrolled in the Budget Payment Plan, the Company will reconcile the difference between the actual amount due and the budget amount paid to date in the twelfth month from the date of the Customer's enrollment in the Plan. Reconciliation amounts will be handled in accordance with Pennsylvania Public Utility Commission regulations including 52 Pa. Code § 56.12. (C) (C)

21. NET PAYMENT Payments placed in the payment drop box at the Company's business office or payments made direct to the Company's collecting agencies will be accepted by the Company in the amount billed as per the terms stated at each respective location. Payments made by mail may be accepted in the amount billed by the Company, at its option, if the payment is received within five (5) days after the due date. A Late Payment Charge will be added to Company charges for failure to make payment of the bill in accord with the above.

21.1 PAYMENT OF BILLS FOR RESIDENTIAL SERVICE The Company will designate a due date on its bill which shall be a business day no less than 20 days from the date of transmittal of the bill. The Company may accommodate changes to due dates for residential customers upon written customer request and when a demonstrated financial burden for the current due date exists for ratepayers receiving Social Security or equivalent monthly checks.

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

BILLS AND NET PAYMENT PERIODS – (Continued)

21.2 PARTIAL PAYMENT OF BILLS For customers who submit payments which are insufficient to cover all of the charges billed by the Company, including EGS charges for those customers who have selected consolidated billing, the Company will apply the payment based upon their outstanding balance, if any, and their current bill, as follows: (1) past due deposit; (2) past-due distribution charges; (3) past-due transmission and supply charges; (4) past due non-basic charges; (5) current deposit; (6) current distribution charges; (7) current transmission and supply charges; and (8) current non-basic charges.

21.3 RETURNED PAYMENT CHARGE If a payment on a Customer's account is returned to the Company unpaid by the Customer's financial institution or another entity responsible for processing payment and cannot be reprocessed by the Company for payment, a $20.00 charge will be added to the Customer's account. If such an occurrence happens a second time within any twelve (12) month period, personal checks and electronic checks will not be accepted by the Company to make the current payment and future payments on the Customer's account until a timely payment history is established by the Customer as defined by 52 Pa. Code § 56.53(b).

COMPANY PROPERTY ON CUSTOMER'S PREMISES

22. ACCESS TO PREMISES Company representatives, who are properly identified, shall have full and free access to the customer's premises at all reasonable times for the purpose of reading Company meters, for inspection and repairs, for removal of Company property, or for any other purpose incident to the service. The Company shall have the right to access customer owned facilities and equipment at all hours for the purposes of responding to an emergency, restoring electric service, rendering the electric facilities safe and reliable, or for the purpose of reducing the likelihood of damage to the Company's facilities or equipment. The customer should immediately communicate with the Company in case of any question as to the authority or credentials of Company representatives. A customer's failure to provide access may be grounds for service termination pursuant to Rule No. 33 herein. (C) (C)

22.1. VEGETATION MANAGEMENT AND RIGHT-OF-WAY The customer, applicant, or property owner shall provide, without charge to the Company, right-of-way and access across property owned or controlled by customer/applicant/property owner, and locations and housings which are suitable, in the opinion of Company, for the construction, reconstruction, maintenance or operation of Company facilities that serve the customer/applicant/property owner. Suitable right-of-way includes, but is not limited to, the right of ingress and egress to and from the electric facilities for any of the purposes aforesaid; and also the right to prune, cut or remove trees, underbrush and other obstructions which, in the judgment of Company, may at any time interfere with the construction, reconstruction, maintenance or operation of the electric facilities, and in connection therewith, the right to treat with herbicides approved for the removal and control of trees, brush and undergrowth. The Company shall also have all of the aforesaid rights related to its provision of underground service to a customer/applicant/property owner, even if the Company does not require the customer/applicant/property owner to execute a formal right-of-way document. (C)

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

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

(C)

RULES AND REGULATIONS - (Continued)

~~**BILLS AND NET PAYMENT PERIODS – (Continued)**~~ (C)

DISCONTINUANCE, CURTAILMENT OR INTERRUPTION OF ELECTRIC SERVICE

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

26. ARREARS The Company upon reasonable notice may terminate electric service and remove its equipment from the premises for nonpayment of undisputed Company service charges, Company charges as the default service charges or EGS receivables purchased by the Company up to the amount that the customer would have paid under Default Service rates during the non-payment period, pursuant to Duquesne's Electric Generation Supplier Coordination Tariff Rule No. 12.1.7. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

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

26.1 COLLECTION REVIEW The Company shall review accounts for collection purposes as reasonable and appropriate. The Company may pursue all lawful means of collection of accounts as permitted by applicable law.

27. CONTRACTS OR APPLICATIONS Where electric service has been established without the customer first having executed a written contract or application, the Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer refuses or neglects to execute a written contract or application when requested so to do by the Company. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

27.1 DEATH OF A RESIDENTIAL CUSTOMER A residential customer shall notify the Company upon the death of any other customer listed on the same residential service account. The Company may request and require proof of death prior to removing the deceased customer from the account. The Company may require evidence of the deceased customer's estate (such as a Decree of Probate) prior to listing the account in the name of the deceased customer's estate. (C)

Where a residential service account is listed solely in the name of a deceased customer, and service is not established in the name of the deceased customer's estate or a different customer, the Company may discontinue the service consistent with 66 Pa. C.S. § 1503.

28. DEPOSITS The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer refuses or neglects to post a cash deposit based on Company charges when requested to do so by the Company, as provided under Rule No. 5. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

29. UNDERGROUND SERVICE The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice when the customer refuses or neglects to provide at his own expense the necessary facilities for receiving underground service, as provided under Rule No. 13.1. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

30. HAZARDOUS AND IMPROPER CONDITIONS The Company may terminate electric service and remove its equipment from the premises if in the judgment of the Company the customer's installation has become dangerous or defective, or if the Company has received a notice from the proper authorities that the customer's equipment is dangerous or defective, or if the customer's equipment or use thereof injuriously affects the equipment of the Company or the Company's service to other customers. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

31. MISREPRESENTATIONS The Company reserves the right to terminate electric service and remove its equipment from the premises in case the customer has made misrepresentations to the Company with respect to the customer's identity or the use of the electric service. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

32. REDISTRIBUTION The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer redistributes the electric service contrary to the provisions set forth in this tariff. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

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

33. INACCESSIBILITY The Company may terminate electric service and remove its equipment from the premises upon reasonable notice in case meter readers or other authorized representatives of the Company cannot gain admittance or are refused admittance to the premises for the purposes of reading Company meters, ~~making repairs, making inspections~~inspection and repairs, ~~or removing~~ removal of Company property, responding to an emergency, restoring electric service, rendering the electric facilities safe and reliable, or for any other purpose incident to the service or in case the customer interferes with Company representatives in the performance of their duties. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service." (C) (C) (C) (C)

34. TAMPERING The Company may terminate electric service and remove its equipment from the premises in case the Company's property on the premises has been interfered with, or in case evidence is found that the service wires, meters, switch-box or other appurtenances on the premises have been tampered with. When a residential customer or residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

35. REPAIRS AND LOSSES The Company may terminate electric service and remove its equipment from the premises upon reasonable notice in case the customer shall neglect or refuse to reimburse the Company for repairs to or loss of the Company's property on the premises when such repairs are necessitated, or loss occasioned, by negligence on the part of the customer. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

36. WRITS AND LEVIES The Company reserves the right to terminate electric service and remove its equipment from the premises upon reasonable notice in case a Writ of Execution is issued against the customer, or in case the premises at which service is supplied is levied upon, or in case of assignment or act of bankruptcy on the part of the customer. When a residential customer or a residence is involved, the Company will comply with the provisions of 52 Pa. Code Chapter 56, "Standards and Billing Practices for Residential Utility Service" and 66 Pa.C.S. § 1406, "Termination of Utility Service."

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

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

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

(C) – Indicates Change

RULES AND REGULATIONS - (Continued)

GENERAL PROVISIONS- (Continued)

45.3 SWITCHING BETWEEN LOCATIONS - (Continued)

1. At least one (1) business day notice to the Company is required to effectuate the move. Requests to start service on the same day as the request will not be honored nor will the Company allow customers to back-date service.

2. The move will not be allowed for any overlapping service or gaps in service lasting more than three (3) days.

3. An EGS must currently be providing service on the customer's account and any termination of EGS service prior to the customer's move will preclude continued service from the same EGS at the new location by the Company.

If the above criteria have been met, the Company will advise the customer that their EGS supply service will seamlessly move to their new location and the Company will send a new move transaction to the EGS.

The move may be terminated or voided after the move transaction is complete under certain circumstances, including where the customer: 1.) voids or terminates the new account prior to the service start date; 2.) requests to change the service start date on the new account to a date occurring in the past; or 3.) enrolls with a new EGS on the current account before the connection to the new account occurs. In these instances, the Company will send a drop notification to the EGS.

45.4 STARTING SERVICE WITH AN EGS Customers starting new service with the Company will be permitted to begin supply service with an EGS on their start date subject to meeting the eligibility requirements in Rule No. 45.3 and conditions set forth in this Rule.

The Company will process EGS service to a new customer provided that the customer has met all of the following criteria:

1. the customer has provided notice to the Company at least three (3) business days prior to the start date for new service;

2. the customer will not be permitted to back-date service;

3. the customer has satisfied all requirements to start service at the new location; and

4. the customer has contacted the EGS to initiate supply service.

46. PROVISION OF LOAD DATA The Company will provide to a customer or its authorized representative historical data in accordance with all current regulatory requirements of direct access ~~once~~ up to five (5) requests (C)
for the same account in a ~~each~~ calendar year ~~for no fee~~ at no charge. All subsequent requests by the customer, (C)
and all requests for historical data by the EGSs or other customer authorized consultant will be provided in accordance with the Supplier Tariff.

47. TAX INDEMNIFICATION If Duquesne Light Company becomes liable under Section 2806(g) or 2809(c) of the Public Utility Code, Pa. C.S. §§ 2806(g) and 2809(f), for Pennsylvania state taxes not paid by an Electric Generation Supplier (EGS), the non-compliant EGS shall indemnify Duquesne for the amount of additional state tax liability imposed upon Duquesne by the Pennsylvania Department of Revenue due to the failure of the EGS to pay or remit to the Commonwealth the tax imposed on its gross receipts under Section 1101 of the Tax Report Code of 1971 or Chapter 28 of Title 66.

(C) – Indicates Change

RATE RS - RESIDENTIAL SERVICE

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, and general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge .... ~~$10.00~~$16.25 (I)

Energy Charge .... ~~4.7054~~ 6.1147 ~~cents~~ per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the “Calculation of Rate” section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

(I) – Indicates Increase

RATE RH - RESIDENTIAL SERVICE HEATING

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and as the sole primary method of space heating except that the space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge .... ~~$10.00~~$16.25 (I)

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge .... ~~3.5742~~ 4.6451 cents per kilowatt hour (I)

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... ~~4.7054~~ 6.1147 cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE RA - RESIDENTIAL SERVICE ADD-ON HEAT PUMP

AVAILABILITY

Available to residential or combined residential and farm customers using the Company's standard low voltage service for lighting, appliance operation, general household purposes and for commercial or professional activity where associated consumption represents less than 25% of the total monthly usage at the premise, and an add-on heat pump for space heating. Other energy sources may be used to supplement the add-on heat pump provided that the supplemental energy source is thermostatically controlled to operate only when the outdoor temperature falls to at least 40^{O} F and the add-on heat pump cannot provide the total heating requirements.

Available only when supplied at 240 volt (or less) single phase service through a single meter directly by the Company to a single family dwelling or to an individual dwelling unit in a multiple dwelling structure. For the purposes of this rate, a dwelling unit is defined as one or more rooms arranged for the use of one or more individuals for shelter, sleeping, dining, and with permanent provisions for cooking and sanitation.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge .... ~~$10.00~~$16.25 (I)

Winter Monthly Rate — For the Billing Months of November through April:

Energy Charge .... ~~1.1492~~ 1.5485 cents per kilowatt hour (I)

Summer Monthly Rate — For the Billing Months of May through October:

Energy Charge .... ~~4.7054~~ 6.1147 cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for residential customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to residential customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(I) – Indicates Increase

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM

AVAILABILITY

Available for all the standard electric service taken on a small or medium general service customer's premises for which a residential rate is not available.

MONTHLY RATE FOR NON-DEMAND ~~METERED~~ CUSTOMERS (C)

DISTRIBUTION CHARGES — RATE GS (C)

Customer Charge .... ~~$10.00~~$16.25 (I)

Energy Charge — All kWh .... ~~5.6713~~ 7.2821 cents per kilowatt-hour (I)

MONTHLY RATE FOR DEMAND ~~METERED~~ CUSTOMERS (C)

DISTRIBUTION CHARGES — RATE GM < 25 kW (C)

Customer Charge .... ~~$42.00~~$56.00 (I)

Energy Charge — All kWh .... ~~1.1061~~ 1.5123 cents per kilowatt-hour (I)

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... ~~$5.60~~ $7.09 per kilowatt (I)

DISTRIBUTION CHARGES — RATE GM ≥ 25 kW (C)

Customer Charge .... ~~$54.00~~$67.00 (I)

Energy Charge — All kWh .... ~~0.9364~~ 0.9381 cents per kilowatt-hour (I)

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... ~~$5.58~~ $7.09 per kilowatt (I)

~~MONTHLY RATE FOR NON-DEMAND METERED CUSTOMERS~~

~~CUSTOMER CHARGE~~

~~Customer Distribution Charge .... $10.00~~

~~ENERGY CHARGES~~

	~~Distribution Charge cents per kilowatt-hour~~
~~All kilowatt-hours~~	~~5.6713~~

~~SUPPLY CHARGES~~

(C) – Indicates Change (I) – Indicates Increase

~~Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.~~

~~MONTHLY RATE FOR DEMAND METERED CUSTOMERS~~

~~DISTRIBUTION CHARGES~~

	~~GM < 25 kW~~	~~GM ≥ 25 kW~~
~~Customer Charge~~	~~$42.00~~	~~$54.00~~
~~Demand Charges~~	**~~$ per kilowatt~~**	
~~First 5 kilowatts or less of Demand~~	~~No Charge~~	~~No Charge~~
~~Additional kilowatts of Demand~~	~~5.60~~	~~5.58~~
~~Energy Charges~~	**~~¢ per kilowatt-hour~~**	
~~All kilowatt-hours~~	~~1.1061~~	~~0.9364~~

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM - (Continued)

MONTHLY RATE FOR NON-DEMAND AND DEMAND ~~METERED~~ CUSTOMERS (C)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for customers will be updated through competitive requests for proposal described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to non-demand ~~metered~~ customers, customers with monthly ~~metered~~ demand less than 25 kW and customers with monthly ~~metered~~ demand equal to or greater than 25 kW shall be as described in Rider No. 8 and for the effective periods defined in Rider No. 8. (C) (C)

~~For purposes of determining the monthly rate for demand metered customers, Duquesne Light shall evaluate the customer's twelve (12) most recent months of monthly metered demand for that customer available in October of the preceding year. If the customer's monthly metered demand is less than 25 kW in each of the twelve (12) months, then that customer shall be charged the monthly rate for demand metered customers less than 25 kW for the next calendar year and automatically assigned to that rate effective with their January billing. If the customer's monthly metered demand is 25 kW or greater for any single month of the twelve (12) month period, then that customer shall be charged the monthly rate for demand metered customers equal to or greater than 25 kW for the next calendar year and automatically assigned to that rate as their default service rate effective with their January billing. In no instance shall a customer be eligible for more than one default service offering at a time. A new customer or a customer with limited or no historical data shall be eligible for and assigned to the applicable rate based on Duquesne Light's estimate of the customer's peak monthly metered demand for the next twelve (12) month period.~~ (C)

A new customer or a customer with limited or no historical data shall be eligible for and assigned to the applicable rate based on Duquesne Light's estimate of the customer's monthly usage and/or peak monthly demand for the next twelve (12) month period. In no instance shall a customer be eligible for more than one of Rate GS, Rate GM < 25kW or Rate GM ≥ 25 kW at a time. (C)

Rate GS Customers A customer's assignment to Rate GS is for a twelve-month period. The Company shall review the customer's rate upon the expiration of such twelve-month period and shall assign the customer to the applicable rate based on a rolling twelve-month average of the customer's usage and billing demand as follows: (C)

- If the customer's average monthly usage is 1,000 kWh or less, and the customer's average monthly billing demand is 5 kW or less, the customer shall be assigned to Rate GS. (C)
- If the customer's average monthly usage is greater than 1,000 kWh, or the customer's average monthly billing demand is greater than 5 kW, the customer shall be assigned to the Rate GM < 25kW or Rate GM ≥ 25 kW, as applicable, effective with the customer's next billing cycle. (C)

Rate GM < 25 kW and Rate GM ≥ 25 kW Customers A customer's assignment to Rate GM < 25kW or to Rate GM ≥ 25 kW is for a period of twelve (12) months or until the customer's next January billing, whichever is longer. Each October, Duquesne Light shall evaluate the customer's average monthly usage and billing demand for the past twelve (12) most recent months, for purposes of determining the customer's rate for the following year. (C)

- If the customer's average monthly usage was 1,000 kWh or less and the customer's average monthly billing demand was 5 kW or less, the customer shall be assigned to Rate GS effective with the customer's next January billing.

(C) – Indicates Change

- If the customer's average monthly billing demand was greater than 5 kW but less than 25 kW, the customer shall be assigned to Rate GM < 25 kW effective with the customer's next January billing.

- If the customer's average monthly billing demand was 25 kW or greater, the customer shall be assigned to Rate GM ≥ 25 kW effective with the customer's next January billing.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(C) – Indicates Change

RATE GS/GM - GENERAL SERVICE SMALL AND MEDIUM - (Continued)

MONTHLY RATE FOR NON-DEMAND AND DEMAND ~~METERED~~ CUSTOMERS - (Continued) (C)

ELECTRIC CHARGES – (Continued) (C)

Customers who elect to purchase their electric energy requirements from an EGS will be charged the Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity at the above Distribution and Supply Charges and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

MINIMUM CHARGE

The Minimum Charge shall be the sum of the Customer Distribution Charge plus a Demand Charge based on 50% of the current month Billing Demand or 30% of the highest Billing Demand, during the preceding eleven months, whichever is greater, plus the current billing period charges for Company supplied transmission and supply service, if any. The Demand Charge shall be determined using the Distribution Charge only, but shall not be less than the Customer Distribution Charge.

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

DETERMINATION OF DEMAND

The demand will be measured where a customer's monthly use exceeds 1,000 kilowatt-hours or where the demand is known to exceed 5 kilowatts. Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen-minute period of greatest kilowatt-hour use during the billing period. Individual demands which exceed 30 kilowatts will be adjusted for power factor by multiplying by

$$\left\{0.8 + \left[0.6 \frac{\text{Reactive Kilovolt - ampere hours}}{\text{Kilowatt - hours}}\right]\right\},$$

where such multiplier will be not less than 1.00 nor more than 2.00. The Billing Demand will be the sum of the individual demands of each metered service, adjusted for power factor as defined above.

CONTRACT PROVISIONS

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

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see “Standard Contract Riders.”

(C) – Indicates Change

RATE GMH - GENERAL SERVICE MEDIUM HEATING

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE (C)

WINTER MONTHLY RATE — FOR THE BILLING MONTHS OF OCTOBER THROUGH MAY (C)

DISTRIBUTION CHARGES (C)

Customer Charge .... ~~$42.00~~$56.00 (I)

Energy Charge — All kWh .... ~~2.4716~~ 3.1725 cents per kilowatt-hour (I)

SUMMER MONTHLY RATE — FOR THE BILLING MONTHS OF JUNE THROUGH SEPTEMBER (C)

DISTRIBUTION CHARGES (C)

Customer Charge .... ~~$42.00~~$56.00 (I)

Energy Charge — All kWh .... ~~1.1061~~ 1.5123 cents per kilowatt-hour (I)

Demand Charge — First five (5) kilowatts or less .... No Charge

— Additional kilowatts of Demand .... ~~$5.60~~ $7.09 per kilowatt (I)

~~**CUSTOMER CHARGE**~~

~~Customer Distribution Charge .... $42.00~~

~~**ENERGY CHARGES**~~

	~~**Distribution Charge cents per kilowatt-hour**~~
~~All kilowatt-hours~~	~~2.4716~~

(C) – Indicates Change (I) – Indicates Increase

~~DEMAND CHARGES~~

	~~Distribution Charge~~ ~~$ per kilowatt~~
~~First 5 kilowatts or less of Demand~~	~~No Charge~~
~~Additional kilowatts of Demand~~	~~5.60~~

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

~~SUMMER MONTHLY RATE – (Continued)~~ (C)

~~For the Billing Months of June through September: - (Continued)~~

~~ENERGY CHARGES~~

	~~Distribution Charge cents per kilowatt-hour~~
~~All kilowatt-hours~~	~~1.1061~~

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for customers will be updated through competitive requests for proposal described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to non-demand ~~metered~~ customers, customers with monthly ~~metered~~ demand less than 25 kW and customers with monthly ~~metered~~ demand equal to or greater than 25 kW shall be as described in Rider No. 8 and for the effective periods defined in Rider No. 8. (C) (C)

For purposes of determining the monthly rate for demand ~~metered~~ customers, Duquesne Light shall evaluate the customer's twelve (12) most recent months of monthly ~~metered~~ billing demand for that customer available in October of the preceding year. If the customer's average monthly ~~metered~~ billing demand is less than 25 kW in ~~each of~~ the twelve (12) months, then that customer shall be charged the monthly rate for demand ~~metered~~ customers less than 25 kW for the next calendar year and automatically assigned to that rate effective with their January billing. If the customer's average monthly ~~metered~~ demand is 25 kW or greater ~~for any single month of~~ in the twelve (12) month period, then that customer shall be charged the monthly rate for demand ~~metered~~ customers equal to or greater than 25 kW for the next calendar year and automatically assigned to that rate as their default service rate effective with their January billing. In no instance shall a customer be eligible for more than one default service offering at a time. A new customer or a customer with limited or no historical data shall be eligible for and assigned to the applicable rate based on Duquesne Light's estimate of the customer's ~~peak~~ average monthly ~~metered~~ billing demand for the next twelve (12) month period. (C) (C) (C) (C) (C) (C) (C) (C)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

RATE GMH - GENERAL SERVICE MEDIUM HEATING - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC CHARGES – (Continued)

Customers who elect to purchase their electric energy requirements from an EGS will be charged the Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity at the above Distribution and Supply Charges and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

MINIMUM CHARGE

For the months of October through May, the Minimum Charge shall be the Customer Distribution Charge for the first kilowatt, plus a Distribution Charge of ~~$6.16~~ $7.09 per kW, plus the current billing period charges for Company supplied transmission and supply service, if any. The Minimum Charge shall not be less than the Customer Distribution Charge. For the months of June through September, the Minimum Charge shall be calculated in accordance with the Minimum Charge provisions in Rate GS/GM. (I)

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

DETERMINATION OF DEMAND

The demand will be measured where a customer's monthly use exceeds 1,000 kilowatt-hours or where the demand is known to exceed 5 kilowatts. The demand will be the sum of individual demands of each metered standard service. Individual demand, except in unusual cases, will be determined by measurement of the average kilowatts during the fifteen-minute period of greatest kilowatt-hour use during the billing period. For the months of June through September, demand will be determined as defined in Rate GS/GM.

(I) – Indicates Increase

RATE GL - GENERAL SERVICE LARGE

AVAILABILITY

Available for all the standard electric service taken on a customer's premises where the demand is not less than 300 kilowatts.

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

DEMAND CHARGES

First 300 kilowatts or less of Demand	~~$2,700.00~~$3,000.00	(I)
Additional kilowatts of Demand	~~$8.09~~ $9.66 per kW	(I)

ELECTRIC CHARGES

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE GLH - GENERAL SERVICE LARGE HEATING

AVAILABILITY

Available for all the standard electric service taken on a customer's premises for which a residential rate is not available, where the Company's service is the sole method of space heating, and where the heat loss of the customer's premises is calculated in accordance with the ASHRAE* Handbook of Fundamentals, and where such calculated heat loss converted into kilowatt-hour consumption during the heating season is determined by the Company to be at least 25% of the customer's entire electric energy requirements during the heating season. The space heating system may be supplemented with renewable energy sources such as solar, wind, wood, or hydro.

*American Society of Heating, Refrigerating and Air Conditioning Engineers

MONTHLY RATE

CUSTOMER CHARGE

Customer Distribution Charge .... ~~$50.00~~$67.00 (I)

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

For the Billing Months of October through May:

ENERGY CHARGES

All kilowatt-hours ~~1.9908~~ 2.4828 cents per kWh (I)

For the Billing Months of June through September:

Rate GL shall apply.

RATE GLH - GENERAL SERVICE LARGE HEATING - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC CHARGES

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

MINIMUM CHARGE

For the months of October through May, the Minimum Charge shall be the Customer Distribution Charge for the first kilowatt plus a Distribution Charge of ~~$7.53~~ $9.66 per kW and the charges for Company supplied transmission and supply, if any. For Company supplied transmission and supply, the transmission charges shall be calculated as set forth in Appendix A and the supply charges shall be calculated as set forth under Rider No. 9. The Minimum Charge shall not be less than the Customer Distribution Charge. For the months of June through September, the Minimum Charge shall be calculated in accordance with the Minimum Charge provisions contained in Rate GL. (I)

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

(C) – Indicates Change (I) – Indicates Increase

RATE L - LARGE POWER SERVICE

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

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

DEMAND CHARGES

Service Voltage Less than 138 kV:

First 5,000 kilowatts or less of Demand	~~$34,900.00~~$48,500.00	(I)
Additional kilowatts of Demand	~~$10.96~~ $11.50 per kW	(I)
~~**Service Voltage 138 Kv and Greater:**~~		(C)
~~Fixed Monthly Charge~~	~~$9,643.14 per month~~	(C)

ELECTRIC CHARGES

The Company will provide and charge for Transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(C) – Indicates Change (I) – Indicates Increase

RATE L - LARGE POWER SERVICE - (Continued)

VOLTAGE CONTROL PROVISION

The customer shall be required to operate ~~his~~ its 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. (C)

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 HVPS - HIGH VOLTAGE POWER SERVICE

AVAILABILITY

Available to customers with Contract On-Peak Demands greater than ~~30,000~~5,000 kilowatts where service is supplied at 69,000 volts or higher. (C)

MONTHLY RATE

SUPPLY

Customers who elect to purchase their electric supply requirements from the Company may do so under the provisions of Rider No. 9 – Day-Ahead Hourly Price Service and will be billed in accordance with the terms contained therein. (C)

DISTRIBUTION

FIXED MONTHLY CHARGE

Up to and Including 50,000 kW Billing Demand	~~$7,741.15~~$7,482.78	(D)
50,001 kW to 100,000 kW Billing Demand	~~$12,092.20~~$11,688.61	(D)
Greater than 100,000 kW Billing Demand	~~$17,148.61~~$16,576.26	(D)

ELECTRIC CHARGES

The Company will provide and charge for Transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy requirements from an EGS will be charged the full Distribution Charge by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the supplier becomes unavailable or during which the customer has not chosen a supplier, the Company will supply electricity pursuant to Rider No. 9 – Day-Ahead Hourly Price Service. (C)

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

RATE HVPS - HIGH VOLTAGE POWER SERVICE - (Continued)

MONTHLY RATE - (Continued)

MINIMUM CHARGE

The Minimum Charge shall be the Demand Charge based on 70% of the Contract On-Peak Demand for transmission and distribution and the Demand Charge as calculated under Rider No. 9 for Company supplied supply. The Demand Charge shall be determined using the Distribution Charge, and the Transmission and Supply Charges associated with Company supplied transmission and supply, if any, but in total not less than the demand charges associated with the first ~~30,000~~5,000 kWs or less of demand. (C)

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 fifteen 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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

DETERMINATION OF DEMAND FOR DISTRIBUTION

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~~5,000 kilowatts, whichever is the greater. (C)

ON-PEAK AND OFF-PEAK CONTRACT DEMAND

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

RATE HVPS - HIGH VOLTAGE POWER SERVICE - (Continued)

CONTRACT PROVISION – (Continued)

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~~5,000 kilowatts if the customer remains on this rate. (C)

VOLTAGE CONTROL PROVISION

The customer shall be required to operate ~~his~~ its 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. (C)

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%.

FACILITIES CHARGE

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

(C) – Indicates Change

RATE AL - ARCHITECTURAL LIGHTING SERVICE

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

DISTRIBUTION CHARGES

Customer Charge .... ~~$6.89~~$8.00 (I)

Demand Charge .... ~~$1.29~~ $1.59 per kilowatt (I)

Energy Charge .... ~~0.1817~~ 0.2110 cents per kilowatt hour (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate AL – Architectural Lighting Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate AL customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company, and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(I) – Indicates Increase

RATE AL - ARCHITECTURAL LIGHTING SERVICE - (Continued)

STANDARD CONTRACT RIDERS

For modifications of the above rate under special conditions, see “Standard Contract Riders.”

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.~~ (C)

RATE SE - STREET LIGHTING ENERGY

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

DISTRIBUTION CHARGE

Monthly charge per lamp.......... ~~$2.78~~$2.91 (I)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SE – Street Lighting Energy customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate SE customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(I) – Indicates Increase

RATE SM - STREET LIGHTING MUNICIPAL

AVAILABILITY

Available for mercury vapor, high pressure sodium and light-emitting diode (LED) 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 m~~Mercury vapor street lighting is only available where served prior to January 30, 1983, and continuously thereafter at the same location.~~)~~ Beginning January 1, 2019, replacement of mercury vapor lamps, fixtures or luminaries, including brackets and ballasts, will not be available. In such cases, the customer must take service under one of the available lighting unit options listed below. (C) (C)

A minimum of ten (10) LED lights per customer per individual order is required and must be installed in a contiguous location when replacing existing lighting. (C)

The Company shall not be required to install more than 3,000 LED lights annually. (C)

MONTHLY RATE

DISTRIBUTION CHARGE — Monthly Rate Per Unit (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment — Distribution Charge per Unit	Customer Owned and Maintained Equipment — Distribution Charge per Unit	(C)
Mercury Vapor				
100	44	~~$12.10~~$12.69	$2.71	(I)(C)
175	74	~~$12.35~~$12.95	$2.71	(I)(C)
250	102	~~$12.59~~$13.20	$2.71	(I)(C)
400	161	~~$13.09~~$13.73	$2.71	(I)(C)
1,000	386	~~$15.06~~$15.79	$2.71	(I)(C)
Sodium Vapor				
70	29	~~$12.50~~$13.11	$2.71	(I)(C)
100	50	~~$12.60~~$13.21	$2.71	(I)(C)
150	71	~~$12.78~~$13.40	$2.71	(I)(C)
250	110	~~$13.11~~$13.75	$2.71	(I)(C)
400	170	~~$13.64~~$14.30	$2.71	(I)(C)
1,000	387	~~$15.68~~$16.44	$2.71	(I)(C)

RATE SM - STREET LIGHTING MUNICIPAL - (Continued)

MONTHLY RATE – (Continued) (C)

DISTRIBUTION CHARGE — Monthly Rate Per Unit - (Continued) (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment Distribution Charge per Unit	Customer Owned and Maintained Equipment Distribution Charge per Unit	
Light-Emitting Diode (LED) — Cobra Head				(C)
~~43~~	~~15~~	~~$11.16~~	—	
~~106~~	~~37~~	~~$12.82~~	—	
45	16	$13.01	$2.71	
60	21	$13.52	$2.71	
95	34	$13.99	$2.71	
139	49	$15.08	$2.71	
219	77	$17.54	$2.71	
275	97	$19.24	$2.71	
Light-Emitting Diode (LED) — Colonial				(C)
48	17	$12.18	$2.71	
83	29	$12.18	$2.71	
Light-Emitting Diode (LED) — Contemporary				(C)
47	17	$14.19	$2.71	
62	22	$14.19	$2.71	

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate SM – Street Lighting Municipal customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate SM customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

(C)

RATE SM - STREET LIGHTING MUNICIPAL - (Continued) (C)

MONTHLY RATE – (Continued)

ELECTRIC CHARGES – (Continued) (C)

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

POLES

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 the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of ~~$9.84~~ $10.32 for each pole required. (I)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE (C)

A per unit monthly charge whenever the customer or an agent of the customer owns the entire street lighting system, including, but not limited to, the fixture, pole, circuit, controls, and all other related equipment on the load side of the Company's service point or when such facility is provided by a public agency and the customer and/or agent is obligated to operate and maintain such facility.

The street lighting system equipment must be approved by and installed in a manner acceptable to the Company and must be equipped with photocells or other such equipment that permit only dusk-to-dawn operation.

RATE SM - STREET LIGHTING MUNICIPAL - (Continued) (C)

MONTHLY RATE – (Continued)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE – (Continued) (C)

The customer/agent must provide the Company with a written inventory of all street lighting fixtures. This inventory shall include the location, type and wattage rating for each fixture. The customer/agent will update its inventory of lighting fixtures by informing the Company in writing of changes in type, rating, location, and quantity of lighting fixtures as such changes occur and billings will be adjusted accordingly.

The Company reserves the right to inspect the equipment at each location and make prospective adjustments in billing as indicated by such inspections. The Company shall be under no obligation to conduct such inspections for the purpose of determining accuracy of billing or otherwise. The Company's decision not to conduct such inspections shall not release the customer/agent from the obligation to provide to the Company, and to update, an accurate inventory of the types, ratings, and quantities of lighting equipment upon which billing is based.

As this service is a per unit monthly charge, the customer/agent agrees to pay amounts billed in accordance with the current inventory, regardless of whether any of the equipment was electrically operable during the period in question and regardless of the cause of any such equipment's failure to operate.

The contract period is as covered by any existing contract now in effect with the customer/agent. All new contracts shall be for a period of one year.

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.

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.

5. Non-standard installations. The Company may offer non-standard lighting units and installations in addition to those listed in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract, based on the incremental cost over that listed in the Monthly Rate Table. (C)

RATE SH - STREET LIGHTING HIGHWAY

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

DISTRIBUTION CHARGE — Monthly Rate Per Unit (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment Distribution Charge per Unit	Customer Owned and Maintained Equipment Distribution Charge per Unit	(C)
Sodium Vapor				
100	50	~~$11.96~~$12.54	$2.71	(I)(C)
150	71	~~$12.12~~$12.71	$2.71	(I)(C)
200	95	~~$12.29~~$12.89	$2.71	(I)(C)
400	170	~~$12.94~~$13.57	$2.71	(I)(C)
Light-Emitting Diode (LED) — Cobra Head				(C)
60	21	$13.52	$2.71	
95	34	$13.99	$2.71	
139	49	$15.08	$2.71	
219	77	$17.54	$2.71	

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

(C)

RATE SH - STREET LIGHTING HIGHWAY - (Continued)

MONTHLY RATE - (Continued)

ELECTRIC CHARGES (C)

The Supply Charges for Rate SH – Street Lighting Highway customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate SH customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE (C)

A per unit monthly charge whenever the customer or an agent of the customer owns the entire street lighting system, including, but not limited to, the fixture, pole, circuit, controls, and all other related equipment on the load side of the Company's service point or when such facility is provided by a public agency and the customer and/or agent is obligated to operate and maintain such facility.

The street lighting system equipment must be approved by and installed in a manner acceptable to the Company and must be equipped with photocells or other such equipment that permit only dusk-to-dawn operation.

(C) – Indicates Change

RATE SH - STREET LIGHTING HIGHWAY - (Continued)

MONTHLY RATE - (Continued)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE – (Continued) (C)

The customer/agent must provide the Company with a written inventory of all street lighting fixtures. This inventory shall include the location, type and wattage rating for each fixture. The customer/agent will update its inventory of lighting fixtures by informing the Company in writing of changes in type, rating, location, and quantity of lighting fixtures as such changes occur and billings will be adjusted accordingly.

The Company reserves the right to inspect the equipment at each location and make prospective adjustments in billing as indicated by such inspections. The Company shall be under no obligation to conduct such inspections for the purpose of determining accuracy of billing or otherwise. The Company's decision not to conduct such inspections shall not release the customer/agent from the obligation to provide to the Company, and to update, an accurate inventory of the types, ratings, and quantities of lighting equipment upon which billing is based.

As this service is a per unit monthly charge, the customer/agent agrees to pay amounts billed in accordance with the current inventory, regardless of whether any of the equipment was electrically operable during the period in question and regardless of the cause of any such equipment's failure to operate.

The contract period is as covered by any existing contract now in effect with the customer/agent. All new contracts shall be for a period of one year.

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. (C)

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.

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.

(C)

(C) – Indicates Change

RATE SH - STREET LIGHTING HIGHWAY - (Continued) (C)

SPECIAL TERMS AND CONDITIONS - (Continued)

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.

9. Non-standard installations. The Company may offer non-standard lighting units and installations in addition to those listed in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract, based on the incremental cost over that listed in the Monthly Rate Table. (C)

TERM OF CONTRACT

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

RATE UMS – UNMETERED SERVICE

AVAILABILITY

Available to customers using unmetered standard service at each point of connection for customer-owned and maintained equipment such as traffic signals, communication devices and billboard lighting.

MONTHLY RATE

DISTRIBUTION CHARGES

Customer Charge $10.00

Energy Charge .... ~~1.5744~~ 1.2822 cents per kilowatt hour (D)

SUPPLY CHARGES

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate UMS – Unmetered Service customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate UMS customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8.

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charges, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may elect Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

(D) – Indicates Decrease

RATE PAL - PRIVATE AREA LIGHTING

AVAILABILITY

Available for high pressure sodium lighting and flood lighting of residential, commercial and industrial private property installations including parking lots, for normal dusk to dawn operation of approximately 4,200 hours per year.

MONTHLY RATE

DISTRIBUTION CHARGE - Monthly Rate Per Unit (C)

Minimum Nominal Lamp Wattage	Nominal kWh Energy Usage per Unit per Month	Company Owned and Maintained Equipment Distribution Charge per Unit	Customer Owned and Maintained Equipment Distribution Charge per Unit	(C)
High Pressure Sodium				
70	29	~~$12.50~~$13.11	~~$2.78~~$2.71	(I)(D)
100	50	~~$12.60~~$13.21	~~$2.78~~$2.71	(I)(D)
150	71	~~$12.78~~$13.40	~~$2.78~~$2.71	(I)(D)
250	110	~~$13.11~~$13.75	~~$2.78~~$2.71	(I)(D)
400	170	~~$13.64~~$14.30	~~$2.78~~$2.71	(I)(D)
Flood Lighting				
100	46	~~$12.50~~$13.11	$2.71	(I)(D)
250	100	~~$13.08~~$13.72	$2.71	(I)(D)
400	155	~~$13.67~~$14.33	$2.71	(I)(D)
Light-Emitting Diode (LED) — Cobra Head				(C)
45	16	$13.01	$2.71	
60	21	$13.52	$2.71	
95	34	$13.99	$2.71	
139	49	$15.08	$2.71	
219	77	$17.54	$2.71	
275	97	$19.24	$2.71	
Light-Emitting Diode (LED) — Colonial				(C)
48	17	$12.18	$2.71	
83	29	$12.18	$2.71	
Light-Emitting Diode (LED) — Contemporary				(C)
47	17	$14.19	$2.71	
62	22	$14.19	$2.71	

~~UNMETERED ENERGY FOR CUSTOMER OWNED AND MAINTAINED EQUIPMENT~~ (C)

~~70~~	~~29~~	~~$2.78~~

(C) – Indicates Change (I) – Indicates Increase

~~100~~	~~46~~	~~$2.78~~
~~150~~	~~67~~	~~$2.78~~
~~250~~	~~100~~	~~$2.78~~
~~400~~	~~155~~	~~$2.78~~

RATE PAL - PRIVATE AREA LIGHTING - (Continued)

MONTHLY RATE - (Continued)

SUPPLY CHARGES (C)

Customers who elect to purchase their electric supply requirements from the Company will do so under the provisions of Rider No. 8 – Default Service Supply and will be billed in accordance with the terms contained therein.

ELECTRIC CHARGES

The Supply Charges for Rate ~~UMS – Unmetered Service~~PAL – Private Area Lighting customers will be updated through competitive requests for proposal as described in Rider No. 8 – Default Service Supply. The Supply rate shall be determined based on the formula described in the "Calculation of Rate" section in Rider No. 8. Applicability of the Supply rate to Rate UMS customers shall be as described in Rider No. 8 and for the effective period defined in Rider No. 8. (C)

The Company will provide and charge for transmission service consistent with the PJM Open Access Transmission Tariff approved or accepted by the Federal Energy Regulatory Commission for customers who receive Default Service from the Company. The Transmission Service Charges are included, for informational purposes, in Appendix A of this Tariff.

Customers who elect to purchase their electric energy supply requirements from an EGS will be charged the Distribution Charges by the Company and must purchase their transmission and supply requirements from their selected EGS. Customers may change suppliers or return to the Company for electric supply requirements as defined in Rule No. 45.

For customers who elect to purchase their supply from an EGS, the customer is responsible for any other charges from the EGS. Any month in which the EGS becomes unavailable or during which the customer has not chosen an EGS, the Company will supply electricity at the above Distribution Charge, the Supply Charges in Rider No. 8 and the Transmission Service Charges in Appendix A.

Customers who choose an EGS may select Consolidated Billing or Separate Billing as defined in Rule No. 20.1.

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 Company charges on the bill. The Charge shall be calculated on the overdue portions of the Company charges on the bill and shall not be charged against any sum that falls due during a current billing period.

POLES

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.

(C) – Indicates Change

RATE PAL - PRIVATE AREA LIGHTING - (Continued)

MONTHLY RATE - (Continued)

POLES – (Continued)

Where the installation of one (1) or more wood poles is required to serve the customer, the customer has the option to install the pole(s) at his own expense in accordance with SPECIAL TERM AND CONDITION NO. 2 or the Company will install, own and maintain the pole(s) and bill the customer at the monthly rate of ~~$9.84~~ $10.32 for ech pole required. (I)

CUSTOMER OWNED AND MAINTAINED EQUIPMENT CHARGE (C)

A per unit monthly charge whenever the customer or an agent of the customer owns the entire street lighting system, including, but not limited to, the fixture, pole, circuit, controls, and all other related equipment on the load side of the Company's service point or when such facility is provided by a public agency and the customer and/or agent is obligated to operate and maintain such facility.

The street lighting system equipment must be approved by and installed in a manner acceptable to the Company and must be equipped with photocells or other such equipment that permit only dusk-to-dawn operation.

The customer/agent must provide the Company with a written inventory of all street lighting fixtures. This inventory shall include the location, type and wattage rating for each fixture. The customer/agent will update its inventory of lighting fixtures by informing the Company in writing of changes in type, rating, location, and quantity of lighting fixtures as such changes occur and billings will be adjusted accordingly.

The Company reserves the right to inspect the equipment at each location and make prospective adjustments in billing as indicated by such inspections. The Company shall be under no obligation to conduct such inspections for the purpose of determining accuracy of billing or otherwise. The Company's decision not to conduct such inspections shall not release the customer/agent from the obligation to provide to the Company, and to update, an accurate inventory of the types, ratings, and quantities of lighting equipment upon which billing is based.

As this service is a per unit monthly charge, the customer/agent agrees to pay amounts billed in accordance with the current inventory, regardless of whether any of the equipment was electrically operable during the period in question and regardless of the cause of any such equipment's failure to operate.

The contract period is as covered by any existing contract now in effect with the customer/agent. All new contracts shall be for a period of one year.

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.

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.

(C)

(I) – Indicates Increase (C) – Indicates Change

RATE PAL - PRIVATE AREA LIGHTING - (Continued) (C)

SPECIAL TERMS AND CONDITIONS – (Continued)

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.

5. Non-standard installations. The Company may offer non-standard lighting units and installations in addition to those listed in the Monthly Rate Table. For customers requesting such service, there will be an additional charge, as specified in the customer's contract, based on the incremental cost over that listed in the Monthly Rate Table. (C)

STANDARD CONTRACT RIDERS – (Continued)

RIDER MATRIX

	RS	RH	RA	GS/GM	GMH	GL	GLH	L	HVPS	AL	SE	SM	SH	UMS	PAL	
Rider No. 1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Rider No. 2				X	X	X	X									
Rider No. 3				X	X	X	X	X								
Rider No. 4				~~X~~	~~X~~	~~X~~	~~X~~									(C)
Rider No. 5	X	X	X													
Rider No. 6				X												
Rider No. 7	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	(C)
Rider No. 8	X	X	X	X	X					X	X	X	X	X	X	
Rider No. 9						X	X	X	X							
Rider No. 10	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Rider No. 11				X		X										
Rider No. 12				X	X											
Rider No. 13				X												
Rider No. 14	X															
Rider No. 15																
Rider No. 15A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Rider No. 16				X	X	X	X	X								
Rider No. 17						X	X	X	X							
Rider No. 18	X	X	X	X	X	X	X									
Rider No. 19																
Rider No. 20	X	X	X	X	X	X	X	X	X	X						
Rider No. 21	X	X	X	X	X	X										
Rider No. 22	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Appendix A	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Rider Titles:

Rider No. 1 — Retail Market Enhancement Surcharge
Rider No. 2 — Untransformed Service
Rider No. 3 — School and Government Service Discount Period
Rider No. 4 — ~~Budget Billing HUD Finance Multi-Family Housing~~Intentionally Left Blank (C)
Rider No. 5 — Universal Service Charge
Rider No. 6 — Temporary Service
Rider No. 7 — ~~SECA Charge~~Intentionally Left Blank (C)
Rider No. 8 — Default Service Supply
Rider No. 9 — Day-Ahead Hourly Price Service
Rider No. 10 — State Tax Adjustment
Rider No. 11 — Street Railway Service
Rider No. 12 — Billing Option – Volunteer Fire Companies and Nonprofit Senior Citizen Centers
Rider No. 13 — General Service Separately Metered Electric Space Heating Service
Rider No. 14 — Residential Service Separately Metered Electric Space and Water Heating
Rider No. 15 — Intentionally Left Blank
Rider No. 15A — Phase III Energy Efficiency and Conservation Surcharge
Rider No. 16 — Service to Non-Utility Generating Facilities
Rider No. 17 — Emergency Energy Conservation
Rider No. 18 — Rates for Purchase of Electric Energy from Customer-Owned Renewable Resources Generating Facilities
Rider No. 19 — Intentionally Left Blank
Rider No. 20 — Smart Meter Charge
Rider No. 21 — Net Metering Service
Rider No. 22 — Distribution System Improvement Charge ("DSIC")
Appendix A — Transmission Service Charges

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 1 – RETAIL MARKET ENHANCEMENT SURCHARGE

(Applicable to all Rates)

The Retail Market Enhancement Surcharge ("RMES") is instituted as a cost recovery mechanism to recover all eligible costs incurred by the Company associated with implementing Commission-mandated activities, programs, projects, services etc. to enhance the competitive energy market in Pennsylvania. As an example, some of the mandated activities may be found in, but are not limited to, Commission Order's at Docket No. I-2011-2237952, Docket No. M-2013-2355751, and Docket No. M-2014-2401345. ~~In addition, in accordance with the Commission's Order entered on December 22, 2016, at Docket No. P-2016-2543140, beginning June 1, 2017, the RMES recovers the Purchase of Receivables ("POR") program discount expense associated with the uncollectible expense of Electric Generation Supplier ("EGS") consolidated billings.~~ The RMES shall remain in effect to recover all expenses associated with Commission-mandated consumer education and retail market enhancement activities that are directed by the Commission to be recovered through the RMES or other Commission-approved mechanism and that are not otherwise being recovered in base rates. Consumer education activities shall also include those expenses to educate low-income and Customer Assistance Program ("CAP") customers about shopping in the retail market. The RMES will be recomputed annually and filed, to be effective June 1 of each year, unless the new rate is such a small change as to warrant no change in rates. The RMES shall be applied to all customers' bills. The RMES process will reconcile actual expense with revenue billed in accordance with this Rider. (C)

MONTHLY RETAIL MARKET ENHANCEMENT SURCHARGE RATES

(C)

Tariff Rate Class	Monthly RME Surcharge per Customer (cents)	~~Monthly POR Surcharge per Customer (cents)~~	~~Total (cents)~~
Rate RS	(2.00)	~~10.00~~	~~8.00~~
Rate RH	(2.00)	~~10.00~~	~~8.00~~
Rate RA	(2.00)	~~10.00~~	~~8.00~~
Rate GS	(1.00)	~~16.00~~	~~15.00~~
Rate GM < 25 kW	(1.00)	~~16.00~~	~~15.00~~
Rate GM > 25 kW	(3.00)	~~98.00~~	~~95.00~~
Rate GMH < 25 kW	(1.00)	~~16.00~~	~~15.00~~
Rate GMH > 25 kW	(3.00)	~~98.00~~	~~95.00~~
Rates GL, GLH, L and HVPS	(1.00)	~~0.00~~	~~(1.00)~~
Rates AL, SE, UMS, SM, SH and PAL	(5.00)	~~0.00~~	~~(5.00)~~

CALCULATION OF RATES

The RMES, calculated independently for each customer class in this Tariff, shall be applied to all customers served under the Tariff. The RMES shall be determined in cents per month in accordance with the formula set forth below and shall be applied to all customers served during any part of a billing month:

$$\mathbf{RMES = [\ \cancel{(}\ (\ (\ RME - e\ )\ \cancel{+\ POR\ )}\ /\ (\ C * 12\ ) * 100\ )\ ] * [\ 1\ /\ (\ 1 - T\ )\ ]}$$ (C)

Where **RMES** = Retail Market Enhancement Surcharge, a fixed charge in cents per month, to be billed to each customer served under the applicable Tariff rate class.

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 1 – RETAIL MARKET ENHANCEMENT SURCHARGE – (Continued)

(Applicable to all Rates)

CALCULATION OF RATES – (CONTINUED)

RME = Projected annual expenses associated with retail market enhancement, consumer education activities and CAP customer education mandated by the Commission in dollars for each customer class for the filing year. CAP customer education dollars shall be assigned to the Residential customer class for cost recovery purposes.

~~**POR** = The annual expense of $797,900 associated with the Purchase of Receivables program discount for each customer class based on calendar year 2015 data. This amount shall remain fixed.~~ (C)

C = Projected average number of customers per customer class for the filing year.

e = The net overcollection or undercollection of the consumer education and retail market enhancement related expenses directed by the Commission as computed for each customer class as of the end of the reconciliation year.

T = The Pennsylvania Gross Receipts Tax in effect during the billing month, expressed in decimal form.

ANNUAL UPDATE

The RMES defined herein will be updated effective June 1 of each year unless, upon determination, the rates then in effect would result in a significant over or under collection. On or about January 31, the Company will file a reconciliation of the revenue and expense for the previous calendar year. On or about April 1 of the filing year, the Company will file revised RMES rates with the Commission defining rates in effect from June 1 to May 31 of the following year. These rates shall be determined based on the projected budget and number of customers for the filing year and the over or under collection of expenses based on actual RMES revenue and expense incurred for the previous calendar year, the reconciliation year. If it is determined that a significant over or under collection will occur, the Company shall file a revised RMES to become effective on no less than ten (10) day notice.

MISCELLANEOUS

No interest will be included in the RMES.

Rider No. 10 – State Tax Adjustment Surcharge (STAS) shall be applicable to the surcharge defined in this Rider.

The RMES will be added to the monthly Customer Charge of each rate schedule or added as a line item on the monthly bill, as applicable.

The Company shall file reconciliation statements annually.

The RMES shall be subject to review and audit by the Commission.

The RMES shall remain in effect until otherwise directed by the Commission and until the final reconciliation statement is approved and charges fully recovered.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued) (C)

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

~~**(Applicable to Rates GS/GM, GL, GMH, and GLH)**~~

~~Budget billing for electric 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 charges for electric service to be billed hereunder for a twelve-month period. A budget bill for approximately one-twelfth of such estimate will be rendered monthly. For customers who purchase their electricity from an Electric Generation Supplier (EGS) and who have selected Consolidated Billing from the Company as defined in Rule 20.1, this rider shall apply to Company charges and to EGS charges if the EGS has provided authorization to accept the provisions of this rider. 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.~~

THIS PAGE INTENTIONALLY LEFT BLANK

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 – UNIVERSAL SERVICE CHARGE
(Applicable to Rate Schedules RS, RH and RA)

APPLICABILITY

The Universal Service Charge ("USC") is instituted as a cost recovery mechanism to recover the costs incurred by the Company to provide its Commission approved Universal Service and Energy Conservation Plan. The USC shall be applicable to all residential customers who take distribution service under Rate Schedules RS, RH and RA except for residential customers in the Company's Customer Assistance Program ("CAP"). The USC provides for the recovery of the costs, excluding internal administrative costs, associated with universal service programs provided by the Company to residential customers. The USC shall be determined to the nearest one-thousandth of one (1) cent per kilowatt-hour ("kWh") in accordance with the formula set forth below and shall be applied to all kilowatt-hours delivered during the billing month. The USC is a non-bypassable charge.

RATE

In addition to the charges provided in this Tariff, an amount of 0.972 cents per kilowatt-hour shall be added to the distribution energy charges per kilowatt-hour of each applicable rate schedule to determine the total per kilowatt-hour charge. The USC shall not be applicable to customers enrolled in the Company's CAP.

CALCULATION OF CHARGE

$$USC = [(US_c - Cr - E) / S_{Res}] * 100 * [1 / (1 - T)]$$

Where: USC = The charge, in cents per kilowatt-hour, to be applied to each kilowatt-hour delivered to all applicable non-CAP customers who take distribution service under the residential retail rate schedules under this Tariff.

US_c = Universal Service Program costs, which are the estimated direct and external administrative costs to be incurred by the Company to provide Universal Service to customers for the USC Computational Year. Such costs shall include, but are not limited to, preparation of the Needs Assessment, Universal Service Plan development, Impact Evaluation and educational materials. Universal Service Programs include the following programs which may change from time to time:

- Customer Assistance Program ("CAP"): CAP costs will be calculated to include the projected CAP discount and CAP program costs for the Computational Year. The total CAP discount will be based on the annual average discount from the previous year, the Reconciliation Year, multiplied by the projected average number of CAP program participants during the Computational Year. ~~The CAP discount shall be reduced by the~~ (C)
~~annual Low Income Home Energy Assistance Program ("LIHEAP") funds received by~~ (C)
~~CAP customers during the previous LIHEAP program year. The annual average discount~~ (C)
~~from the previous year will be calculated as the difference between the bill at current~~ (C)
~~rates and the CAP payment from customers during the~~ (C)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 5 – UNIVERSAL SERVICE CHARGE - (Continued)
(Applicable to Rate Schedules RS, RH and RA)

CALCULATION OF CHARGE – (Continued)

~~previous year at normalized annual sales volumes.~~ The projected customer additions to the CAP program during the Computational Year will be based on the number of CAP customers receiving a discount at the end of the Reconciliation Year plus a projection of the average monthly number of CAP customers during the Computational Year. The projected number of CAP customers will include net additions to the program (additions minus exits), ~~an estimate of the average monthly number of auto-enrolled customers receiving a discount,~~ and a projection of customers enrolled through expected changes in policy (e.g. changes in the definition of poverty, changes in regulatory mandates). ~~An auto-enrolled customer is not considered to be a CAP participant for purposes of this Rider unless and until the customer has completed the CAP enrollment process.~~ The projected CAP program costs will include the estimated costs for new applications, maintenance and annual recertification, and the projected CAP pre-program arrearages to be forgiven and written off during the USC Computational Year. (C (C) (C) (C)

- Smart Comfort Program [Low Income Usage Reduction Program ("LIURP")]: LIURP costs will be calculated based on the projected number of homes that participate in the usage reduction program and the average cost per visit.
- Customer Assistance and Referral Evaluation Services ("CARES"): CARES costs will be calculated based on the projected annual Community Based Organization ("CBO") program costs and CBO costs for administering the program.
- Hardship Fund: Hardship Fund costs will be calculated based on the projected annual program costs and CBO costs for administering the program.
- Any other replacement or Commission-mandated Universal Service Program or low income program that is implemented during the Reconciliation or Computational Year.

Cr = A credit to reduce CAP customer discounts included in the USC to the extent that the monthly CAP enrollment level exceeds ~~41,650~~ 39,088 customers. Specifically, the recoverable CAP discounts will be reduced by the number of CAP participants in excess of ~~41,650~~ 39,088 times the average CAP credit and arrearage forgiveness costs times 10.43%. The participation level above which the offset shall be applied will be reset in each distribution rate case. (C) (C)

E = The over- or under- collection of actual Universal Service Program costs and revenue that result from the billing of the USC during the USC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly at the statutory legal rate of interest, from the month the over or under collection occurs to the effective month that the over collection is refunded or the under collection is recouped.

(C) – Indicates Change

STANDARD CONTRACT RIDERS – (Continued) (C)

~~RIDER NO. 7 – SECA CHARGE~~

~~(Applicable to the Transmission Charges in All Rate Schedules)~~

~~The Seams Elimination Charge Adjustment ("SECA") Charge billed under this Rider is a pass-through of all charges incurred by the Company that are imposed by the PJM Interconnection, Inc. ("PJM") under its Open Access Transmission Tariff related to the elimination of Regional Through and Out Rates ("RTORs") for transmission service within PJM as it is presently constituted, including the Duquesne zone, and for transmission service between PJM and the Midwest Independent Transmission System Operator ("SECA Charges"). SECA Charges include all costs associated with the elimination of RTORs, including any related increases in transmission rates imposed by PJM on the Company.~~

~~The SECA Charge billed under this Rider shall be $0.001557 per kWh, and it shall apply to all customers who purchase their electric transmission requirements from the Company.~~

~~The SECA Charge billed under this Rider shall be subject to reconciliation. Amounts billed to customers under the SECA Charge will be reconciled against actual SECA Charges paid by the Company and subject to Commission audit.~~

~~The SECA charges imposed by PJM are under review and resolution by the Federal Energy Regulatory Commission ("FERC"). The above SECA Charge was billed through December 11, 2006, to recover costs incurred by the Company through such time. This Rider will remain in effect until the level of SECA Charges paid by the Company has been fully recovered, at which time the SECA Charge billed under this Rider will terminate, subject to any final reconciliation required due to final resolutions of litigation. If the SECA Charge billed under this Rider recovers more than the level of SECA Charges actually incurred by the Company, the Company will terminate the SECA Charge billed under this Rider and submit a plan of refund to the Commission for its approval.~~

THIS PAGE INTENTIONALLY LEFT BLANK

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting

(Rate Schedules SM, SH and PAL)

Lamp wattage as available on applicable rate schedule.

June 1, 2017 through May 31, 2018~~, and~~ June 1, 2018 through May 31, 2019 and (C)
January 1, 2019 through May 31, 2019 (C)

		Application Period					
Wattage	Nominal kWh Energy Usage per Unit per Month	06/01/2017 through 11/30/2017	12/01/2017 through 05/31/2018	06/01/2018 through 11/30/2018	12/01/2018 through 05/31/2019	01/01/2019 through 05/31/2019	(C)
Supply Charge ¢ per kWh		3.7939	3.8177	3.6653	X.XXXX	X.XXXX	
		Fixture Charge — $ per Month					
Mercury Vapor							
100	44	1.67	1.68	1.61	X.XX	—	
175	74	2.81	2.83	2.71	X.XX	—	
250	102	3.87	3.89	3.74	X.XX	—	
400	161	6.11	6.15	5.90	X.XX	—	
1000	386	14.64	14.74	14.15	X.XX	—	
High Pressure Sodium							
70	29	1.10	1.11	1.06	X.XX	—	
100	50	1.90	1.91	1.83	X.XX	—	
150	71	2.69	2.71	2.60	X.XX	—	
200	95	3.60	3.63	3.48	X.XX	—	
250	110	4.17	4.20	4.03	X.XX	—	
400	170	6.45	6.49	6.23	X.XX	—	
1000	387	14.68	14.77	14.18	X.XX	—	
Flood Lighting - Unmetered							
70	29	1.10	1.11	1.06	X.XX	—	
100	46	1.75	1.76	1.69	X.XX	—	
150	67	2.54	2.56	2.46	X.XX	—	
250	100	3.79	3.82	3.67	X.XX	—	
400	155	5.88	5.92	5.68	X.XX	—	
Light-Emitting Diode (LED) — Cobra Head							(C)
~~43~~	~~15~~	~~0.57~~	~~0.57~~	~~0.55~~	~~X.XX~~	—	
~~106~~	~~37~~	~~1.40~~	~~1.41~~	~~1.36~~	~~X.XX~~	—	
45	16	—	—	—	—	X.XX	
60	21	—	—	—	—	X.XX	
95	34	—	—	—	—	X.XX	
139	49	—	—	—	—	X.XX	
219	77	—	—	—	—	X.XX	
275	97	—	—	—	—	X.XX	
Light-Emitting Diode (LED) — Colonial							(C)
48	17	—	—	—	—	X.XX	
83	29	—	—	—	—	X.XX	
Light-Emitting Diode (LED) — Contemporary							(C)
47	17	—	—	—	—	X.XX	
62	22	—	—	—	—	X.XX	

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

DEFAULT SERVICE SUPPLY RATE – (Continued)

Lighting — (Continued)

(Rate Schedules SM, SH and PAL)

Lamp wattage as available on applicable rate schedule.

June 1, 2019 through May 31, 2020 and June 1, 2020 through May 31, 2021

		Application Period			
Wattage	Nominal kWh Energy Usage per Unit per Month	06/01/2019 through 11/30/2019	12/01/2019 through 05/31/2020	06/01/2020 through 11/30/2020	12/01/2020 through 05/31/2021
Supply Charge ¢ per kWh		X.XXXX	X.XXXX	X.XXXX	X.XXXX
		Fixture Charge — $ per Month			
Mercury Vapor					
100	44	X.XXXX	X.XXXX	X.XX	X.XX
175	74	X.XXXX	X.XXXX	X.XX	X.XX
250	102	X.XXXX	X.XXXX	X.XX	X.XX
400	161	X.XXXX	X.XXXX	X.XX	X.XX
1000	386	X.XXXX	X.XXXX	X.XX	X.XX
High Pressure Sodium					
70	29	X.XXXX	X.XXXX	X.XX	X.XX
100	50	X.XXXX	X.XXXX	X.XX	X.XX
150	71	X.XXXX	X.XXXX	X.XX	X.XX
200	95	X.XXXX	X.XXXX	X.XX	X.XX
250	110	X.XXXX	X.XXXX	X.XX	X.XX
400	170	X.XXXX	X.XXXX	X.XX	X.XX
1000	387	X.XXXX	X.XXXX	X.XX	X.XX
Flood Lighting - Unmetered					
70	29	X.XXXX	X.XXXX	X.XX	X.XX
100	46	X.XXXX	X.XXXX	X.XX	X.XX
150	67	X.XXXX	X.XXXX	X.XX	X.XX
250	100	X.XXXX	X.XXXX	X.XX	X.XX
400	155	X.XXXX	X.XXXX	X.XX	X.XX
Light-Emitting Diode (LED) — Cobra Head (C)					
~~43~~	~~15~~	~~X.XXXX~~	~~X.XXXX~~	~~X.XX~~	~~X.XX~~
~~106~~	~~37~~	~~X.XXXX~~	~~X.XXXX~~	~~X.XX~~	~~X.XX~~
45	16	X.XX	X.XX	X.XX	X.XX
60	21	X.XX	X.XX	X.XX	X.XX
95	34	X.XX	X.XX	X.XX	X.XX
139	49	X.XX	X.XX	X.XX	X.XX
219	77	X.XX	X.XX	X.XX	X.XX
275	97	X.XX	X.XX	X.XX	X.XX
Light-Emitting Diode (LED) — Colonial (C)					
48	17	X.XX	X.XX	X.XX	X.XX
83	29	X.XX	X.XX	X.XX	X.XX
Light-Emitting Diode (LED) — Contemporary (C)					
47	17	X.XX	X.XX	X.XX	X.XX
62	22	X.XX	X.XX	X.XX	X.XX

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 8 – DEFAULT SERVICE SUPPLY – (Continued)

(Applicable to Rate Schedules RS, RH, RA, GS/GM, GMH, AL, SE, SM, SH, UMS and PAL)

CONTINGENCY PLAN

In the event Duquesne receives bids for less than all Tranches or the Commission does not approve all or some of the submitted bids or in the event of supplier default, then Duquesne will provide the balance of the default supply for commercial and industrial customers through purchases in the PJM spot markets until such time that a different contingency plan is approved by the Commission. Duquesne will submit to the Commission within fifteen (15) days after any such occurrence an emergency plan to handle any default service shortfall. All costs associated with implementing the contingency plan will be included as part of the DSS described in the section below, "Calculation of Rate."

CALCULATION OF RATE

DSS rates shall be determined based on the formula described in this section. The DSS shall be filed with the Commission no less than sixty (60) days prior to the start of the next Application Period as defined under the Default Service Supply Rate section of this Rider. Rates are reconciled on a semi-annual basis in accordance with the Default Service Supply Rate section of this Rider. The rates shall include an adjustment to reconcile revenue and expense for each Application Period. The DSS shall be determined to the nearest one-thousandth of one (1) mill per kilowatt-hour in accordance with the formula set forth below and shall be applied to all kilowatt-hours billed for default service provided during the billing month:

$$DSS = [(RFP + SLR + (DSS_a + E))/S) * F] * [1/(1 - T)]$$

Where:

DSS = Default Service Supply rate, converted to cents per kilowatt-hour, to be applied to each kilowatt-hour supplied to customers taking default service from the Company under this Rider.

RFP = The weighted average of the winning bids received in a competitive request for proposal for each customer class identified above and described in the "Default Service Supply Rate" section and adjusted for customer class transmission and distribution line losses. The request for proposal shall be conducted as described in "Procurement Process."

DSSa = The total estimated direct and indirect costs incurred by the Company to acquire DSS from any source on behalf of customers described above in the "Procurement Process." The Application Period shall be for each period over which the DSS, as computed, will apply. Projections of the Company's costs to acquire default supply for the Application Period shall include all direct and indirect costs of generation supply to be acquired by the Company from any source plus any associated default service supply-related procurement and administration costs. Company costs may also include the expenses to support time-of-use ("TOU") programs offered by EGSs. Time-of-use expenses will be assigned to the applicable customer class for recovery through this Rider. Default service supply-related costs shall include the cost of preparing the company's default service plan filing and working capital costs associated with default service supply. The Company will recover these costs over the default service plan period as defined (C)
in the Commission's order at Docket No. ~~P-2016-2543140~~R-2018-3000124.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 9 – DAY-AHEAD HOURLY PRICE SERVICE – (Continued)

(Applicable to Rates GL, GLH, L and HVPS and Generating Station Service)

MONTHLY CHARGES – (Continued)

PJM Ancillary Service Charges and Other PJM Charges – (Continued)

PJM_S= PJM Surcharge is a pass-through of the charges incurred by the Company for grid management and administrative costs associated with membership and operation in PJM. These are the charges incurred by the Company under PJM Schedules 9 and 10 to provide hourly price service.

R_D = Reactive supply service charge in $/MW-day to serve the customer's load as calculated under the PJM Tariff Schedule 2.

B_D = Blackstart service charge in $/MW-day to serve the customer's load as calculated under the PJM Tariff Schedule 6A.

Fixed Retail Administrative Charge

FRA = The Fixed Retail Administrative Charge in $ per MWH. The Fixed Retail Administrative Charge consists of the sum of administrative charges for the suppliers providing hourly price service (as determined by a competitive solicitation process) and for the Company to obtain supply and administer this service. Default service supply-related costs shall include the cost of preparing the company's default service plan filing and working capital costs associated with default service supply. The Company will recover these costs over the default service plan period as defined in the Commission's order at Docket No. ~~P-2016-2543140~~R-2018-3000124. (C) (C)

The supplier charges shall be based on the winning bids in the Company's most recent solicitation for supply of hourly price default service.

The Company's administrative charges shall be based on an amortization of the costs incurred by the Company to acquire generation supply from any source for the Large C&I Customer Class during the most recent twelve-month (12-month) period ended May 31st (as determined by amortizing such costs over a 12-month period) plus the amortization of the cost of administering the hourly price service over the duration of the default service plan, including any unbundled costs of preparing the Company's default service plan filing and working capital costs associated with default service supply.

This charge shall also include the Company's costs associated with any Commission approved solar contracts and its administration, if applicable, in $ per MWh. The proceeds of any solar energy, capacity, ancillary services and solar AECs that are acquired and in excess of those allocated to default service suppliers, and sold into the market, will be netted against solar contract costs.

Application Period	FRA $/MWH
June 1, 2017 through May 31, 2018	$1.77
June 1, 2018 through May 31, 2019	$1.74
June 1, 2019 through May 31, 2020	$X.XX
June 1, 2020 through May 31, 2021	$X.XX

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 10 - STATE TAX ADJUSTMENT

(Applicable to All Rates)

In addition to the charges provided in this Tariff, a two-part surcharge will apply to all bills rendered by the Company, 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.

Part 1 of the surcharge, at a rate of ~~(0.1276%)~~0.0000% will include Capital Stock Tax, Corporate Net Income Tax, and Public Utility Realty Tax, which will be applied to the distribution charges of customer bills. (D)

Part 2 of the surcharge, at a rate of 0.0000% will include Gross Receipts Tax and will be applied to all portions of customer bills.

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 December 22, 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.

(D) – Indicates Decrease

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 13 - GENERAL SERVICE SEPARATELY METERED ELECTRIC SPACE HEATING SERVICE

(Applicable to Rate GS/GM)

AVAILABILITY

Available for separately metered circuitry connected to electric space heating devices limited to electric resistance heaters, add-on heat pumps, heat pump compressors, system fans, pumps and controls except where the customer uses the Company's service for water heating, then water heating may also be included on the circuit. The space heating service may be provided at the same voltage as other electric service.

MONTHLY RATE

ENERGY CHARGES

For the billing months of November through April, all kilowatt-hours will be billed the applicable kilowatt-hour Monthly Energy Charges of Rate GS/GM. The applicable Monthly Energy Charge will be determined based on the customer's monthly ~~metered~~ demand, including the demand associated with the separately metered electric space heating, as described in the Electric Charges section of Rate GS/GM. Customers who purchase their electric supply requirements from the Company will be billed the applicable transmission energy charges of Appendix A and the applicable energy charges of Rider No. 8 – Default Service Supply. For the billing months of May through October, Rate GS/GM will apply. (C)

METER CHARGE.. $13.21 per month

The customer will be responsible for any necessary wiring, structural or equipment changes or relocations to allow the isolation and metering of the electric space heating system.

(C) – Indicates Change

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES

(Applicable to GM < 25, GM ≥ 25, GMH < 25, GMH ≥ 25, GL, GLH and L ~~all General Service~~ Rates ~~Except Non-Demand Metered GS/GM Customers~~) (C)

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

A. DEFINITIONS

Supplementary ~~Power~~ Service is ~~electric energy and capacity supplied~~ distribution services provided by the Company ~~or by an Electric Generation Supplier (EGS)~~ to a non-utility generating facility and regularly used in addition to that electric energy which the non-utility generating facility generates itself. The Company's regular and appropriate General Service Rates will be utilized for billing for Supplementary ~~Power~~Service. ~~Customers purchasing Supplementary Power from an EGS will be billed for charges according to their applicable rate and billing arrangement with their EGS.~~ (C) (C) (C)

Back-Up ~~Power~~ Service is ~~electric energy and capacity supplied~~ distribution services provided by the Company to a non-utility generating facility during any outage of the non-utility generating facility's electric generating equipment or otherwise, to replace electric energy ordinarily generated by the non-utility generating facility's generating equipment. (C) (C)

Base Period is the twelve consecutive monthly billing periods applicable to the customer ending one month prior to the installation of new on-site generation or increase in capacity to existing on-site supply.

Contract Demand is the maximum electrical capacity in kilowatts that the Company shall be required by the contract to deliver to the customer for Back-Up ~~Power~~Service. A Contract Demand may be established for Supplementary ~~Power~~ Serviceto the customer's facility. (C) (C)

Supplementary ~~Power~~ Service Billing Determinants ~~are the monthly billing period billing demand in kilowatts (kW) and the energy usage in kilowatt-hours (kWh) for~~ is the kW specified in the Contract with the customer for Supplementary ~~Power~~ Service~~during the current billing month under which the on-site generation is operable. The Supplementary Power kW shall not exceed the Contract Demand kW for Supplementary Power, if applicable~~. (C) (C) (C)

Back-Up ~~Power~~ Service Billing Determinants ~~are the monthly billing period billing demand in kilowatts (kW) and energy usage (kWh) in excess of those provided as Supplementary Power. If a Contract Demand exists for Supplementary Power, the~~ is the kW specified in the Contract with the customer for Back-Up ~~Billing Determinants~~ Service~~are the kW and kWh in excess of the Supplementary Power Contract Demand~~. (C) (C) (C) (C)

Distribution Base Period Billing Determinants are the billing demand (kW) ~~and the energy usage (kWh)~~ for the month in the Base Period corresponding to the current billing month under which the on-site generation is operable. For new customers, the Company will use existing procedures to estimate Base Period Billing Determinants. (C)

Supply Billing Determinants for customers not being served by an electric Generation Supplier (EGS), ~~on~~ Rate Schedules GL, GLH, and L ~~and HVPS are the billing demand (kW) and energy usage (kWh) during~~ shall be the billing determinates for the current billing month then in effect under Rider No. 9 – Day-Ahead Hourly Price Service. Supply Billing Determinants for customers on Rate Schedule GS/GM and GMH shall be the ~~same as those defined above for Distribution~~ billing determinants for the current billing month then in effect under Rider No. 8 – Default Service Supply. (C) (C) (C) (C) (C)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 16 - SERVICE TO NON-UTILITY GENERATING FACILITIES - (Continued)

(Applicable to GM < 25, GM ≥ 25, GMH < 25, GMH ≥ 25, GL, GLH and L ~~all General Service~~ Rates) (C)

B. BACK-UP ~~POWER~~SERVICE (C)

The Company will supply ~~such~~ Back-Up ~~s~~Service ~~each month~~ at the following rates: (C)

DISTRIBUTION

A distribution charge of ~~$2.50~~ $8.00 per kW shall be applied to the Back-Up ~~Power~~ Service Billing Determinants ~~for Back-Up Power~~. (I)(C) (C)

The distribution charges will be applied in each month based on the customer's Contract Demand without regard to actual usage~~whether or not back-up energy is supplied~~. (C)

~~**SUPPLY**~~ (C)

~~In any month that the Company provides energy to back up the customer's equipment, supply service shall be supplied and billed under Rider No. 9 for customers with Contract Demand of 300 kW or more. For customers having Contract Demand of less than 300 kW, the Company will bill the applicable supply demand and energy charges then in effect under Rate Schedule GS/GM.~~

If actual usage of Back-Up Service exceeds zero for more than 15% of the hours in any Base Period, then those hours above the 15% threshold will be counted toward the billing on the customer's ~~The use of 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 rate~~s~~, including all ratchets applicable. (C) (C) (C)

If a customer's Back-Up Service requirement at any time ~~actual kW demand at the time back-up is being supplied~~ exceeds the customer's B~~b~~ack-U~~u~~p Contract Demand by 5% or more, the actual Back-Up Service requirement measured in kW demand ~~as established~~ will become the customer's new B~~b~~ack-U~~u~~p Contract Demand for the remaining term of the back-up contract. If a customer's actual ~~kW demand at the time b~~Back-~~u~~Up ~~s~~Service requirement at any time ~~is being supplied~~ exceeds the customer's B~~b~~ack-~~u~~Up Contract Demand by 10% or more, the customer will be assessed a fee equal to ~~determined by~~ the difference between the actual ~~demand established when b~~Back-~~u~~Up ~~s~~Service requirement at the time ~~is being supplied~~ and the ~~b~~Back-~~u~~Up Contract Demand multiplied by two times the applicable charge per kilowatt. (C) (C) (C) (C) (C) (C) (C)

SUPPLY (C)

In any month that the Company provides energy to back up the customer's equipment, supply service shall be supplied and billed under Rider No. 9 for customers with Contract Demand of 300 kW or more. For customers having Contract Demand of less than 300 kW, the Company will bill the applicable supply demand and energy charges then in effect under Rate Schedule GS/GM.

C. INTERCONNECTION

Each non-utility generating facility will be required to install at its expense or pay in advance to have the Company 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 the Company's General Service Rates, except as noted below. Any such equipment to be installed by the non-utility generating facility must be reviewed and approved in writing by the Company prior to installation. Nothing in this Rider shall exempt a new customer from the application of Rule No. 7 and Rule No. 9 regarding Supply Line Extensions and Relocation of Facilities.

However, customers may elect to pay the cost of existing or newly required transformation equipment that is over and above that equipment necessary for the Company to supply the customer with its contracted Supplemental ~~Power~~ Service via a monthly charge rather than in total at the onset of the contract. The monthly charge for transformation equipment for customers with contract demand under this rider of 5,000 kW or more will be determined by the Company on a case-by-case basis~~. For all others, the rate of $0.2523 per kW per month will apply.~~ (C) (C)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 20 – SMART METER CHARGE

(Applicable to Rates RS, RH, RA, GS/GM, GMH, GL, GLH, L, HVPS and AL)

PURPOSE

The Smart Meter Charge ("SMC") is instituted as a cost recovery mechanism to recover all costs to implement the Company's Smart Meter Procurement and Implementation Plan ("Plan"). The SMC has been added per Commission Order at Docket No. M-2009-2123948. Act 129 ("Act") became effective November 14, 2008, requiring all Pennsylvania electric distribution companies ("EDCs") with more than 100,000 customers to implement smart meters. Act 129 set forth the timeline for implementation, the definition of smart meters and the provisions for full and current cost recovery of all costs incurred by EDCs to install and make fully functional a smart meter system defined in and required by Act 129. The Company filed its Plan on August 14, 2009, in compliance with the Act, including this Charge and provisions for cost recovery. This Charge shall be updated as described below to recover all costs associated with implementing the Plan.

The SMC is a non-bypassable charge and shall be applicable to the monthly bill of all metered customers based on the number of meters installed at the premise.

ELIGIBLE COSTS

The SMC recovers all eligible costs incurred by the Company to implement smart meter technology and the supporting infrastructure. Eligible costs, described in 66 Pa. C.S. § 2807(f), include capital and expense items relating to all Plan elements, equipment and facilities, as well as all related administrative costs. Plan costs include, but are not limited to, capital expenditures for any equipment and facilities that may be required to implement the Plan, as well as depreciation, operating and maintenance expenses, a return component based on the EDC's weighted cost of capital and taxes. In general, eligible administrative costs include, but are not limited to, incremental costs relating to Plan development, cost analysis, measurement and verification and reporting. The costs associated with testing, upgrades, maintenance and personnel training are considered eligible costs.

MONTHLY SMART METER CHARGE

Meter Type	Monthly Charge Per Meter	
Single-Phase	~~$4.24~~$0.00	(D)
Poly-Phase	~~$6.29~~$0.00	(D)

The SMC, calculated independently for each meter type, shall be applied to all applicable customers served under the Tariff. Customers will be billed based on the number of meter types installed at their premise. Customers with multiple meters will incur multiple charges. The SMC shall be determined in dollars and cents per month per meter in accordance with the formula described in the "Calculation of Charge" section and shall be applied to all applicable customers served during any part of a billing month.

(D) – Indicates Decrease

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 21 – NET METERING SERVICE

(Applicable to Rates RS, RH, RA, GS/GM, GMH and GL)

PURPOSE

This Rider sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY

This Rider applies to renewable customer-generators served under Rate Schedules RS, RH, RA, GS/GM, GMH and GL who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rider is available to installations where any portion of the electricity generated by the renewable energy generating system offsets part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate RS, RH or RA) or not larger than 3,000 kilowatts at other customer service locations (Rate GS/GM, GMH and GL), except for Customers whose systems are above three megawatts and up to five megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a micro grid is in place for the primary or secondary purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers ("IEEE") and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rider is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rider is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule RS, RH, RA, GS/GM, GMH and GL.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter, ~~that~~ which can measure and record the flow of electricity in both directions at the same rate, for all billing-related purposes, including measurement of customer-generator's net electricity consumption. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense. Except for those customer-generator facilities interconnected, or for which the Company has received a completed Part 1 Interconnection Application, prior to January 1, 2019, such facility shall also be equipped with an additional meter (the "generation meter"), which shall be installed at Company expense and which shall be used to record outbound flow of electricity. (C) (C) (C)

STANDARD CONTRACT RIDERS - (Continued)

RIDER NO. 22 – DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

(Applicable to All Rates)

In addition to the net charges provided for in this Tariff, a charge of ~~3.77%~~0.00% ~~(three point seven seven percent)~~ will apply consistent with the Commission Order entered September 15, 2016, at Docket No. P-2016-2540046 approving the Distribution System Improvement Charge ("DSIC"). (D)

GENERAL DESCRIPTION

PURPOSE

To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

ELIGIBLE PROPERTY

The DSIC-eligible property will consist of the following:

— Poles and towers (account 364);

— Overhead conductors (account 365) and underground conduit and conductors (accounts 366 and 367);

— Line transformers (account 368) and substation equipment (account 362);

— Any fixture or device related to eligible property listed above including insulators, circuit breakers, fuses, reclosers, grounding wires, cross arms and brackets, relays, capacitors, converters and condensers;

— Unreimbursed costs related to highway relocation projects where an electric distribution company must relocate its facilities; and

— Other related capitalized costs.

EFFECTIVE DATE

The DSIC will become effective October 1, 2016.

(D) – Indicates Decrease

APPENDIX A – (Continued)

TRANSMISSION SERVICE CHARGES – (Continued)

(Applicable to All Rates)

MONTHLY RATES – (Continued)

Rate Class	Energy Charge $/kWh	Demand Charge $/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture	Monthly Charge Per Fixture	
			Rate Class			
By Wattage			**SH**	**PAL**	**SM**	
Flood Lighting - Unmetered						
70			—	$0.18	—	
100			—	$0.29	—	
150			—	$0.42	—	
250			—	$0.63	—	
400			—	$0.98	—	
Light-Emitting Diode (LED) — Cobra Head						(C)
~~43~~			—	—	~~$0.09~~	(C)
~~106~~			—	—	~~$0.23~~	(C)
45			—	$0.00	$0.00	
60			$0.00	$0.00	$0.00	
95			$0.00	$0.00	$0.00	
139			$0.00	$0.00	$0.00	
219			$0.00	$0.00	$0.00	
275			—	$0.00	$0.00	
Light-Emitting Diode (LED) — Colonial						(C)
48			—	$0.00	$0.00	
83			—	$0.00	$0.00	
Light-Emitting Diode (LED) — Contemporary						(C)
47			—	$0.00	$0.00	
62			—	$0.00	$0.00	

BILLING DEMAND

Billing Demand subject to Transmission Service Charges for customers taking service under Rate Schedules GS/GM and GMH shall be the same as that determined for distribution and supply charges under the applicable rate schedules.

Billing Demand subject to Transmission Service Charges for Customers taking service under Rate Schedules GL, GLH, L, HVPS and UMS shall be the customer's daily network service coincident peak load contribution in MW. This quantity is determined based on the customer's load coincident with the annual peak of the Duquesne Zone (single coincident peak) as defined in the PJM Tariff Section 34.1.

ANNUAL UPDATE

The Transmission Service Charges (TSC) defined herein will be updated effective June 1st of each calendar year or more often upon determination that the rates then in effect would result in a significant over or under collection. On or about May 1st, the Company will file revised TSC rates with the PA Public Utility Commission (Commission) defining rates in effect from June 1 to May 31 of the following year, the computation year. These rates shall be determined based on the projected revenue requirement for the computation year, the projected cost of PJM charges and the over or under collection of expenses based on actual TSC revenue and expense incurred up to March 1 of each filing year. The revenue requirement and over or under collection shall be allocated to each rate class based on the class contribution to the Company's coincident peak load (1CP) and Default Service share of the 1CP load from the previous calendar year. The costs for ancillary services and PJM administrative expenses are included in the Default Service Supply rates defined in Rider No. 8. The costs for ancillary services and PJM administrative expenses for rate classes GL, GLH, L and HVPS will be billed in accordance with Rider No. 9. The rates applicable to each Rate Schedule shall be determined in accordance with the following formulas.

(C) – Indicates Change

Exhibit No. DBO-3

Duquesne Light Company

Digest of Proposed Changes
contained in
Tariff Electric – PA. P.U.C. No. 24
Supplement No. 174

Docket No. R-2018-3000124

March 28, 2018

Table of Contents

I. General

Duquesne Light Company's Supplement No. 174 to Tariff Electric – PA. P.U.C. No. 24 issued March 28, 2018, to become effective May 29, 2018, results in an overall average increase of 16.1% in distribution revenues and is expected to produce $81.6 million of additional annual distribution revenue under future test year conditions.

All customers will be notified of the proposed rate increase by a news release issued the day of the filing, newspaper advertisements in major service territory newspapers the day of the filing and by a bill insert to be mailed to all customers during the month after the filing is made.

Other modifications to the rules, rates and riders of Duquesne's tariff are being proposed and, together with a presentation of the proposed and current rates, are discussed below.

II. Proposed Changes to the Table of Contents

List of Modifications — Page Nos. 2A through 2R were added to the Table of Contents.

Rate SM – Street Lighting Municipal — Original Page No. 70A was added to the Table of Contents.

Rate SH – Street Lighting Highway — Original Page No. 73A was added to the Table of Contents.

Rate PAL – Private Area Lighting — Original Page No. 78A was added to the Table of Contents.

Rider No. 4 – Budget Billing HUD Finance Multi-Family Housing (Page No. 83) has been removed from the Table of Contents and revised to read "This Page Intentionally Left Blank."

Rider No. 7 – SECA Charge (Page No. 87) has been removed from the Table of Contents and revised to read "This Page Intentionally Left Blank."

III. Proposed Changes to Tariff Rules

Rule No. 2.1 Rules and Regulations has been added to clarify tariff applicability to all persons taking service.

Rule No. 2.2 Statement by Agents has been added to clarify that Company representatives cannot modify tariff obligations.

III. Proposed Changes to Tariff Rules – (Continued)

Rule No. 3 Application has been revised to update and define the Company's standard nominal service delivery voltages for installations prior to and effective on January 1, 2019.

Rule No. 3.1 Definitions

Due to the addition of Rule No. 2.1 and Rule No. 2.2 and the language modifications to Rule No. 3, language on the pages has been repaginated.

Language has been revised in Definition (8) Customer to clarify the definition of "Customer."

Currently existing definitions for Rate Ready and Renewable Resource have been moved down to place in alphabetical order.

The definition for Summary Billing has been added.

Definitions have been renumbered to place in alphabetical order and to accommodate the addition of a definition of Summary Billing.

Rule No. 4 Contracts

Language has been inserted at the end of the first sentence of paragraph one to clarify that Nonstandard Service costs can be recoverable through special rate contracts.

Language has been revised to adjust instances where the Company can enter into special rate contracts and the duration of special contracts.

Due to the deletion of Second Revised Page No. 9A, Cancelling First Revised Page No. 9A in Supplement No. 72, language has been moved to Fourth Revised Page No. 9, Cancelling Third Revised Page No. 9.

Rule No. 5 Deposits and Advance Payments

Language has been inserted to clarify that EGS charges, where applicable, are included in the calculation of a security deposit.

Language has been inserted to clarify how the Company evaluates creditworthiness of non-residential customers.

Language has been inserted to clarify the Company process for requiring security deposits from non-residential customers.

III. Proposed Changes to Tariff Rules – (Continued)

Rule No. 5 Deposits and Advance Payments – (Continued)

The paragraph referencing "seasonal service" has been removed as obsolete. The Company no longer provides a separate seasonal service rate.

Language has been inserted to explain that security deposit requirements for residential customers do not extend to non-residential accounts.

Rule No. 5a Payment of Outstanding Balance

Language has been inserted to clarify customer/applicant responsibility for outstanding account balances and the documentation required to establish service.

Rule No. 6 Installation Rules

Language has been inserted to clarify limited exception for Company-approved Nonstandard Service.

Rule No. 6.1 Service Point

Rule No. 6.1 Service Point has been added to comply with 52 Pa. Code § 57.28 (a) Electric Safety Standards (Docket No. L-2015-2500632).

Due to the addition of Rule No. 6.1, language on the pages has been repaginated.

Rule No. 7 Supply Line Extensions

Due to the addition of Rule No. 6.1, language on the pages has been repaginated and Original Page No. 11A has been added.

Language has been inserted in Rule No. 7 Supply Line Extensions, B. Overhead Areas (1) to provide additional customer clarity in regard to the length of single-phase, lower-voltage supply line extensions.

Rule No. 7 Supply Line Extensions, B. Overhead Areas (3) has been removed to clarify the Company's ability to recover costs of Nonstandard Service.

Rule No. 7 Supply Line Extensions, C. Underground Areas (3) has been removed to clarify the Company's ability to recover costs of Nonstandard Service.

III. Proposed Changes to Tariff Rules – (Continued)

Rule No. 7 Supply Line Extensions – (Continued)

Language has been inserted to provide that costs other than those associated with service line extensions may be included in a revenue guarantee.

Language has been inserted into Rule No. 7 Supply Line Extensions, E. Revenue Guarantees (2) to clarify the revenue guarantee payment and refund process.

Rule No. 8 Nonstandard Service

Rule No. 8 Connection Charges as shown on First Revised Page No. 15, Cancelling Original Page No. 15 in Supplement No. 2, has been renamed to Rule No. 8 Nonstandard Service in Supplement No. 174.

Language has been revised and inserted to clarify the Company's ability to recover costs of Nonstandard Service.

Rule No. 9 Relocation of Facilities

Due to the revisions to Rule No. 8, language on the pages has been repaginated and Original Page No. 15A has been added.

Rule No. 14.2 Customer Request for Special Metering

Language has been removed as obsolete.

Rule No. 14.3 Sub-Metering

Rule No. 14.3 Sub-Metering has been removed as unnecessary.

Rule No. 18 Redistribution

Language has been modified for clarity.

Rule No. 20.2 Summary Billing

Rule No. 20.2 Summary Billing has been added to explain the availability of Summary Bills to qualifying customers.

Bills and Net Payment Periods

Due to the addition of a new Rule No. 20.2 Summary Billing, currently effective rules have been renumbered and language on the pages has been repaginated.

III. Proposed Changes to Tariff Rules – (Continued)

Rule No. 20.4 Budget Payment Plan for Residential Customers

Language has been inserted to clarify budget billing for customers of bill-ready EGSs.

Rule No. 22 Access to Premises

Language has been inserted to ensure Company access to facilities, particularly in the event of emergency, and to clarify that failure to provide access is grounds for termination.

Rule No. 22.1 Vegetation Management and Right-of-Way

Rule No. 22.1 Vegetation Management and Right-Of-Way has been added to clarify customer and Company responsibilities regarding vegetation management around Company facilities.

Company Property on Customer's Premises

Due to the addition of Rule No. 22.1, language on the pages has been repaginated.

Discontinuance, Curtailment or Interruption of Electric Service

The "Bills and Net Payment Periods – (Continued)" heading has been removed as it is not applicable to the section.

Rule No. 27.1 Death of A Residential Customer

Rule No. 27.1 Death of A Residential Customer has been added to clarify the Company's process for ending service in the name(s) of customers reported as deceased.

Rule No. 33 Inaccessibility

Language has been revised and inserted to clarify that failure to provide Company representatives access to Company facilities is grounds for termination, consistent with Rule No. 22.

Rule No. 46 Provision of Load Data

Language has been modified to reflect current business practice. Rule No. 46 has been revised to comply with Commission Order dated October 11, 2012, at Docket No. R-2012-2320394. The reference to "once each calendar year" has been updated to "five (5) requests in a calendar year."

IV. Proposed Changes to Tariff Rate Schedules

Rate RS – Residential Service

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$9.99	$16.25
All kWh	$/kWh	$0.046994	$0.061147

Rate RH – Residential Service Heating

	Distribution		Current Rates with STAS	Proposed Rates with STAS
	Customer Charge		$9.99	$16.25
Summer:	All kWh	$/kWh	$0.046994	$0.061147
Winter:	All kWh	$/kWh	$0.035696	$0.046451

Rate RA – Residential Service Add-on Heat Pump

	Distribution		Current Rates with STAS	Proposed Rates with STAS
	Customer Charge		$9.99	$16.25
Summer:	All kWh	$/kWh	$0.046994	$0.061147
Winter:	All kWh	$/kWh	$0.011477	$0.015485

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate GS/GM – General Service Small and Medium

Non-Demand – Rate GS

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		\$9.99	\$16.25
All kWh	\$/kWh	\$0.056641	\$0.072821

Demand - Rate GM < 25

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		\$41.95	\$56.00
Demand over 5 kW	\$/kW	\$5.59	\$7.09
All kWh	\$/kWh	\$0.011047	\$0.015123

Demand - Rate GM ≥ 25

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		\$53.93	\$67.00
Demand over 5 kW	\$/kW	\$5.57	\$7.09
All kWh	\$/kWh	\$0.009352	\$0.009381

The design of the Monthly Rate section, including sub-section titling, has been modified for customer clarity.

Language has been modified to clarify customer rate assignments among Rate GS, Rate GM < 25 kW and Rate GM ≥ 25 kW.

Due to the language modifications, language on the Rate Schedule pages has been repaginated.

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate GMH – General Service Medium Heating

	Distribution		Current Rates with STAS	Proposed Rates with STAS
	Customer Charge		$41.95	$56.00
Summer:				
	Demand over 5 kW	$/kW	$5.59	$7.09
	All kWh	$/kWh	$0.011047	$0.015123
Winter:				
	All kWh	$/kWh	$0.024684	$0.031725

The design of the Monthly Rate section has been modified for customer clarity.

Language has been modified to clarify customer rate assignments between Rate GM < 25 kW and Rate GM ≥ 25 kW.

Rate GL – General Service Large

Distribution	Current Rates with STAS	Proposed Rates with STAS
First 300 kW or less	$2,696.55	$3,000.00
Additional kW	$8.08	$9.66

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate GLH – General Service Large Heating

	Distribution		Current Rates with STAS	Proposed Rates with STAS
	Customer Charge		$49.94	$67.00
Summer:				
	First 300 kW or less		$2,696.55	$3,000.00
	Additional kW		$8.08	$9.66
Winter:				
	All kWh	$/kWh	$0.019883	$0.024828

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Rate L – Large Power Service

Service Voltage Less than 138 kV:

Distribution		Current Rates with STAS	Proposed Rates with STAS
First 5,000 kW or less		$34,855.47	$48,500.00
Additional kW	$/kW	$10.95	$11.50

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Language and relevant rate charges have been removed as "Service Voltage 138 kV and Greater" is no longer applicable to Rate L – Large Power Service.

Language has been modified from "his" to "its."

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate HVPS – High Voltage Power Service

Distribution		Current Rates with STAS	Proposed Rates with STAS
Up to and Including 50,000 kW Billing Demand			
	$/kW	$7,731.27	$7,482.78
50,001 kW to 100,000 kW Billing Demand			
	$/kW	$12,076.77	$11,688.61
Greater than 100,000 kW Billing Demand			
	$/kW	$17,126.73	$16,576.26

Language has been modified to correct the name of Rider No. 9 to "Day-Ahead Hourly Price Service."

Language has been modified to lower the kilowatts from "greater than 30,000" to "greater than "5,000" in order to move Rate L – Large Power Service 138 kV and Greater customers to Rate HVPS – High Voltage Power Service.

Language has been modified from "his" to "its."

Rate AL – Architectural Lighting Service

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$6.88	$8.00
Demand all kW	$/kW	$1.29	$1.59
All kWh	$/kWh	$0.001815	$0.002110

Item No. 5 under the "Special Terms and Conditions" section has been removed as the Company no longer provides a separate seasonal service rate.

Rate SE – Street Lighting Energy

Distribution	Current Rates with STAS	Proposed Rates with STAS
Customer Charge	$2.78	$2.91

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate SM – Street Lighting Municipal

Distribution		Current Rates with STAS	Proposed Rates with STAS
Company Owned and Maintained Equipment			
Mercury Vapor:			
100 watt	per month	$12.08	$12.69
175 watt	per month	$12.33	$12.95
250 watt	per month	$12.57	$13.20
400 watt	per month	$13.07	$13.73
1000 watt	per month	$15.04	$15.79
Sodium Vapor:			
70 watt	per month	$12.48	$13.11
100 watt	per month	$12.58	$13.21
150 watt	per month	$12.76	$13.40
250 watt	per month	$13.09	$13.75
400 watt	per month	$13.62	$14.30
1000 watt	per month	$15.66	$16.44
Light-Emitting Diode (LED) – Cobra Head:			
43 watt	per month	$11.16	$0.00
106 watt	per month	$12.82	$0.00
45 watt	per month	$0.00	$13.01
60 watt	per month	$0.00	$13.52
95 watt	per month	$0.00	$13.99
139 watt	per month	$0.00	$15.08
219 watt	per month	$0.00	$17.54
275 watt	per month	$0.00	$19.24
Light-Emitting Diode (LED) – Colonial:			
48 watt	per month	$0.00	$12.18
83 watt	per month	$0.00	$12.18
Light-Emitting Diode (LED) – Contemporary:			
47 watt	per month	$0.00	$14.19
62 watt	per month	$0.00	$14.19
Poles	per month	$9.83	$10.32
Customer Owned and Maintained Equipment			
Distribution Charge per Unit		$0.00	$2.71

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate SM – Street Lighting Municipal – (Continued)

Language has been inserted to reflect the availability of service and/or replacement of mercury vapor lamps, fixtures or luminaries, including brackets and ballasts, beginning January 1, 2019.

Language has been inserted as to the minimum number of LED lights per customer, per order requirement and the contiguous location requirement when replacing existing lighting.

Language has been inserted as to the maximum LED light installations the Company shall be required to perform annually.

Columns in the Monthly Rate section have been updated to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

Due to the addition of LED lamp wattages, language on the Rate Schedule pages has been repaginated.

The Rate Schedule name in the header has been revised to read "Lighting."

A "Customer Owned and Maintained Equipment Charge" section has been added.

Due to the addition of a "Customer Owned and Maintained Equipment Charge" section, language on the Rate Schedule pages has been repaginated and Original Page No. 70A has been added.

Item No. 5 Non-standard installations has been added under the "Special Terms and Conditions" section.

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate SH – Street Lighting Highway

Distribution		Current Rates with STAS	Proposed Rates with STAS
Company Owned and Maintained Equipment			
Sodium Vapor:			
100 watt	per month	$11.94	$12.54
150 watt	per month	$12.10	$12.71
200 watt	per month	$12.27	$12.89
400 watt	per month	$12.92	$13.57
Light-Emitting Diode (LED) – Cobra Head:			
60 watt	per month	$0.00	$13.52
95 watt	per month	$0.00	$13.99
139 watt	per month	$0.00	$15.08
219 watt	per month	$0.00	$17.54
Customer Owned and Maintained Equipment			
Distribution Charge per Unit		$0.00	$2.71

Columns in the Monthly Rate section have been updated to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

New LED lamp wattages have been inserted as choices for Cobra Head fixtures.

Due to the addition of LED lamp wattages, language on the Rate Schedule pages has been repaginated.

A "Customer Owned and Maintained Equipment Charge" section has been added.

Due to the addition of a "Customer Owned and Maintained Equipment Charge" section, language on the Rate Schedule pages has been repaginated and Original Page No. 73A has been added.

Language has been modified to remove "230/460 volts" in Item No. 2 under the "Special Terms and Conditions" section.

Item No. 9 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate SH – Street Lighting Highway.

Rate UMS – Unmetered Service

Distribution		Current Rates with STAS	Proposed Rates with STAS
Customer Charge		$9.99	$10.00
All kWh	$/kWh	$0.015724	$0.012822

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate PAL – Private Area Lighting

Company Owned and Maintained Equipment

Distribution		Current Rates with STAS	Proposed Rates with STAS
High Pressure Sodium:			
70 watt	per month	$12.48	$13.11
100 watt	per month	$12.58	$13.21
150 watt	per month	$12.76	$13.40
250 watt	per month	$13.09	$13.75
400 watt	per month	$13.62	$14.30
Flood Lighting:			
100 watt	per month	$12.48	$13.11
250 watt	per month	$13.06	$13.72
400 watt	per month	$13.65	$14.33
Light-Emitting Diode (LED) – Cobra Head:			
45 watt	per month	$0.00	$13.01
60 watt	per month	$0.00	$13.52
95 watt	per month	$0.00	$13.99
139 watt	per month	$0.00	$15.08
219 watt	per month	$0.00	$17.54
275 watt	per month	$0.00	$19.24
Light-Emitting Diode (LED) – Colonial:			
48 watt	per month	$0.00	$12.18
83 watt	per month	$0.00	$12.18
Light-Emitting Diode (LED) – Contemporary:			
47 watt	per month	$0.00	$14.19
62 watt	per month	$0.00	$14.19
Poles	per month	$9.83	$10.32
Customer Owned and Maintained Equipment			
Distribution Charge per Unit		$2.78	$2.71

Columns in the Monthly Rate section have been updated and revised to reflect "Minimum" Nominal Lamp Wattage as well as Company Owned and Maintained Equipment and Customer Owned and Maintained Equipment charges.

IV. Proposed Changes to Tariff Rate Schedules – (Continued)

Rate PAL – Private Area Lighting – (Continued)

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures.

Language has been modified to correct the reference from "UMS – Unmetered Service" to "PAL – Private Area Lighting."

Due to the addition of LED lamp wattages, language on the Rate Schedule pages has been repaginated.

A "Customer Owned and Maintained Equipment Charge" section has been added.

Due to the addition of a "Customer Owned and Maintained Equipment Charge" section, language on the Rate Schedule pages has been repaginated and Original Page No. 78A has been added.

Item No. 5 Non-standard installations has been added under the "Special Terms and Conditions" section of Rate PAL – Private Area Lighting.

V. Proposed Changes to Tariff Riders

Rider Matrix

The Rider Matrix has been revised to show the removal of Rider No. 4 – Budget Billing HUD Finance Multi-Family Housing and Rider No. 7 – SECA Charge. The Riders now read "Intentionally Left Blank."

Rider No. 1 – Retail Market Enhancement Surcharge

Rider No. 1 – Retail Market Enhancement Surcharge has been modified to remove the recovery of the Purchase of Receivables ("POR") program discount expense associated with the uncollectible expense of EGS consolidated billings. In accordance with Docket No. P-2016-2543140, the expense is being rolled into and recovered through rate base.

In the "Calculation of Rates" section, reference to Purchase of Receivables ("POR") has been removed from the formula and the definition.

V. Proposed Changes to Tariff Riders – (Continued)

Rider No. 4 – Budget Billing HUD Financed Multi Family Housing

Rider No. 4 – Budget Billing HUD Financed Multi-Family Housing is being removed as obsolete.

Rider No. 5 – Universal Service Charge

Language in the "Calculation of Charge" section has been revised. This language was included in the tariff to address a prior CAP Plus proposal. The Company does not have a CAP Plus plan; therefore, it is appropriate to remove this language.

Language in the "Calculation of Charge" section has been revised. Pursuant to the Company's 2017-2019 Universal Service and Energy Conservation Plan, customers who receive a LIHEAP grant are no longer auto-enrolled in CAP. The elimination of the Company's auto-enrollment program was approved by Commission Order entered March 23, 2017 at Docket Number M-2016-2534323.

The CAP participation level has been reset as per the provisions of Rider No. 5.

Rider No. 7 – SECA Charge

Rider No. 7 – SECA Charge is being removed as the charges are being recovered through the Company's Appendix A – Transmission Service Charges ("TSC").

V. Proposed Changes to Tariff Riders – (Continued)

Rider No. 8 – Default Service Supply

(Rate Schedules SM, SH and PAL)
Lamp wattage as available on applicable rate schedule.

		Application Period				
Wattage	**Nominal kWh Energy Usage per Unit per Month**	**06/01/2017 through 11/30/2017**	**12/01/2017 through 05/31/2018**	**06/01/2018 through 11/30/2018**	**12/01/2018 through 05/31/2019**	**01/01/2019 through 05/31/2019**
Supply Charge ¢ per kWh		3.7939	3.8177	3.6653	X.XXXX	X.XXXX
		Fixture Charge — $ per Month				
Light-Emitting Diode (LED) — Cobra Head						
43	15	0.57	0.57	0.55	X.XX	—
106	37	1.40	1.40	1.36	X.XX	—
45	16	—	—	—	—	X.XX
60	21	—	—	—	—	X.XX
95	34	—	—	—	—	X.XX
139	49	—	—	—	—	X.XX
219	77	—	—	—	—	X.XX
275	97	—	—	—	—	X.XX
Light-Emitting Diode (LED) — Colonial						
48	17	—	—	—	—	X.XX
83	29	—	—	—	—	X.XX
Light-Emitting Diode (LED) — Contemporary						
47	17	—	—	—	—	X.XX
62	22	—	—	—	—	X.XX

Rider No. 8 – Default Service Supply – (Continued)

(Rate Schedules SM, SH and PAL)
Lamp wattage as available on applicable rate schedule.

		Application Period			
Wattage	Nominal kWh Energy Usage per Unit per Month	06/01/2019 through 11/30/2019	12/01/2019 through 05/31/2020	06/01/2020 through 11/30/2020	12/01/2020 through 05/31/2021
Supply Charge ¢ per kWh		X.XXXX	X.XXXX	X.XXXX	X.XXXX
		Fixture Charge — $ per Month			
Light-Emitting Diode (LED) — Cobra Head					
45	16	X.XX	X.XX	X.XX	X.XX
60	21	X.XX	X.XX	X.XX	X.XX
95	34	X.XX	X.XX	X.XX	X.XX
139	49	X.XX	X.XX	X.XX	X.XX
219	77	X.XX	X.XX	X.XX	X.XX
275	97	X.XX	X.XX	X.XX	X.XX
Light-Emitting Diode (LED) — Colonial					
48	17	X.XX	X.XX	X.XX	X.XX
83	29	X.XX	X.XX	X.XX	X.XX
Light-Emitting Diode (LED) — Contemporary					
47	17	X.XX	X.XX	X.XX	X.XX
62	22	X.XX	X.XX	X.XX	X.XX

A new application period is reflected in the heading and added to the chart to reflect the addition of LED lighting for Rate Schedule SM, Rate Schedule SH, and Rate Schedule PAL. Lamp wattage, as available, on applicable rate schedule.

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures, as available, on applicable rate schedule.

In the "Calculation of Rates" section, the Docket No. has been updated in DSSa.

Rider No. 9 – Day-Ahead Hourly Price Service

Under "Fixed Retail Administrative Charge" section, the Docket No. has been updated in FRA.

Rider No. 10 – State Tax Adjustment

Rider No. 10 – State Tax Adjustment has been modified to reflect that Part 1 of the STAS has been set to zero.

Rider No. 13 – General Service Separately Metered Electric Space heating Service

The word "metered" has been removed in the paragraph under "Energy Charges."

V. Proposed Changes to Tariff Riders – (Continued)

Rider No. 16 – Service to Non-Utility Generating Facilities

Language has been revised and inserted to clarify the service being provided and the definition of billing determinates.

The distribution charge applied to the Back-Up Service Billing Determinants has increased.

Rider No. 20 – Smart Meter Charge

Rider No. 20 – Smart Meter Charge has been modified to reflect that it has been set to zero.

Rider No. 21 – Net Metering Service

Language has been revised and inserted to require the installation of a generation meter to measure actual customer-generator facility output to accommodate and plan for increased solar saturation.

Rider No. 22 – Distribution System Improvement Charge

Rider No. 22 – Distribution System Improvement Charge ("DSIC") has been modified to reflect that it has been set to zero.

VII. Appendix A – Transmission Service Charges

Rate Class	Energy Charge $/kWh	Demand Charge $/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture	Monthly Charge Per Fixture
			Rate Class		
					SM
Light-Emitting Diode (LED)					
43					$0.09
106					$0.23

Rate Class	Energy Charge $/kWh	Demand Charge $/kW	Monthly Charge Per Fixture	Monthly Charge Per Fixture	Monthly Charge Per Fixture
			Rate Class		
			SH	PAL	SM
Light-Emitting Diode (LED) – Cobra Head					
45			—	$0.00	$0.00
60			$0.00	$0.00	$0.00
95			$0.00	$0.00	$0.00
139			$0.00	$0.00	$0.00
219			$0.00	$0.00	$0.00
275			—	$0.00	$0.00
Light-Emitting Diode (LED) – Colonial					
48			—	$0.00	$0.00
83			—	$0.00	$0.00
Light-Emitting Diode (LED) – Contemporary					
47			—	$0.00	$0.00
62			—	$0.00	$0.00

Current LED lamp wattages have been removed.

New LED lamp wattages have been inserted as well as choices of Cobra Head, Colonial and Contemporary fixtures, as available, on applicable rate schedule.

Exhibit DBO-4
Duquesne Light Company
LED Street Lighting Service
Rate Summary

		Cobrahead						Colonial LED		Contemporary LED	
Line No	Description	45 Nominal Watts	60 Nominal Watts	95 Nominal Watts	139 Nominal Watts	219 Nominal Watts	275 Nominal Watts	48 Nominal Watts	83 Nominal Watts	47 Nominal Watts	62 Nominal Watts
1	Total Material Cost	$385 02	$433 58	$480 59	$584 22	$822 02	$985 65	$305 00	$305 00	$498 91	$498 91
2	Total Labor Cost	$228 59	$228 59	$228 59	$228 59	$228 59	$228 59	$228 59	$228 59	$228 59	$228 59
3	Total Capitalized Investment	$ 613 61	$ 662 17	$ 709 18	$ 812 81	$ 1,050 61	$ 1,214 24	$ 533 59	$ 533 59	$ 727 50	$ 727 50
4	Revenue Requirement NPV	$735 41	$793 61	$849 95	$974 15	$1,259 15	$1,455 26	$639 51	$639.51	$871 91	$871 91
5	Annualized Levelized Payment	$71 89	$77 58	$83 09	$95 23	$123 09	$142 26	$62 51	$62.51	$85 23	$85 23
6	Monthly Fixture Charge	$ 5 99	$ 6 47	$ 6 92	$ 7 94	$ 10 26	$ 11 86	$ 5 21	$ 5 21	$ 7 10	$ 7 10
7	Gross Receipts Tax	$ 0 38	$ 0 41	$ 0 43	$ 0 50	$ 0 64	$ 0 74	$ 0 33	$ 0 33	$ 0 45	$ 0 45
8	Monthly Fixture Charge	$ 6 37	$ 6 88	$ 7 35	$ 8 44	$ 10 90	$ 12 60	$ 5 54	$ 5.54	$ 7 55	$ 7 55
10	Fixed Distribution Charge (1)	$ 2 71	$ 2 71	$ 2 71	$ 2 71	$ 2 71	$ 2 71	$ 2.71	$ 2.71	$ 2 71	$ 2 71
11	Operating Charge (1)	$ 3 93	$ 3 93	$ 3 93	$ 3 93	$ 3 93	$ 3 93	$ 3 93	$ 3.93	$ 3 93	$ 3 93
12	Total Monthly Charge	$ 13 01	$ 13 52	$ 13 99	$ 15 08	$ 17 54	$ 19 24	$ 12 18	$ 12 18	$ 14 19	$ 14 19

(1) As calculated in Howard Gorman Exhibit 6-11

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
45 W LED Installation

Financial Input	Input
Capital Investment - Material	$385 02
Capitalized Labor	$228 59
Total Capitalized Investment	$613 61

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$735 41
Levelized Annual Revenue Requirement	$71 89
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$71 89
Net Monthly Tariff Rate	$5 99
PA Gross Receipts Tax	$0 38
Total Monthly Distribution Rate	**$6.37**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	Return				Deferred Tax on Depreciation			Tax			Total	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	613 61	12 82	0 00	36 62	49 45	30 68	30 68	0 00	0 00	14 88	14 88	95 01	88 42
2	582 93	12 18	0 00	34 79	46 98	30 68	30 68	0 00	0 00	14 14	14 14	91 79	167 92
3	552 25	11 54	0 00	32 96	44 50	30 68	30 68	0 00	0 00	13 39	13 39	88 58	239 31
4	521 57	10 90	0 00	31 13	42 03	30 68	30 68	0 00	0 00	12 65	12 65	85 36	303 33
5	490 89	10 26	0 00	29 30	39 56	30 68	30 68	0 00	0 00	11 90	11 90	82 14	360 67
6	460 21	9 62	0 00	27 47	37 09	30 68	30 68	0 00	0 00	11 16	11 16	78 93	411 94
7	429 53	8 98	0 00	25 64	34 61	30 68	30 68	0 00	0 00	10 42	10 42	75 71	457 71
8	398 85	8 34	0 00	23 81	32 14	30 68	30 68	0 00	0 00	9 67	9 67	72 49	498 50
9	368 17	7 69	0 00	21 97	29 67	30 68	30 68	0 00	0 00	8 93	8 93	69 28	534 77
10	337 49	7 05	0 00	20 14	27 20	30 68	30 68	0 00	0 00	8 18	8 18	66 06	566 96
11	306 81	6 41	0 00	18 31	24 72	30 68	30 68	0 00	0 00	7 44	7 44	62 84	595 45
12	276 13	5 77	0 00	16 48	22 25	30 68	30 68	0 00	0 00	6 70	6 70	59 63	620 62
13	245 45	5 13	0 00	14 65	19 78	30 68	30 68	0 00	0 00	5 95	5 95	56 41	642 77
14	214 77	4 49	0 00	12 82	17 31	30 68	30 68	0 00	0 00	5 21	5 21	53 20	662 21
15	184 08	3 85	0 00	10 99	14 83	30 68	30 68	0 00	0 00	4 46	4 46	49 98	679 21
16	153 40	3 21	0 00	9 16	12 36	30 68	30 68	0 00	0 00	3 72	3 72	46 76	694 01
17	122 72	2 56	0 00	7 32	9 89	30 68	30 68	0 00	0 00	2 98	2 98	43 55	706 84
18	92 04	1 92	0 00	5 49	7 42	30 68	30 68	0 00	0 00	2 23	2 23	40 33	717 89
19	61 36	1 28	0 00	3 66	4 94	30 68	30 68	0 00	0 00	1 49	1 49	37 11	727 36
20	30 68	0 64	0 00	1 83	2 47	30 68	30 68	0 00	0 00	0 74	0 74	33 90	735 41

PV Tax Shields	313 86
Tax on shields	90 68
Investment	613 61
After Tax Investment	522 93

Adjust for Tax Gross-Up 735.41 <------------------------------ = ------------------------------> PV Rev Req 735.41

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
60 W LED Installation

Financial Input	Input
Capital Investment - Material	$433.58
Capitalized Labor	$228.59
Total Capitalized Investment	$662.17

Years for straight line book depreciation		20
Book Depreciation Rate		5.00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5.00%
Tax Rate	State	9.99%
	Federal	21.00%
	Combined	28.89%
	Gross Revenue Adjustment	71.11%
	Gross Revenue Conversion Factor	1.40631
PA Gross Receipts Tax		5.90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45.49%	4.60%	2.09%	1.49%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	54.51%	10.95%	5.97%	5.97%
	100.00%		8.06%	7.45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$793.61
Levelized Annual Revenue Requirement	$77.58
Annual O&M / Maintenance Expense	$0.00
Annual Revenue Requirement	$77.58
Net Monthly Tariff Rate	$6.47
PA Gross Receipts Tax	$0.41
Total Monthly Distribution Rate	**$6.87**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B.O.Y. Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E.O.Y. Def. Inc. Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	662.17	13.84	0.00	39.52	53.36	33.11	33.11	0.00	0.00	16.06	16.06	102.53	95.42
2	629.07	13.15	0.00	37.55	50.69	33.11	33.11	0.00	0.00	15.26	15.26	99.06	181.20
3	595.96	12.46	0.00	35.57	48.02	33.11	33.11	0.00	0.00	14.45	14.45	95.59	258.25
4	562.85	11.76	0.00	33.59	45.36	33.11	33.11	0.00	0.00	13.65	13.65	92.12	327.34
5	529.74	11.07	0.00	31.62	42.69	33.11	33.11	0.00	0.00	12.85	12.85	88.64	389.21
6	496.63	10.38	0.00	29.64	40.02	33.11	33.11	0.00	0.00	12.04	12.04	85.17	444.54
7	463.52	9.69	0.00	27.67	37.35	33.11	33.11	0.00	0.00	11.24	11.24	81.70	493.94
8	430.41	9.00	0.00	25.69	34.68	33.11	33.11	0.00	0.00	10.44	10.44	78.23	537.95
9	397.30	8.30	0.00	23.71	32.02	33.11	33.11	0.00	0.00	9.63	9.63	74.76	577.09
10	364.20	7.61	0.00	21.74	29.35	33.11	33.11	0.00	0.00	8.83	8.83	71.29	611.83
11	331.09	6.92	0.00	19.76	26.68	33.11	33.11	0.00	0.00	8.03	8.03	67.82	642.58
12	297.98	6.23	0.00	17.78	24.01	33.11	33.11	0.00	0.00	7.23	7.23	64.35	669.73
13	264.87	5.54	0.00	15.81	21.34	33.11	33.11	0.00	0.00	6.42	6.42	60.88	693.64
14	231.76	4.84	0.00	13.83	18.68	33.11	33.11	0.00	0.00	5.62	5.62	57.41	714.62
15	198.65	4.15	0.00	11.86	16.01	33.11	33.11	0.00	0.00	4.82	4.82	53.93	732.96
16	165.54	3.46	0.00	9.88	13.34	33.11	33.11	0.00	0.00	4.01	4.01	50.46	748.93
17	132.43	2.77	0.00	7.90	10.67	33.11	33.11	0.00	0.00	3.21	3.21	46.99	762.78
18	99.33	2.08	0.00	5.93	8.00	33.11	33.11	0.00	0.00	2.41	2.41	43.52	774.71
19	66.22	1.38	0.00	3.95	5.34	33.11	33.11	0.00	0.00	1.61	1.61	40.05	784.92
20	33.11	0.69	0.00	1.98	2.67	33.11	33.11	0.00	0.00	0.80	0.80	36.58	793.61

PV Tax Shields	338.69
Tax on shields	97.86
Investment	662.17
After Tax Investment	564.32

Adjust for Tax Gross-Up 793.61 <------------------------------ = ------------------------------> PV Rev Req 793.61

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
95 W LED Installation

Financial Input	Input
Capital Investment - Material	$480 59
Capitalized Labor	$228 59
Total Capitalized Investment	$709 18

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$849 95
Levelized Annual Revenue Requirement	$83 09
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$83 09
Net Monthly Tariff Rate	$6 92
PA Gross Receipts Tax	$0 43
Total Monthly Distribution Rate	**$7.36**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	709 18	14 82	0 00	42 33	57 15	35 46	35 46	0 00	0 00	17 20	17 20	109 81	102 19
2	673 73	14 08	0 00	40 21	54 29	35 46	35 46	0 00	0 00	16 34	16 34	106 09	194 07
3	638 27	13 34	0 00	38 09	51 43	35 46	35 46	0 00	0 00	15 48	15 48	102 37	276 58
4	602 81	12 60	0 00	35 98	48 58	35 46	35 46	0 00	0 00	14 62	14 62	98 65	350 58
5	567 35	11 86	0 00	33 86	45 72	35 46	35 46	0 00	0 00	13 76	13 76	94 94	416 85
6	531 89	11 12	0 00	31 75	42 86	35 46	35 46	0 00	0 00	12 90	12 90	91 22	476 10
7	496 43	10 38	0 00	29 63	40 00	35 46	35 46	0 00	0 00	12 04	12 04	87 50	529 00
8	460 97	9 63	0 00	27 51	37 15	35 46	35 46	0 00	0 00	11 18	11 18	83 79	576 14
9	425 51	8 89	0 00	25 40	34 29	35 46	35 46	0 00	0 00	10 32	10 32	80 07	618 06
10	390 05	8 15	0 00	23 28	31 43	35 46	35 46	0 00	0 00	9 46	9 46	76 35	655 26
11	354 59	7 41	0 00	21 16	28 57	35 46	35 46	0 00	0 00	8 60	8 60	72 63	688 20
12	319 13	6 67	0 00	19 05	25 72	35 46	35 46	0 00	0 00	7 74	7 74	68 92	717 28
13	283 67	5 93	0 00	16 93	22 86	35 46	35 46	0 00	0 00	6 88	6 88	65 20	742 88
14	248 21	5 19	0 00	14 81	20 00	35 46	35 46	0 00	0 00	6 02	6 02	61 48	765 35
15	212 76	4 45	0 00	12 70	17 14	35 46	35 46	0 00	0 00	5 16	5 16	57 76	785 00
16	177 30	3 71	0 00	10 58	14 29	35 46	35 46	0 00	0 00	4 30	4 30	54 05	802 10
17	141 84	2 96	0 00	8 47	11 43	35 46	35 46	0 00	0 00	3 44	3 44	50 33	816 93
18	106 38	2 22	0 00	6 35	8 57	35 46	35 46	0 00	0 00	2 58	2 58	46 61	829 71
19	70 92	1 48	0 00	4 23	5 71	35 46	35 46	0 00	0 00	1 72	1 72	42 89	840 65
20	35 46	0 74	0 00	2 12	2 86	35 46	35 46	0 00	0 00	0 86	0 86	39 18	849 95

PV Tax Shields	362 74
Tax on shields	104 80
Investment	709 18
After Tax Investment	604 38

Adjust for Tax Gross-Up 849.95 <-------------------------------- = --------------------------------> PV Rev Req 849.95

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
139 W LED Installation

Financial Input	Input
Capital Investment - Material	$584 22
Capitalized Labor	$228 59
Total Capitalized Investment	$812 81

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$974 15
Levelized Annual Revenue Requirement	$95 23
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$95 23
Net Monthly Tariff Rate	$7 94
PA Gross Receipts Tax	$0 50
Total Monthly Distribution Rate	**$8.43**

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	812 81	16 99	0 00	48 51	65 50	40 64	40 64	0 00	0 00	19 71	19 71	125 85	117 12
2	772 17	16 14	0 00	46 09	62 23	40 64	40 64	0 00	0 00	18 73	18 73	121 59	222 43
3	731 53	15 29	0 00	43 66	58 95	40 64	40 64	0 00	0 00	17 74	17 74	117 33	316 99
4	690 89	14 44	0 00	41 24	55 68	40 64	40 64	0 00	0 00	16 75	16 75	113 07	401 80
5	650 25	13 59	0 00	38 81	52 40	40 64	40 64	0 00	0 00	15 77	15 77	108 81	477 76
6	609 61	12 74	0 00	36 38	49 13	40 64	40 64	0 00	0 00	14 78	14 78	104 55	545 67
7	568 97	11 89	0 00	33 96	45 85	40 64	40 64	0 00	0 00	13 80	13 80	100 29	606 30
8	528 33	11 04	0 00	31 53	42 58	40 64	40 64	0 00	0 00	12 81	12 81	96 03	660 33
9	487 69	10 19	0 00	29 11	39 30	40 64	40 64	0 00	0 00	11 83	11 83	91 77	708 37
10	447 05	9 34	0 00	26 68	36 03	40 64	40 64	0 00	0 00	10 84	10 84	87 51	751 01
11	406 41	8 49	0 00	24 26	32 75	40 64	40 64	0 00	0 00	9 86	9 86	83 25	788 76
12	365 77	7 64	0 00	21 83	29 48	40 64	40 64	0 00	0 00	8 87	8 87	78 99	822 09
13	325 13	6 80	0 00	19 41	26 20	40 64	40 64	0 00	0 00	7 88	7 88	74 73	851 44
14	284 49	5 95	0 00	16 98	22 93	40 64	40 64	0 00	0 00	6 90	6 90	70 46	877 19
15	243 84	5 10	0 00	14 55	19 65	40 64	40 64	0 00	0 00	5 91	5 91	66 20	899 71
16	203 20	4 25	0 00	12 13	16 38	40 64	40 64	0 00	0 00	4 93	4 93	61 94	919 31
17	162 56	3 40	0 00	9 70	13 10	40 64	40 64	0 00	0 00	3 94	3 94	57 68	936 30
18	121 92	2 55	0 00	7 28	9 83	40 64	40 64	0 00	0 00	2 96	2 96	53 42	950 95
19	81 28	1 70	0 00	4 85	6 55	40 64	40 64	0 00	0 00	1 97	1 97	49 16	963 49
20	40 64	0 85	0 00	2 43	3 28	40 64	40 64	0 00	0 00	0 99	0 99	44 90	974 15

PV Tax Shields	415 75
Tax on shields	120 12
Investment	812 81
After Tax Investment	692 70

Adjust for Tax Gross-Up $\boxed{974.15}$ <------------------------------ = ------------------------------> PV Rev Req $\boxed{974.15}$

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
219 W LED Installation

Financial Input	Input
Capital Investment - Material	$822 02
Capitalized Labor	$228 59
Total Capitalized Investment	$1,050 61

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$1,259 15
Levelized Annual Revenue Requirement	$123 09
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$123 09
Net Monthly Tariff Rate	$10 26
PA Gross Receipts Tax	$0 64
Total Monthly Distribution Rate	**$10.90**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	1,050 61	21 96	0 00	62 71	84 66	52 53	52 53	0 00	0 00	25 48	25 48	162 67	151 39
2	998 08	20 86	0 00	59 57	80 43	52 53	52 53	0 00	0 00	24 20	24 20	157 17	287 50
3	945 55	19 76	0 00	56 44	76 20	52 53	52 53	0 00	0 00	22 93	22 93	151 66	409 74
4	893 02	18 66	0 00	53 30	71 96	52 53	52 53	0 00	0 00	21 66	21 66	146 15	519 36
5	840 49	17 57	0 00	50 16	67 73	52 53	52 53	0 00	0 00	20 38	20 38	140 64	617 53
6	787 96	16 47	0 00	47 03	63 50	52 53	52 53	0 00	0 00	19 11	19 11	135 14	705 32
7	735 43	15 37	0 00	43 89	59 26	52 53	52 53	0 00	0 00	17 83	17 83	129 63	783 68
8	682 90	14 27	0 00	40 76	55 03	52 53	52 53	0 00	0 00	16 56	16 56	124 12	853 52
9	630 37	13 17	0 00	37 62	50 80	52 53	52 53	0 00	0 00	15 29	15 29	118 62	915 62
10	577 84	12 08	0 00	34 49	46 56	52 53	52 53	0 00	0 00	14 01	14 01	113 11	970 73
11	525 31	10 98	0 00	31 35	42 33	52 53	52 53	0 00	0 00	12 74	12 74	107 60	1,019 52
12	472 78	9 88	0 00	28 22	38 10	52 53	52 53	0 00	0 00	11 47	11 47	102 09	1,062 60
13	420 25	8 78	0 00	25 08	33 87	52 53	52 53	0 00	0 00	10 19	10 19	96 59	1,100 54
14	367 72	7 69	0 00	21 95	29 63	52 53	52 53	0 00	0 00	8 92	8 92	91 08	1,133 82
15	315 18	6 59	0 00	18 81	25 40	52 53	52 53	0 00	0 00	7 64	7 64	85 57	1,162 93
16	262 65	5 49	0 00	15 68	21 17	52 53	52 53	0 00	0 00	6 37	6 37	80 07	1,188 27
17	210 12	4 39	0 00	12 54	16 93	52 53	52 53	0 00	0 00	5 10	5 10	74 56	1,210 23
18	157 59	3 29	0 00	9 41	12 70	52 53	52 53	0 00	0 00	3 82	3 82	69 05	1,229 16
19	105 06	2 20	0 00	6 27	8 47	52 53	52 53	0 00	0 00	2 55	2 55	63 54	1,245 37
20	52 53	1 10	0 00	3 14	4 23	52 53	52 53	0 00	0 00	1 27	1 27	58 04	1,259 15

PV Tax Shields	537 38
Tax on shields	155 26
Investment	1,050 61
After Tax Investment	895 35

Adjust for Tax Gross-Up 1,259.15 <---------------------------- = ----------------------------> PV Rev Req 1,259.15

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
275 W LED Installation

Financial Input	Input
Capital Investment - Material	$985 65
Capitalized Labor	$228 59
Total Capitalized Investment	$1,214 24

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$1,455 26
Levelized Annual Revenue Requirement	$142 26
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$142 26
Net Monthly Tariff Rate	$11 86
PA Gross Receipts Tax	$0 74
Total Monthly Distribution Rate	**$12.60**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	1,214 24	25 38	0 00	72 47	97 85	60 71	60 71	0 00	0 00	29 45	29 45	188 01	174 96
2	1,153 53	24 11	0 00	68 85	92 96	60 71	60 71	0 00	0 00	27 97	27 97	181 64	332 28
3	1,092 82	22 84	0 00	65 22	88 06	60 71	60 71	0 00	0 00	26 50	26 50	175 28	473 55
4	1,032 11	21 57	0 00	61 60	83 17	60 71	60 71	0 00	0 00	25 03	25 03	168 91	600 25
5	971 40	20 30	0 00	57 98	78 28	60 71	60 71	0 00	0 00	23 56	23 56	162 55	713 71
6	910 68	19 03	0 00	54 35	73 39	60 71	60 71	0 00	0 00	22 08	22 08	156 18	815 17
7	849 97	17 76	0 00	50 73	68 49	60 71	60 71	0 00	0 00	20 61	20 61	149 82	905 74
8	789 26	16 50	0 00	47 11	63 60	60 71	60 71	0 00	0 00	19 14	19 14	143 45	986 45
9	728 55	15 23	0 00	43 48	58 71	60 71	60 71	0 00	0 00	17 67	17 67	137 09	1,058 22
10	667 83	13 96	0 00	39 86	53 82	60 71	60 71	0 00	0 00	16 20	16 20	130 72	1,121 92
11	607 12	12 69	0 00	36 24	48 92	60 71	60 71	0 00	0 00	14 72	14 72	124 36	1,178 31
12	546 41	11 42	0 00	32 61	44 03	60 71	60 71	0 00	0 00	13 25	13 25	118 00	1,228 10
13	485 70	10 15	0 00	28 99	39 14	60 71	60 71	0 00	0 00	11 78	11 78	111 63	1,271 94
14	424 99	8 88	0 00	25 37	34 25	60 71	60 71	0 00	0 00	10 31	10 31	105 27	1,310 41
15	364 27	7 61	0 00	21 74	29 35	60 71	60 71	0 00	0 00	8 83	8 83	98 90	1,344 05
16	303 56	6 34	0 00	18 12	24 46	60 71	60 71	0 00	0 00	7 36	7 36	92 54	1,373 34
17	242 85	5 08	0 00	14 49	19 57	60 71	60 71	0 00	0 00	5 89	5 89	86 17	1,398 72
18	182 14	3 81	0 00	10 87	14 68	60 71	60 71	0 00	0 00	4 42	4 42	79 81	1,420 60
19	121 42	2 54	0 00	7 25	9 78	60 71	60 71	0 00	0 00	2 94	2 94	73 44	1,439 33
20	60 71	1 27	0 00	3 62	4 89	60 71	60 71	0 00	0 00	1 47	1 47	67 08	1,455 26

PV Tax Shields	621 07
Tax on shields	179 44
Investment	1,214 24
After Tax Investment	1,034 80

Adjust for Tax Gross-Up 1,455.26 <------------------------------ = ------------------------------> PV Rev Req 1,455.26

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
48 W LED Installation

Financial Input	Input
Capital Investment - Material	$305 00
Capitalized Labor	$228 59
Total Capitalized Investment	$533 59

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$639 51
Levelized Annual Revenue Requirement	$62 51
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$62 51
Net Monthly Tariff Rate	$5 21
PA Gross Receipts Tax	$0 33
Total Monthly Distribution Rate	**$5.54**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	533 59	11 15	0 00	31 85	43 00	26 68	26 68	0 00	0 00	12 94	12 94	82 62	76 89
2	506 91	10 59	0 00	30 26	40 85	26 68	26 68	0 00	0 00	12 29	12 29	79 82	146 02
3	480 23	10 04	0 00	28 66	38 70	26 68	26 68	0 00	0 00	11 65	11 65	77 03	208 10
4	453 56	9 48	0 00	27 07	36 55	26 68	26 68	0 00	0 00	11 00	11 00	74 23	263 78
5	426 88	8 92	0 00	25 48	34 40	26 68	26 68	0 00	0 00	10 35	10 35	71 43	313 64
6	400 20	8 36	0 00	23 89	32 25	26 68	26 68	0 00	0 00	9 71	9 71	68 63	358 22
7	373 52	7 81	0 00	22 29	30 10	26 68	26 68	0 00	0 00	9 06	9 06	65 84	398 02
8	346 84	7 25	0 00	20 70	27 95	26 68	26 68	0 00	0 00	8 41	8 41	63 04	433 49
9	320 16	6 69	0 00	19 11	25 80	26 68	26 68	0 00	0 00	7 76	7 76	60 24	465 03
10	293 48	6 13	0 00	17 52	23 65	26 68	26 68	0 00	0 00	7 12	7 12	57 45	493 02
11	266 80	5 58	0 00	15 92	21 50	26 68	26 68	0 00	0 00	6 47	6 47	54 65	517 80
12	240 12	5 02	0 00	14 33	19 35	26 68	26 68	0 00	0 00	5 82	5 82	51 85	539 68
13	213 44	4 46	0 00	12 74	17 20	26 68	26 68	0 00	0 00	5 18	5 18	49 06	558 95
14	186 76	3 90	0 00	11 15	15 05	26 68	26 68	0 00	0 00	4 53	4 53	46 26	575 85
15	160 08	3 35	0 00	9 55	12 90	26 68	26 68	0 00	0 00	3 88	3 88	43 46	590 64
16	133 40	2 79	0 00	7 96	10 75	26 68	26 68	0 00	0 00	3 24	3 24	40 66	603 51
17	106 72	2 23	0 00	6 37	8 60	26 68	26 68	0 00	0 00	2 59	2 59	37 87	614 66
18	80 04	1 67	0 00	4 78	6 45	26 68	26 68	0 00	0 00	1 94	1 94	35 07	624 28
19	53 36	1 12	0 00	3 18	4 30	26 68	26 68	0 00	0 00	1 29	1 29	32 27	632 51
20	26 68	0 56	0 00	1 59	2 15	26 68	26 68	0 00	0 00	0 65	0 65	29 48	639 51

PV Tax Shields	272 93
Tax on shields	78 85
Investment	533 59
After Tax Investment	454 74

Adjust for Tax Gross-Up $\boxed{639.51}$ <------------------------------ = ------------------------------> PV Rev Req $\boxed{639.51}$

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
83 W LED Installation

Financial Input	Input
Capital Investment - Material	$305 00
Capitalized Labor	$228 59
Total Capitalized Investment	$533 59

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$639 51
Levelized Annual Revenue Requirement	$62 51
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$62 51
Net Monthly Tariff Rate	$5 21
PA Gross Receipts Tax	$0 33
Total Monthly Distribution Rate	**$5.54**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	533 59	11 15	0 00	31 85	43 00	26 68	26 68	0 00	0 00	12 94	12 94	82 62	76 89
2	506 91	10 59	0 00	30 26	40 85	26 68	26 68	0 00	0 00	12 29	12 29	79 82	146 02
3	480 23	10 04	0 00	28 66	38 70	26 68	26 68	0 00	0 00	11 65	11 65	77 03	208 10
4	453 56	9 48	0 00	27 07	36 55	26 68	26 68	0 00	0 00	11 00	11 00	74 23	263 78
5	426 88	8 92	0 00	25 48	34 40	26 68	26 68	0 00	0 00	10 35	10 35	71 43	313 64
6	400 20	8 36	0 00	23 89	32 25	26 68	26 68	0 00	0 00	9 71	9 71	68 63	358 22
7	373 52	7 81	0 00	22 29	30 10	26 68	26 68	0 00	0 00	9 06	9 06	65 84	398 02
8	346 84	7 25	0 00	20 70	27 95	26 68	26 68	0 00	0 00	8 41	8 41	63 04	433 49
9	320 16	6 69	0 00	19 11	25 80	26 68	26 68	0 00	0 00	7 76	7 76	60 24	465 03
10	293 48	6 13	0 00	17 52	23 65	26 68	26 68	0 00	0 00	7 12	7 12	57 45	493 02
11	266 80	5 58	0 00	15 92	21 50	26 68	26 68	0 00	0 00	6 47	6 47	54 65	517 80
12	240 12	5 02	0 00	14 33	19 35	26 68	26 68	0 00	0 00	5 82	5 82	51 85	539 68
13	213 44	4 46	0 00	12 74	17 20	26 68	26 68	0 00	0 00	5 18	5 18	49 06	558 95
14	186 76	3 90	0 00	11 15	15 05	26 68	26 68	0 00	0 00	4 53	4 53	46 26	575 85
15	160 08	3 35	0 00	9 55	12 90	26 68	26 68	0 00	0 00	3 88	3 88	43 46	590 64
16	133 40	2 79	0 00	7 96	10 75	26 68	26 68	0 00	0 00	3 24	3 24	40 66	603 51
17	106 72	2 23	0 00	6 37	8 60	26 68	26 68	0 00	0 00	2 59	2 59	37 87	614 66
18	80 04	1 67	0 00	4 78	6 45	26 68	26 68	0 00	0 00	1 94	1 94	35 07	624 28
19	53 36	1 12	0 00	3 18	4 30	26 68	26 68	0 00	0 00	1 29	1 29	32 27	632 51
20	26 68	0 56	0 00	1 59	2 15	26 68	26 68	0 00	0 00	0 65	0 65	29 48	639 51

PV Tax Shields	272 93
Tax on shields	78 85
Investment	533.59
After Tax Investment	454 74

Adjust for Tax Gross-Up $\boxed{639.51}$ <———————— = ————————> PV Rev Req $\boxed{639.51}$

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
47 W LED Installation

Financial Input	Input
Capital Investment - Matenal	$498 91
Capitalized Labor	$228 59
Total Capitalized Investment	$727 50

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$871 91
Levelized Annual Revenue Requirement	$85 23
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$85 23
Net Monthly Tariff Rate	$7 10
PA Gross Receipts Tax	$0 45
Total Monthly Distribution Rate	**$7.55**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	727 50	15 20	0 00	43 42	58 63	36 38	36 38	0 00	0 00	17 64	17 64	112 64	104 83
2	691 13	14 44	0 00	41 25	55 69	36 38	36 38	0 00	0 00	16 76	16 76	108 83	199 08
3	654 75	13 68	0 00	39 08	52 76	36 38	36 38	0 00	0 00	15 88	15 88	105 02	283 72
4	618 38	12 92	0 00	36 91	49 83	36 38	36 38	0 00	0 00	15 00	15 00	101 20	359 63
5	582 00	12 16	0 00	34 74	46 90	36 38	36 38	0 00	0 00	14 11	14 11	97 39	427 61
6	545 63	11 40	0 00	32 57	43 97	36 38	36 38	0 00	0 00	13 23	13 23	93 58	488 40
7	509 25	10 64	0 00	30 39	41 04	36 38	36 38	0 00	0 00	12 35	12 35	89 76	542 67
8	472 88	9 88	0 00	28 22	38 11	36 38	36 38	0 00	0 00	11 47	11 47	85 95	591 02
9	436 50	9 12	0 00	26 05	35 18	36 38	36 38	0 00	0 00	10 59	10 59	82 14	634 03
10	400 13	8 36	0 00	23 88	32 24	36 38	36 38	0 00	0 00	9 70	9 70	78 32	672 19
11	363 75	7 60	0 00	21 71	29 31	36 38	36 38	0 00	0 00	8 82	8 82	74 51	705 97
12	327 38	6 84	0 00	19 54	26 38	36 38	36 38	0 00	0 00	7 94	7 94	70 70	735 81
13	291 00	6 08	0 00	17 37	23 45	36 38	36 38	0 00	0 00	7 06	7 06	66 88	762 07
14	254 63	5 32	0 00	15 20	20 52	36 38	36 38	0 00	0 00	6 17	6 17	63 07	785 12
15	218 25	4 56	0 00	13 03	17 59	36 38	36 38	0 00	0 00	5 29	5 29	59 26	805 28
16	181 88	3 80	0 00	10 86	14 66	36 38	36 38	0 00	0 00	4 41	4 41	55 44	822 82
17	145 50	3 04	0 00	8 68	11 73	36 38	36 38	0 00	0 00	3 53	3 53	51 63	838 03
18	109 13	2 28	0 00	6 51	8 79	36 38	36 38	0 00	0 00	2 65	2 65	47 82	851 14
19	72 75	1 52	0 00	4 34	5 86	36 38	36 38	0 00	0 00	1 76	1 76	44 00	862 36
20	36 38	0 76	0 00	2 17	2 93	36 38	36 38	0 00	0 00	0 88	0 88	40 19	871 91

PV Tax Shields	372 11
Tax on shields	107 51
Investment	727 50
After Tax Investment	619 99

Adjust for Tax Gross-Up 871.91 <------------------------------ = ------------------------------> PV Rev Req 871.91

Exhibit DBO-4
Duquesne Light Company
Calculation of Monthly Distribution Rate
62 W LED Installation

Financial Input	Input
Capital Investment - Material	$498 91
Capitalized Labor	$228 59
Total Capitalized Investment	$727 50

Years for straight line book depreciation		20
Book Depreciation Rate		5 00%
Years for straight line tax depreciation		20
Tax Depreciation Rate		5 00%
Tax Rate	State	9 99%
	Federal	21 00%
	Combined	28 89%
	Gross Revenue Adjustment	71 11%
	Gross Revenue Conversion Factor	1 40631
PA Gross Receipts Tax		5 90%

Weighted Cost of Capital

	Capitalization Ratio	Rate	Weighted Return	WATCC
Debt	45 49%	4 60%	2 09%	1 49%
Preferred	0 00%	0 00%	0 00%	0 00%
Equity	54 51%	10 95%	5 97%	5 97%
	100 00%		8 06%	7 45%

Monthly Distribution Rate

Sum of PV of Revenue Requirement	$871 91
Levelized Annual Revenue Requirement	$85 23
Annual O&M / Maintenance Expense	$0 00
Annual Revenue Requirement	$85 23
Net Monthly Tariff Rate	$7 10
PA Gross Receipts Tax	$0 45
Total Monthly Distribution Rate	**$7.55**

A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Capital	**Return**				**Deferred Tax on Depreciation**			**Tax**			**Total**	
Year	B O Y Plant	Return on Debt	Return on Preferred	Return on Equity	Total Return on Net Plant	Book Deprec	Tax Deprec	E O Y Def Inc Tax	Income Tax on Preferred	Income Tax on Equity	Total Income Taxes	Revenue Requirement	Cumulative NPV
					C+D+E			(H-G)*Tax	D*(Tax/(1-Tax))	E*(Tax/(1-Tax))	J+K	F+G+L	
1	727 50	15 20	0 00	43 42	58 63	36 38	36 38	0 00	0 00	17 64	17 64	112 64	104 83
2	691 13	14 44	0 00	41 25	55 69	36 38	36 38	0 00	0 00	16 76	16 76	108 83	199 08
3	654 75	13 68	0 00	39 08	52 76	36 38	36 38	0 00	0 00	15 88	15 88	105 02	283 72
4	618 38	12 92	0 00	36 91	49 83	36 38	36 38	0 00	0 00	15 00	15 00	101 20	359 63
5	582 00	12 16	0 00	34 74	46 90	36 38	36 38	0 00	0 00	14 11	14 11	97 39	427 61
6	545 63	11 40	0 00	32 57	43 97	36 38	36 38	0 00	0 00	13 23	13 23	93 58	488 40
7	509 25	10 64	0 00	30 39	41 04	36 38	36 38	0 00	0 00	12 35	12 35	89 76	542 67
8	472 88	9 88	0 00	28 22	38 11	36 38	36 38	0 00	0 00	11 47	11 47	85 95	591 02
9	436 50	9 12	0 00	26 05	35 18	36 38	36 38	0 00	0 00	10 59	10 59	82 14	634 03
10	400 13	8 36	0 00	23 88	32 24	36 38	36 38	0 00	0 00	9 70	9 70	78 32	672 19
11	363 75	7 60	0 00	21 71	29 31	36 38	36 38	0 00	0 00	8 82	8 82	74 51	705 97
12	327 38	6 84	0 00	19 54	26 38	36 38	36 38	0 00	0 00	7 94	7 94	70 70	735 81
13	291 00	6 08	0 00	17 37	23 45	36 38	36 38	0 00	0 00	7 06	7 06	66 88	762 07
14	254 63	5 32	0 00	15 20	20 52	36 38	36 38	0 00	0 00	6 17	6 17	63 07	785 12
15	218 25	4 56	0 00	13 03	17 59	36 38	36 38	0 00	0 00	5 29	5 29	59 26	805 28
16	181 88	3 80	0 00	10 86	14 66	36 38	36 38	0 00	0 00	4 41	4 41	55 44	822 82
17	145 50	3 04	0 00	8 68	11 73	36 38	36 38	0 00	0 00	3 53	3 53	51 63	838 03
18	109 13	2 28	0 00	6 51	8 79	36 38	36 38	0 00	0 00	2 65	2 65	47 82	851 14
19	72 75	1 52	0 00	4 34	5 86	36 38	36 38	0 00	0 00	1 76	1 76	44 00	862 36
20	36 38	0 76	0 00	2 17	2 93	36 38	36 38	0 00	0 00	0 88	0 88	40 19	871 91

PV Tax Shields	372 11
Tax on shields	107 51
Investment	727 50
After Tax Investment	619 99

Adjust for Tax Gross-Up **871.91** <------------------------------ = ------------------------------> PV Rev Req **871.91**

Exhibit DBO-5
Duquesne Light Company
Updated Unbundling Default Service Costs

					A = (B * 4)	B = (C+D+E+F)	C	D	E	F
					Total	Annualized	Forecasted Annual Default Service Costs by Customer Class			
Line	Item	Current Recovery Mechanism	Proposed Recovery Mechanism	Description	Total Estimated Costs	Annualized Estimated Costs	Residential & Lighting	Small C&I	Medium C&I	Large C&I
1	Forecasted POLR Sales (MWh) - 6.1.2018 - 5.31.2019					3,878,000	2,671,000	354,000	685,000	168,000
2	Unbundled Default Service Costs									
3	Filing Preparation and Approval Process	Default Service Supply Rates	Default Service Supply Rates (Allocated on forecasted POLR MWhs)	Consulting services and outside counsel to help prepare filing and throughout regulatory process	$792,828	$198,207	$136,516	$18,093	$35,011	$8,587
4	Working Capital for Default Service Supply [1]	Default Service Supply Rates	Default Service Supply Rates (Allocated on forecasted POLR MWhs)	Costs associated with lag in time between the utility's out-of-pocket payment expenses and the collection of revenues for default service.	$6,063,235	$1,515,809	$1,044,024	$138,369	$267,749	$65,667
5	**Total (Line 3 + Line 4)**				**$6,856,063**	**$1,714,016**	**$1,180,540**	**$156,462**	**$302,759**	**$74,253**

1/ Assuming the Company's pre-tax weighted cost of capital of ~10 49%, the revenue requirement (annual expense) associated with DSS working capital is $1,515,809 [$14,451,988 multiplied by ~10 49% return]. The cash working capital cost of $14,451,988 is based on the supply related working capital costs excluded from distribution base rates in the Company's current base rate proceeding on Exhibit 6-1, page 2 of 6, line 66